# A BALANCED APPROACH

SIERRA PACIFIC RESOURCES 2007 ANNUAL REPORT

Sierra Pacific™
RESOURCES

# STRATEGIC

Sierra Pacific Resources is an investor-owned corporation with operating subsidiaries engaged in the utility business, principally in the State of Nevada. The company's stock is traded on the New York Stock Exchange under the symbol SRP. ¶ Its two major operating subsidiaries are Nevada Power Company, which serves approximately 826,000 electric customers in Las Vegas and surrounding areas of southern Nevada; and Sierra Pacific Power Company, which has approximately 366,000 electric customers in northern Nevada and the Lake Tahoe area of northern California, and provides natural gas service to approximately 149,000 customers in the Reno-Sparks metropolitan area of northern Nevada. ¶ The combined service area of the two utilities covers approximately 54,500 square miles. ¶ The number of registered holders of Sierra Pacific Resources' common stock was 16,293 as of December 31, 2007.

*On the cover: Sierra Pacific Power is partnering with The Nature Conservancy, Truckee Meadows Water Authority and other organizations in 2008 to preserve Independence Lake, which was acquired by the utility in 1937. We announced a similar agreement in 2007 to protect 3,350 acres of forested land in the Truckee River Canyon west of Reno.*



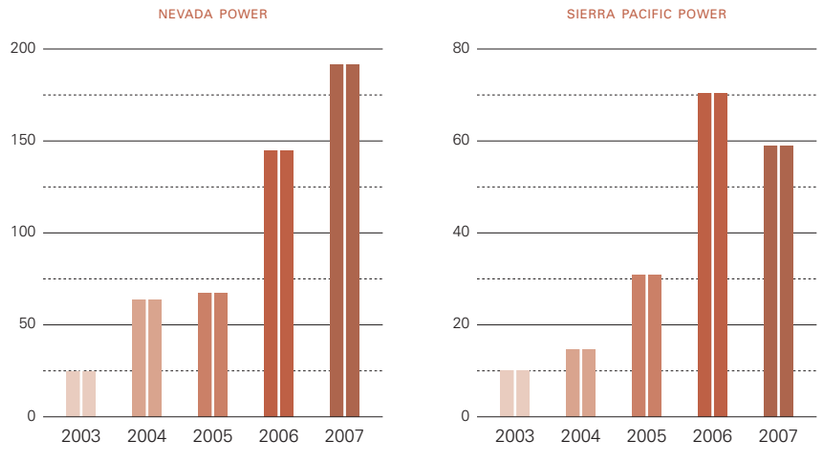
Our Three-Part Strategy


## TAKING A BALANCED APPROACH

AS THE ENERGY PROVIDER FOR NEARLY ALL OF NEVADA, SIERRA PACIFIC RESOURCES HAS AN OBLIGATION TO PROVIDE OUR CUSTOMERS WITH RELIABLE ELECTRIC AND NATURAL GAS SERVICE AT REASONABLE AND PREDICTABLE RATES. WE ARE WORKING HARD TO FULFILL OUR RESPONSIBILITIES TO ALL OUR CONSTITUENTS, INCLUDING YOU, OUR INVESTORS, WITH A REALISTIC, BALANCED THREE-PART ENERGY STRATEGY THAT'S DESCRIBED IN THE PAGES OF THIS ANNUAL REPORT. OUR STRATEGY CALLS FOR INVESTING IN: ENERGY EFFICIENCY AND CONSERVATION PROGRAMS; RENEWABLE ENERGY PROJECTS; AND NEW, HIGHLY EFFICIENT POWER GENERATION. THESE INVESTMENTS WILL CONTINUE OUR PROGRESS TOWARD NEVADA'S ENERGY INDEPENDENCE, HELP CONSUMERS MANAGE THEIR POWER COSTS, AND ESTABLISH OUR COMPANY AS A NATIONAL LEADER IN RENEWABLE ENERGY.

**Michael W. Yackira**
President & Chief Executive Officer

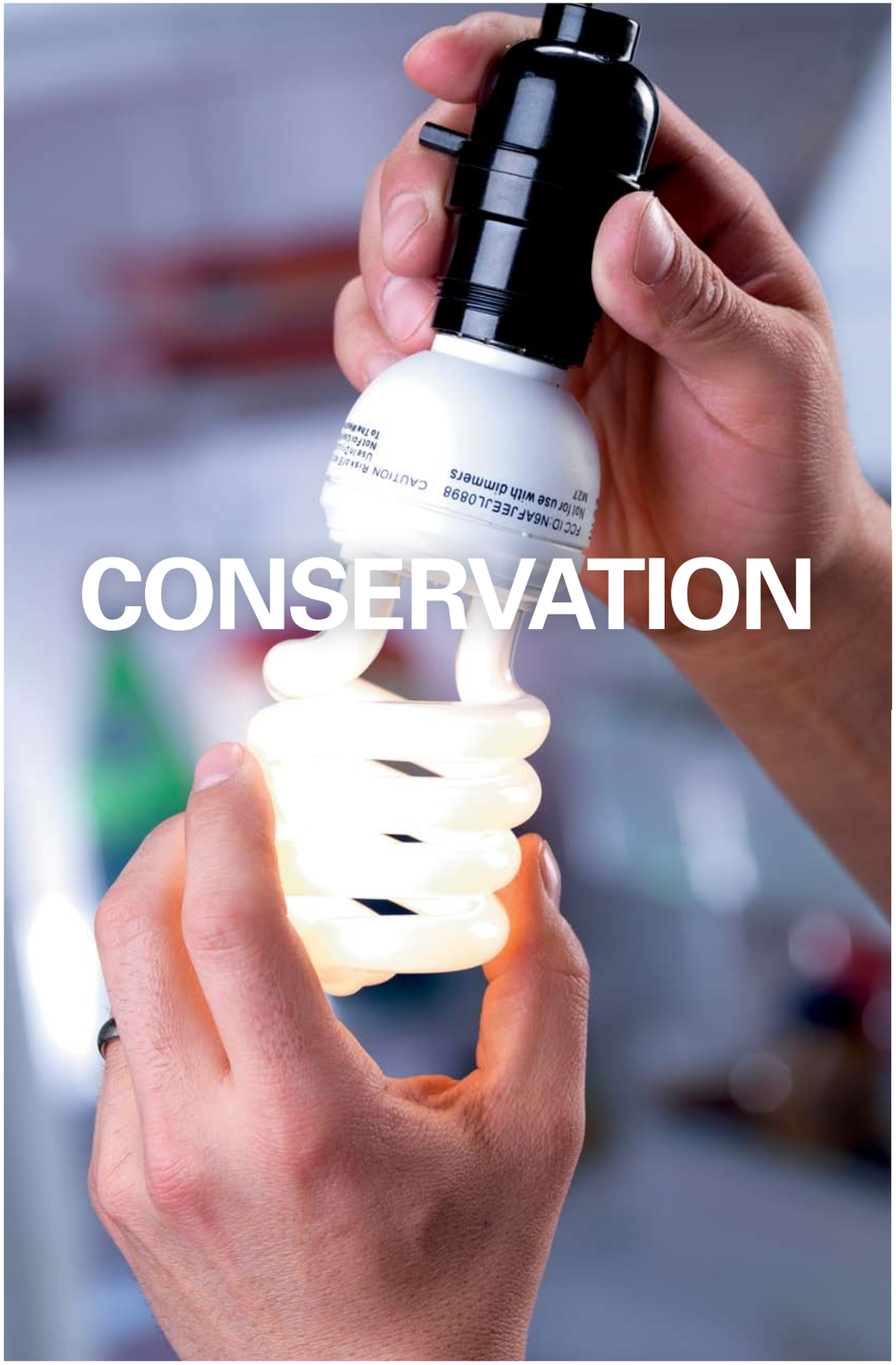
Energy Conservation Results in Millions of Kilowatt Hours

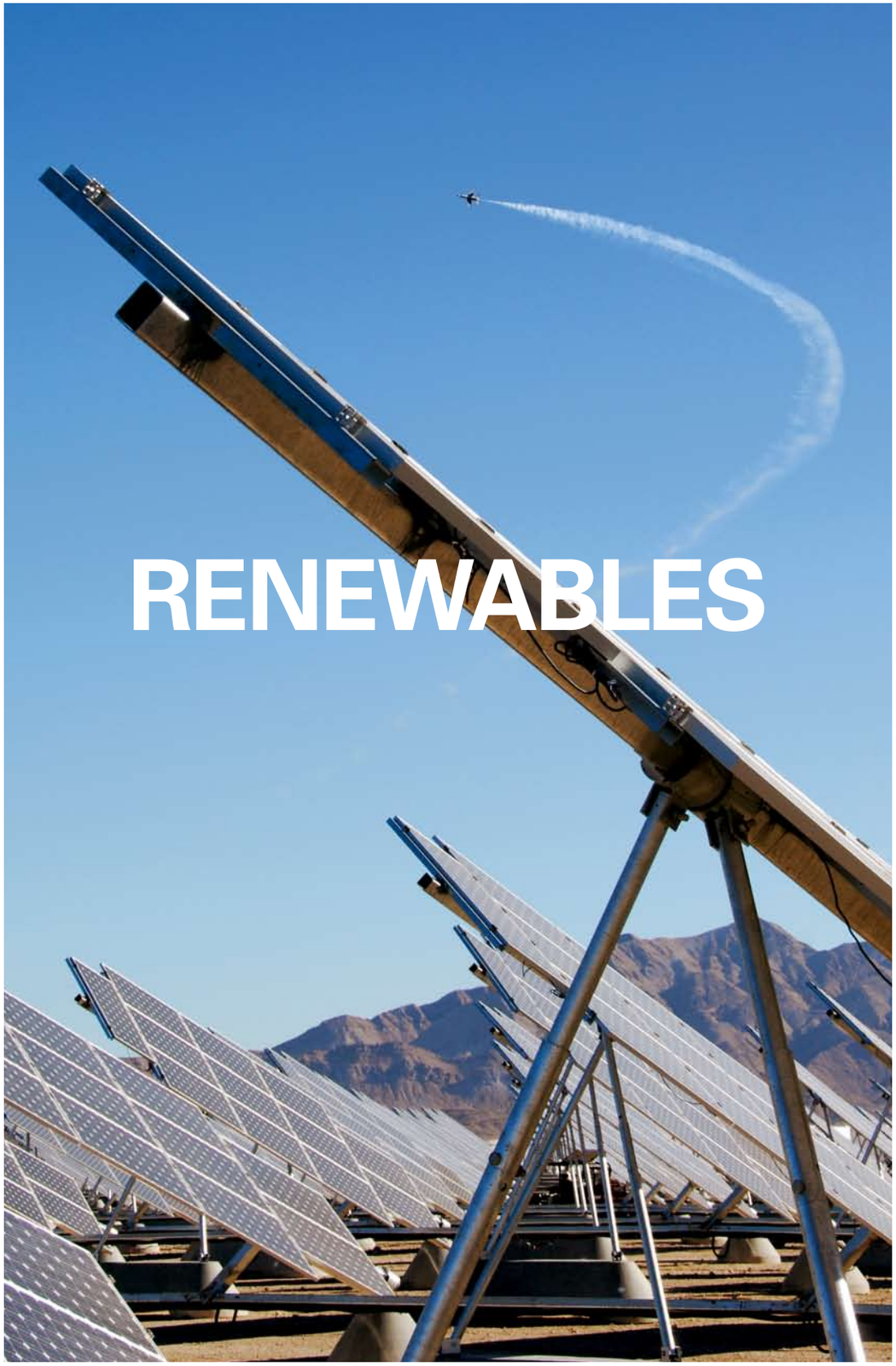



## INVESTING IN ENERGY EFFICIENCY

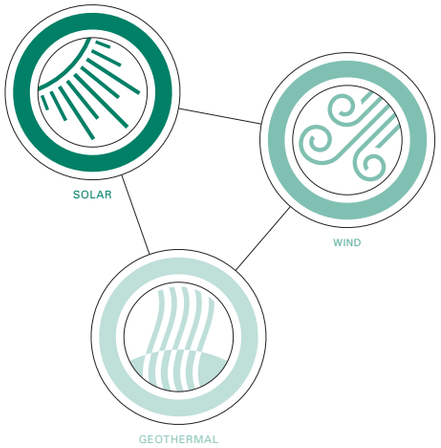
LOOKS FUNNY, SAVES MONEY WAS THE THEME FOR THE COMPANY'S 2007 CAMPAIGN TO ENCOURAGE NEVADANS TO SAVE ENERGY BY REPLACING THEIR OLD INCANDESCENT BULBS WITH COMPACT FLUORESCENT LIGHT BULBS (CFLS). OVER 2 MILLION CFLS WERE DISTRIBUTED STATEWIDE IN 2007 FOR AN ANNUAL ENERGY SAVINGS OF APPROXIMATELY 120 MILLION KILOWATT HOURS. CFL BULBS USE ABOUT 75 PERCENT LESS ENERGY THAN STANDARD INCANDESCENT BULBS AND LAST UP TO 10 TIMES LONGER. THE CFL PROGRAM IS ONE COMPONENT OF A BROAD RANGE OF ENERGY EFFICIENCY INITIATIVES FOR RESIDENTIAL AND COMMERCIAL CUSTOMERS, SCHOOLS AND PUBLIC BUILDINGS. OTHER PROGRAMS PROVIDE CUSTOMERS WITH FINANCIAL INCENTIVES FOR RECYCLING OLD, INEFFICIENT REFRIGERATORS AND FOR REDUCING AIR CONDITIONER USE IN THE SUMMER. NEVADA POWER AND SIERRA PACIFIC POWER ALSO PROVIDE GRANTS TO NEVADA-BASED NONPROFIT AGENCIES TO FUND WEATHERIZATION AND ENERGY EFFICIENT RETROFIT PROJECTS. IN 2007, OUR ENERGY EFFICIENCY PROGRAMS SAVED OVER 250 MILLION KILOWATT HOURS OF ELECTRICITY STATEWIDE.







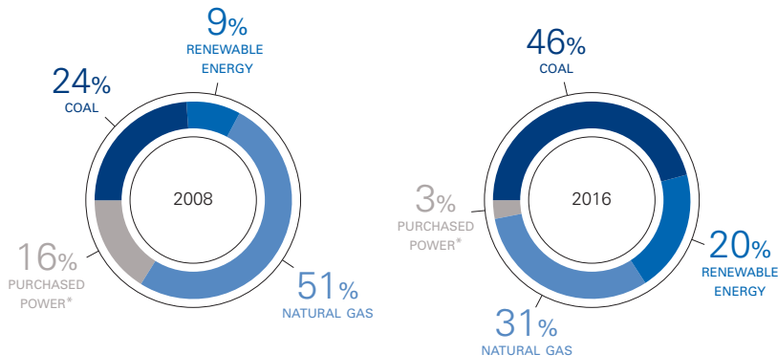

Renewable Energy




## RENEWABLE ENERGY TAKES OFF

A FIGHTER JET FROM NELLIS AIR FORCE BASE FLIES ABOVE THE PHOTOVOLTAIC SOLAR PANELS THAT ARE GENERATING 14 MEGAWATTS OF ELECTRICITY TO HELP POWER THE MILITARY BASE NORTH OF LAS VEGAS. A JOINT PROJECT OF THE U.S. AIR FORCE, NEVADA POWER COMPANY, MMA RENEWABLE VENTURES, LLC, AND SUNPOWER CORPORATION, IT IS THE LARGEST PHOTOVOLTAIC SYSTEM IN NORTH AMERICA. COMPLETED IN DECEMBER 2007, THE PROJECT IS HELPING NEVADA POWER MEET THE AMBITIOUS RENEWABLE ENERGY PORTFOLIO STANDARD SET BY THE NEVADA STATE LEGISLATURE. BY YEAR END 2007, NEVADA LED THE NATION IN BOTH SOLAR AND GEOTHERMAL POWER PER CAPITA. IN JUNE 2007, SOUTHERN NEVADA CUSTOMERS BEGAN RECEIVING 64 MEGAWATTS OF ELECTRICITY FROM THE LARGEST CAPACITY SOLAR THERMAL POWER PLANT BUILT IN THE WORLD SINCE 1991 AND THE THIRD LARGEST OF ITS KIND. SIERRA PACIFIC RESOURCES ALSO BEGAN DISCUSSIONS TO JOINTLY DEVELOP WITH ANOTHER COMPANY A 200-MEGAWATT WIND ENERGY PROJECT IN NORTHEASTERN NEVADA NEAR THE IDAHO BORDER.

Projected Power Generation Portfolio

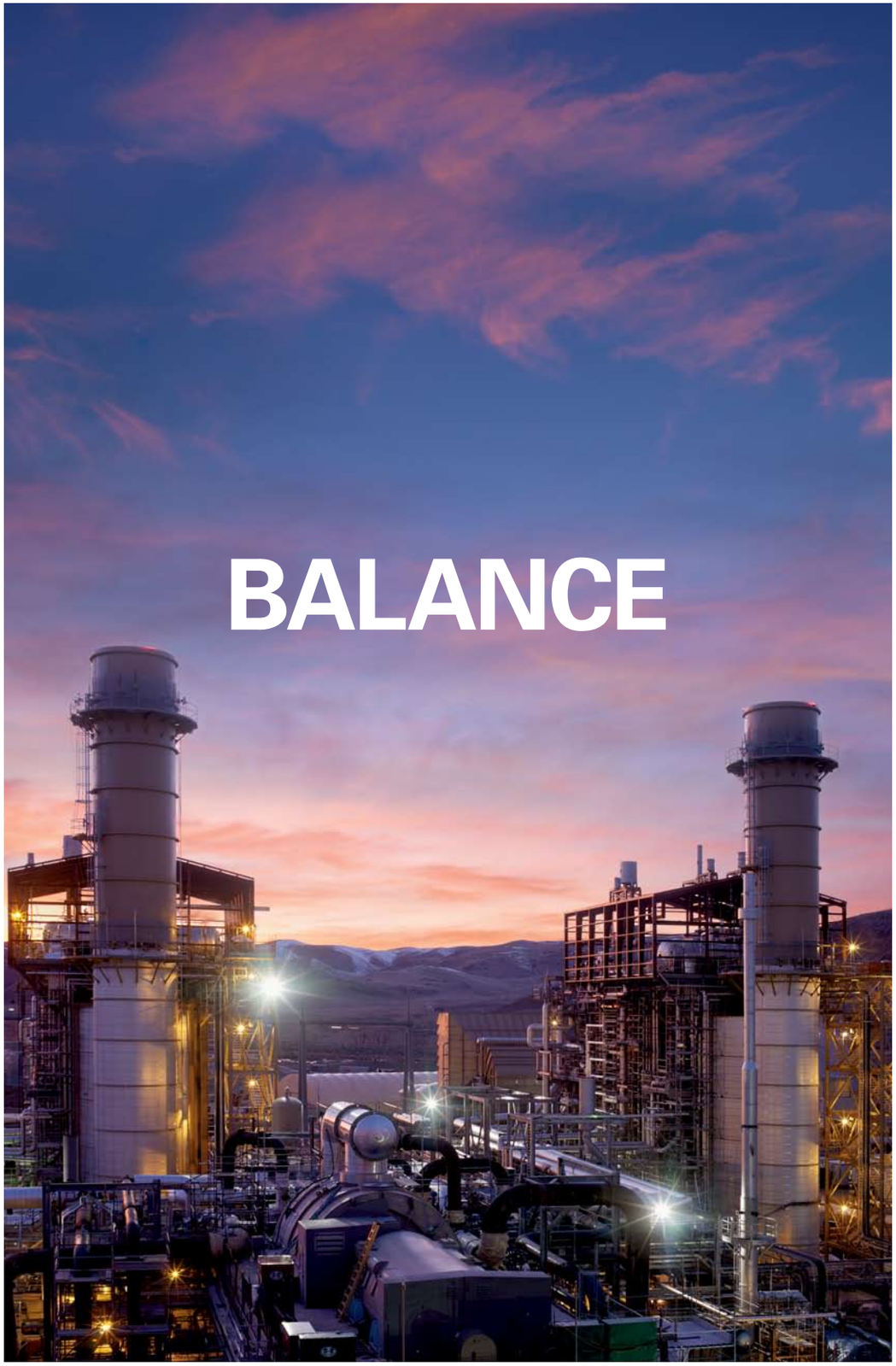


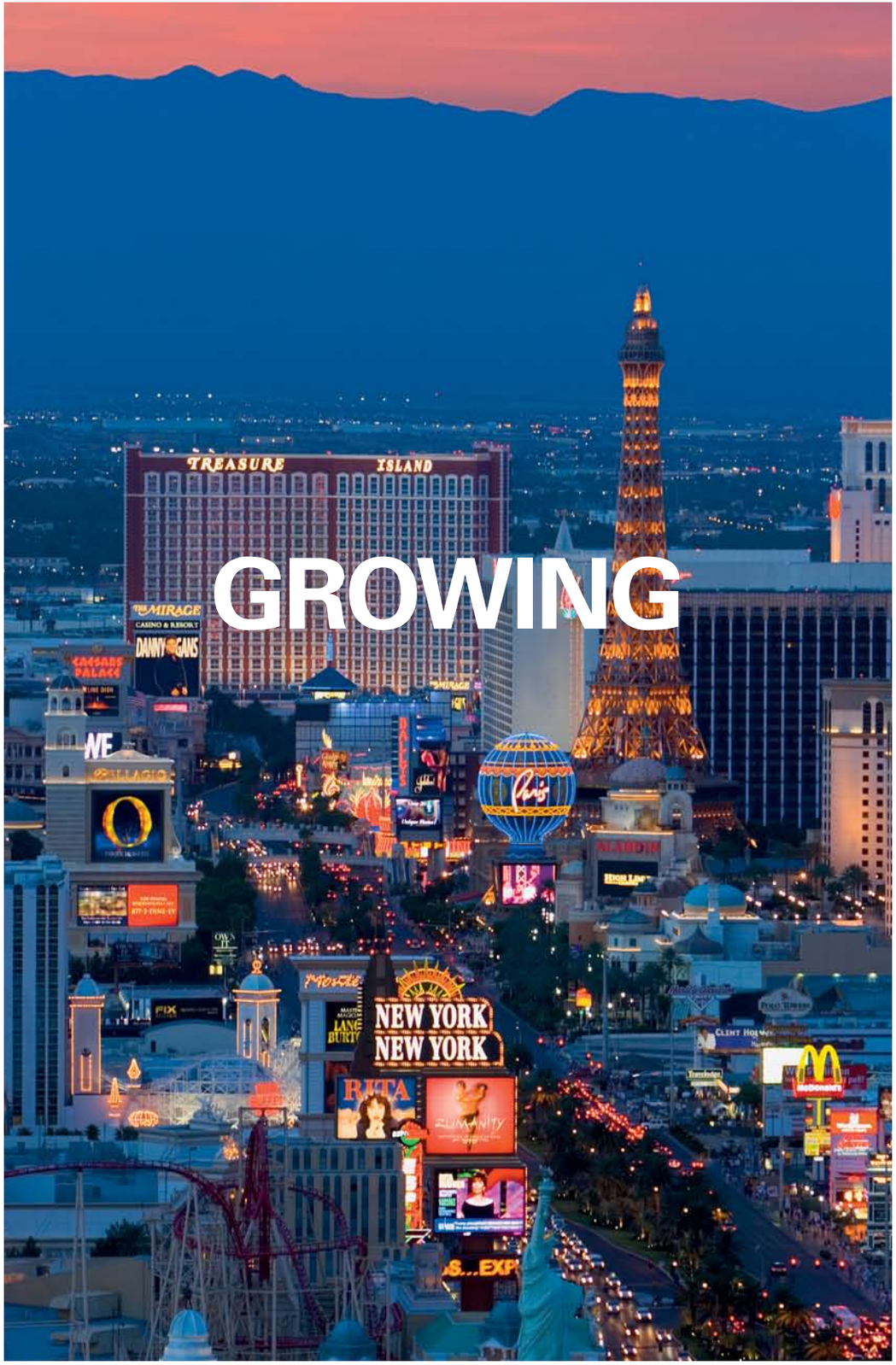

*Primarily based on natural gas

## A NEW GENERATION OF POWER PLANTS

SIERRA PACIFIC RESOURCES' BALANCED ENERGY SUPPLY STRATEGY CALLS FOR INVESTMENT IN NEW, HIGHLY EFFICIENT POWER GENERATION. THE NEW TRACY COMBINED CYCLE PLANT NEAR RENO, SHOWN ON THE OPPOSITE PAGE, IS EXPECTED TO BE GENERATING ELECTRICITY FOR SIERRA PACIFIC POWER'S CUSTOMERS BY THE SUMMER OF 2008. THIS 541-MEGAWATT, NATURAL GAS-FIRED POWER PLANT WILL INCREASE THE UTILITY'S GENERATING CAPACITY BY ABOUT 50 PERCENT, MAKING OUR NORTHERN NEVADA SERVICE AREA VIRTUALLY ENERGY SELF-SUFFICIENT. THE PLANT WILL BE THE MOST EFFICIENT IN NORTHERN NEVADA, USING ABOUT ONE-THIRD LESS FUEL THAN THE COMPANY'S EXISTING GENERATING UNITS AND IT WILL USE VERY LITTLE WATER. NEVADA POWER PLANS TO CONSTRUCT A SIMILAR 500-MEGAWATT, GAS-FIRED COMBINED CYCLE POWER PLANT NORTH OF LAS VEGAS. ADDITIONALLY, TO PROVIDE MORE NEVADA-BASED GENERATING PLANTS FOR USE DURING PEAK DEMAND PERIODS, NEVADA POWER IS INSTALLING GAS-FUELED COMBUSTION TURBINES AT CLARK STATION THAT ARE CAPABLE OF GENERATING UP TO 600 MEGAWATTS. ONCE THESE CLARK STATION UNITS ARE COMPLETED, BY THE END OF SUMMER 2008, WE WILL HAVE MORE THAN DOUBLED OUR COMPANY-OWNED GENERATING CAPACITY IN NEVADA FOR NEVADANS.








# GROWING

Financial Highlights

| (dollars in thousands, except per share information) | 2007 | 2006 |
|---|---|---|
| TOTAL OPERATING REVENUES | $3,600,960 | $3,355,950 |
| TOTAL OPERATING EXPENSES | $3,186,393 | $2,867,153 |
| NET INCOME APPLICABLE TO COMMON STOCK | $ 197,295 | $ 277,451 |
| NET INCOME APPLICABLE TO COMMON STOCK PER SHARE—BASIC | $ 0.89 | $ 1.33 |
| WEIGHTED AVERAGE COMMON SHARES—BASIC | 222,180,440 | 208,531,134 |
| TOTAL ASSETS | $9,464,750 | $8,832,076 |
| TOTAL ELECTRIC RETAIL SALES (MEGAWATT HOURS) | 30,394,026 | 29,530,239 |
| TOTAL RETAIL GAS SALES (DECATHERMS) | 14,893,000 | 15,058,000 |
| TOTAL ELECTRIC CUSTOMERS | 1,192,000 | 1,168,000 |
| TOTAL GAS CUSTOMERS | 149,000 | 146,000 |

## PROVIDING ENERGY FOR A GROWING STATE

THE WORLD FAMOUS LAS VEGAS STRIP IS GROWING, ALONG WITH THE REST OF NEVADA. DURING 2007, NEVADA REGAINED ITS RANKING AS THE FASTEST GROWING STATE IN THE NATION. THOUSANDS OF NEW HOTEL ROOMS WILL BE COMPLETED IN LAS VEGAS OVER THE NEXT FEW YEARS, BOLSTERING THE CITY'S TOURISM AND CONVENTION BUSINESS. TWO OF THE NEW RESORTS UNDER CONSTRUCTION, MGM MIRAGE'S CITYCENTER AND BOYD GAMING'S ECHELON PROJECT, ARE THE LARGEST PROJECTS IN THE CITY'S HISTORY. DUE TO NEVADA'S GROWTH, PEAK ELECTRIC DEMAND IS EXPECTED TO GROW ANNUALLY BY 250 MEGAWATTS FOR THE NEXT FEW YEARS. IN 2007, NEVADA POWER COMPANY AND SIERRA PACIFIC POWER SET 36,677 ELECTRIC METERS. DURING THE PAST 10 YEARS, SIERRA PACIFIC RESOURCES UTILITIES HAVE INVESTED $1.17 BILLION IN NEW TRANSMISSION LINES. NEVADA POWER HAS CONSTRUCTED 210 MILES OF HIGH VOLTAGE TRANSMISSION LINES TO SERVE SOUTHERN NEVADA. OVER THE SAME PERIOD, SIERRA PACIFIC POWER HAS ADDED 450 MILES OF HIGH VOLTAGE TRANSMISSION LINES IN NORTHERN NEVADA.

Michael W. Yackira, President & Chief Executive Officer

**TO OUR SHAREHOLDERS:**

I AM PLEASED TO REPORT THAT THE PAST YEAR WAS ONE OF THE MOST SUCCESSFUL IN OUR COMPANY'S HISTORY AS WE CONTINUE TO IMPROVE FINANCIAL AND OPERATIONAL RESULTS. OUR MANAGEMENT TEAM AND EMPLOYEES ARE DEDICATED TO CONTINUING THE MOMENTUM. I THANK ALL OF OUR EMPLOYEES FOR THEIR HARD WORK AND DILIGENCE IN ACHIEVING THE POSITIVE RESULTS. AT THE SAME TIME, WE MUST ADDRESS IMPORTANT CHALLENGES FACING OUR COMPANY AND INDUSTRY. ¶ WHILE THIS ANNUAL REPORT POINTS OUT RECENT ACCOMPLISHMENTS, I'D ALSO LIKE TO DISCUSS OUR FUTURE DIRECTION. SIERRA PACIFIC RESOURCES AND ITS UTILITIES ARE TAKING A BALANCED APPROACH TO NEVADA'S ENERGY FUTURE WITH A STRATEGY INTENDED TO ENSURE CLEAN, SAFE AND RELIABLE SERVICE AT REASONABLE AND PREDICTABLE PRICES FOR OUR CUSTOMERS. OUR STRATEGY FOCUSES ON OUR CUSTOMERS, OUR COMMUNITIES AND, OF COURSE, OUR INVESTORS. LET'S EXAMINE THE COMPANY'S 2007 FINANCIAL RESULTS.





Sierra Pacific Resources' consolidated earnings were $197.3 million, or 89 cents per share, for the year ended December 31, 2007, compared with earnings of $277.5 million, or $1.33 per share, in 2006. The 2006 results were higher because of two non-recurring factors: a court ruling that allowed Nevada Power to recover $116.2 million, after tax, for previously disallowed fuel and purchased power costs and a $40.9 million after tax gain on the sale of Sierra Pacific Resources' ownership in the Tuscarora Gas Transmission Company.

Importantly, in the third quarter of 2007, Sierra Pacific Resources resumed dividend payments for the first time since 2002, after an improvement in our credit ratings from Moody's Ratings Service. Our utilities' senior secured debt is now rated investment grade by three of the four leading agencies.

We invested more than $1.2 billion this past year in electric infrastructure and we expect to invest approximately $4 billion over the next three years in order to meet our customers' growing energy needs.

**Serving the Fastest Growing State** The demands on our utilities continue to grow since our state once again is the fastest growing in the nation. Peak electric demand is expected to increase statewide at an annual rate of about 250 megawatts, or approximately 3 percent, over the next few years.

The Las Vegas skyline is dotted with construction cranes as workers build thousands of new hotel rooms for area visitors. Las Vegas Sands recently opened its addition to the Venetian. Wynn Resorts will complete its expansion in 2008. The two largest privately-funded construction projects in the United States, MGM Mirage's CityCenter Project and Boyd Gaming's Echelon Place, are well under way and are the most ambitious in the city's history.

Northern Nevada improvements in downtown Reno and the area's abundant outdoor activities are making the region even more appealing to visitors. Additionally, the northern half of the state enjoys a diverse economy with manufacturing, warehousing and mining.

To meet the challenge of ensuring that there is enough electricity to meet these growing demands, we have a three-part strategy that calls for:

- Increasing our investment in energy efficiency and conservation programs;
- Expanding our renewable energy initiatives and investments; and
- Building new generating plants that use traditional fuels, including natural gas and coal.

This strategy will significantly reduce Nevada's dependence on energy markets, potentially limiting the price fluctuations that our customers have experienced this decade.

**Investing in Energy Efficiency and Conservation** Our company offers a broad range of programs for residential and business customers to help them reduce energy consumption. During 2007, these programs reduced energy usage statewide by more than 250 million kilowatt hours. We expect to invest about $135 million in energy efficiency over the next three years. One of our current programs provides rebates that help make installations of photovoltaic solar panels on homes and businesses

more economical. Nevada is supportive of efficiency and conservation programs in that it allows a return on these types of investments.

**Expanding Our Renewable Energy** By the end of 2007, our state led the nation in the use of both geothermal and solar power per capita. Nevada was one of the first states to adopt a so-called "portfolio standard," requiring that certain amounts of energy production come from renewables. Nevada's current standard is one of the most progressive in the nation and requires that 20 percent of the state's energy must be from renewable energy by 2015. We consider this a floor, not a cap, on renewable energy development in our state.

Our utilities currently purchase nearly 275 megawatts of renewable energy from generating plants located in Nevada and we expect that total to increase to approximately 600 megawatts by 2011.

In southern Nevada, two large-scale solar projects were completed in 2007. The 64-megawatt Nevada Solar One project south of Las Vegas is the largest capacity solar thermal power plant built in the world since 1991. In December 2007, North America's largest solar photovoltaic system, a 14-megawatt facility, was completed at Nellis Air Force Base in Las Vegas.

Sierra Pacific Resources and Renewable Energy Systems Americas are in discussions to develop and invest in Nevada's first large-scale wind energy project in northeastern Nevada. The proposed China Mountain project is expected to generate more than 200 megawatts of electricity. This is the first of many direct investments we plan to make in renewable energy projects.

**New Power Generation for Nevada** While energy efficiency and renewables are integral to our strategy, they cannot by themselves serve the energy needs of our growing state. Our customers expect and deserve to have reliable electricity produced when renewable resources are not available, such as on cloud-covered days when solar projects are not producing. This is why our balanced energy supply strategy calls for investment in power plants fueled by natural gas, renewable resources and coal.

Construction is nearly complete in northern Nevada on a 541-megawatt, natural gas-fired, combined cycle generating plant at the Tracy Power Station near Reno. This will be a highly energy efficient, air cooled facility. With the completion of this project by the summer of 2008, the generating capacity of our northern Nevada service area will be increased by approximately 50 percent, making our service territory virtually energy self-sufficient for the first time.

In southern Nevada, our company has doubled its generating capacity since the beginning of 2006 with the addition of approximately 1,700 megawatts of gas-fired generation, not counting ongoing construction at our Clark Generating Station that will help meet the energy needs of Las Vegas during peak usage periods. The Clark project will use new gas-fueled combustion turbines capable of producing 600 megawatts of electricity, with the first 400 megawatts expected to be on line by this summer.

We also are planning to build a highly energy efficient, 500-megawatt, natural gas-fired combined cycle generating plant at our Harry Allen Station north of Las Vegas. If approved by regulators, it could be completed by the summer of 2011.

Our generating fleet is fueled primarily by natural gas, and because gas is vulnerable to major price fluctuation, we plan to diversify our energy portfolio with renewable energy and coal. The proposed





Ely Energy Center in eastern Nevada will initially consist of two 750-megawatt, coal-fired generating units and a 250-mile transmission line that will interconnect for the first time the electric systems serving northern and southern Nevada.

The Ely Energy Center will be the cleanest coal-fired power plant in the nation and once completed will allow us to shut down older, less efficient generating units in southern Nevada, resulting in a net reduction in greenhouse gas emissions. Importantly, the planned transmission line will facilitate the development of renewable energy.

Because of delays in permitting, the first generating unit at the Ely Energy Center will not be operational as soon as was originally planned and for that reason we have accelerated the construction schedule for the Harry Allen gas plant.

As stewards of our state's resources, it is incumbent upon us to care for our environment and we are mindful of that with our balanced approach to serving customer needs. As I mentioned earlier, we remain dedicated to providing clean, safe and reliable service at reasonable and predictable prices and we are convinced that our three-part strategy will allow us to deliver on this commitment.

**Organizational Changes** Glenn C. Christenson, retired executive vice president and chief financial officer of Station Casinos, Inc., was elected to the company's Board of Directors. As a long-time business and civic leader in southern Nevada, Glenn's experience and knowledge will be valuable in helping guide our company in the years ahead.

Tony F. Sanchez III joined the company as successor to Donald "Pat" Shalmy as corporate senior vice president, public policy and external affairs. Tony was a partner in the Nevada law firm of Jones Vargas, where he concentrated on utility matters and government relations. Pat, who retired on February 29, 2008, served our company well and I thank him for his service.

And finally, I'd like to acknowledge and thank Walter Higgins, our chairman of the board, who retired as chief executive officer of our company on August 1, 2007. His tenacity and intellect moved the company from distress to success during very difficult times. We all appreciate his standards of excellence and I continue to value his counsel.

In closing, I'd like to thank you, our shareholders, for your continuing support. We've accomplished a lot and there is a lot more to do. I am looking forward to working with our strong management team to lead this company in achieving better and better results in 2008 and beyond.

Sincerely,

**Michael W. Yackira**
President & Chief Executive Officer

March 19, 2008

## BOARD OF DIRECTORS

Front, left to right: Brian J. Kennedy, Michael W. Yackira, Krestine M. Corbin, Donald D. Snyder, Mary Lee Coleman, Walter M. Higgins, Theodore J. Day; Back, left to right: Clyde T. Turner, Philip G. Satre, Jerry E. Herbst, Joseph B. Anderson, Jr., Glenn C. Christenson, John F. O'Reilly

**Joseph B. Anderson, Jr.**
Chairman and CEO of TAG Holdings, LLC, a parent corporation for various manufacturing and service-based enterprises

**Glenn C. Christenson**
Managing Director Velstand Investments, LLC, retired executive vice president and chief financial officer of Station Casinos, Inc.

**Mary Lee Coleman**
President of Coleman Enterprises, a developer of shopping centers and industrial parks

**Krestine M. Corbin**
President and Chief Executive Officer of Sierra Machinery Incorporated, a machine tool manufacturing company

**Theodore J. Day**
Chairman of Dacole Company, an investment firm; former Senior Partner of Hale, Day, Gallagher Company, a real estate brokerage and investment firm

**Jerry E. Herbst**
Chief Executive Officer of Terrible Herbst, Inc., a gaming, resort and gasoline retail company

**Walter M. Higgins**
Chairman of Sierra Pacific Resources; retired Chief Executive Officer of Sierra Pacific Resources

**Brian J. Kennedy**
President and Chief Executive Officer of Argonaut, LLC; past Chairman of Meridian Gold, Inc.; past President and Chief Operating Officer of FMC Gold Company

**John F. O'Reilly**
Chairman and Chief Executive Officer of the law firm of O'Reilly Law Group LLC and John F. O'Reilly, APC; and Chairman and an Officer and/or Board member of various family-owned business entities and related investments and businesses

**Philip G. Satre**
Retired Chairman of the Board, Harrah's Entertainment, Inc., a gaming entertainment company

**Donald D. Snyder**
Retired President and Board member of Boyd Gaming Corporation, a gaming entertainment company

**Clyde T. Turner**
Owner and Manager of Turner Investments, Ltd., a general-purpose investment company; co-owner of Global Trust Ventures, LLC, a private equity fund; and co-owner of Global Trust Ventures Management, LLC

**Michael W. Yackira**
President and Chief Executive Officer of Sierra Pacific Resources





## SENIOR OFFICERS

Front, left to right: Tony F. Sanchez, III, Michael W. Yackira, Stephen R. Wood; Back, left to right: Paul J. Kaleta, Donald L. "Pat" Shalmy, Roberto R. Denis, Jeffrey L. Ceccarelli, William D. Rogers

**Michael W. Yackira**
President and Chief Executive Officer

**Donald L. "Pat" Shalmy**
Corporate Senior Vice President, Policy & External Affairs; President, Nevada Power Company

**Jeffrey L. Ceccarelli**
Corporate Senior Vice President, Service Delivery & Operations; President, Sierra Pacific Power Company

**Roberto R. Denis**
Corporate Senior Vice President, Energy Supply

**Paul J. Kaleta**
Corporate Senior Vice President, General Counsel and Corporate Secretary

**Stephen R. Wood**
Corporate Senior Vice President, Administration

**William D. Rogers**
Corporate Senior Vice President, Chief Financial Officer and Treasurer

**Tony F. Sanchez, III**
Corporate Senior Vice President

## SHAREHOLDER INFORMATION

**Annual Report on Form 10-K**
The SEC Annual Report on Form 10-K is available free of charge by written request to the company's corporate headquarters or can be downloaded from the company's website: www.sierrapacificresources.com

Address request to:
Shareholder Relations
Sierra Pacific Resources
P.O. Box 30150
Reno, Nevada 89520-3150

**CEO/CFO Certifications**
The most recent certifications by our Chief Executive Officer and Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 are filed as exhibits to our Form 10-K. We have also filed with the New York Stock Exchange the most recent Annual CEO Certification as required by Section 303A.12(a) of the New York Stock Exchange Listed Company Manual.

**Independent Registered Public Accounting Firm**
Deloitte & Touche LLP
Reno, Nevada

**Analyst Contact**
Britta Carlson
Sierra Pacific Resources
Investor Relations
P.O. Box 98910
Las Vegas, Nevada 89151-0001
(702) 367-5624

**NYSE Symbol**
Sierra Pacific Resources' common stock is traded on the New York Stock Exchange under the symbol SRP.

**Stock Transfer Agent and Registrar**
For shareholder records, dividend disbursement information, general inquiries, and address changes contact our Transfer Agent.

Telephone inquiries may be made to a Wells Fargo Shareowner Services representative at (877) 778-6783 (toll free) or (651) 450-4063 between 7:00 a.m. and 7:00 p.m. Central Time. In addition, the Wells Fargo automated response system is available 24 hours a day, 7 days a week. Written inquiries can be made to the addresses below:

Wells Fargo Shareowner Services
P.O. Box 64874
St. Paul, Minnesota 55164-0874

Wells Fargo Shareowner Services
161 North Concord Exchange St.
South St. Paul, Minnesota 55075-1139
www.shareowneronline.com

**Common Stock Investment Plan**
Sierra Pacific Resources' Common Stock Investment Plan offers a convenient method of investing common stock dividends and/or making optional cash investments to purchase additional shares of common stock directly from the company. For more information and to access the prospectus, visit www.sierrapacificresources.com.

*This report was printed on recycled paper and in a smaller format to reduce paper consumption. In addition, fewer copies were printed than in past years because shareholders can access the report on line.

# UNITED STATES
# SECURITIES AND EXCHANGE COMMISSION

**Washington, D.C. 20549**

# FORM 10-K

## ANNUAL REPORT PURSUANT TO SECTION 13 OR 15 (d) OF THE SECURITIES EXCHANGE ACT OF 1934

**For the fiscal year ended December 31, 2007**

| Commission File Number | Registrant, Address of Principal Executive Offices and Telephone Number | I.R.S. Employer Identification Number | State of Incorporation |
|---|---|---|---|
| **1-08788** | **SIERRA PACIFIC RESOURCES**<br>**P.O. Box 30150 (6100 Neil Road)**<br>**Reno, Nevada 89520-3150 (89511)**<br>**(775) 834-4011** | **88-0198358** | **Nevada** |
| **2-28348** | **NEVADA POWER COMPANY**<br>**6226 West Sahara Avenue**<br>**Las Vegas, Nevada 89146**<br>**(702) 367-5000** | **88-0420104** | **Nevada** |
| **0-00508** | **SIERRA PACIFIC POWER COMPANY**<br>**P.O. Box 10100 (6100 Neil Road)**<br>**Reno, Nevada 89520-0024 (89511)**<br>**(775) 834-4011** | **88-0044418** | **Nevada** |

| (Title of each class) | (Name of exchange on which registered) |
|---|---|
| **Securities registered pursuant to Section 12(b) of the Act:** | |
| **Securities of Sierra Pacific Resources:** | |
| **Common Stock, $1.00 par value** | **New York Stock Exchange** |
| **7.803% Senior Notes Due 2012** | **New York Stock Exchange** |

**Securities registered pursuant to Section 12(g) of the Act:**

**Securities of Nevada Power Company:**

**Common Stock, $1.00 stated value**

**Securities of Sierra Pacific Power Company:**

**Common Stock, $3.75 par value**

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act:

Sierra Pacific Resources Yes ☒ No ☐ Nevada Power Company Yes ☐ No ☒ Sierra Pacific Power Company Yes ☐ No ☒

Indicate by check mark if each of the registrants is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ☐ No ☒

Indicate by check mark whether each of the registrants (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☒ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrants' knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☒

Indicate by check mark whether any registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. (See definition of "large accelerated filer", "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act).

| | | | | |
|---|---|---|---|---|
| Sierra Pacific Resources: | Large accelerated filer ☒ | Accelerated filer ☐ | Non-accelerated filer ☐ | Smaller reporting company ☐ |
| Nevada Power Company: | Large accelerated filer ☐ | Accelerated filer ☐ | Non-accelerated filer ☒ | Smaller reporting company ☐ |
| Sierra Pacific Power Company: | Large accelerated filer ☐ | Accelerated filer ☐ | Non-accelerated filer ☒ | Smaller reporting company ☐ |

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ☐ No ☒ (Response applicable to all registrants).

State the aggregate market value of Sierra Pacific Resources' common stock held by non-affiliates. As of June 30, 2007: $ 3,891,381,447

Indicate the number of shares outstanding of each of the issuer's classes of Common Stock, as of the latest practicable date.

Common Stock, $1.00 par value, of Sierra Pacific Resources outstanding at February 22, 2008: 233,889,221 Shares

Sierra Pacific Resources is the sole holder of the 1,000 shares of outstanding Common Stock, $1.00 stated value, of Nevada Power Company.

Sierra Pacific Resources is the sole holder of the 1,000 shares of outstanding Common Stock, $3.75 par value, of Sierra Pacific Power Company.

**DOCUMENTS INCORPORATED BY REFERENCE:**

Portions of Sierra Pacific Resources' definitive proxy statement to be filed in connection with the annual meeting of shareholders, to be held April 28, 2008, are incorporated by reference into Part III hereof.

This combined Annual Report on Form 10-K is separately filed by Sierra Pacific Resources, Nevada Power Company and Sierra Pacific Power Company. Information contained in this document relating to Nevada Power Company is filed by Sierra Pacific Resources and separately by Nevada Power Company on its own behalf. Nevada Power Company makes no representation as to information relating to Sierra Pacific Resources or its subsidiaries, except as it may relate to Nevada Power Company.

Information contained in this document relating to Sierra Pacific Power Company is filed by Sierra Pacific Resources and separately by Sierra Pacific Power Company on its own behalf. Sierra Pacific Power Company makes no representation as to information relating to Sierra Pacific Resources or its subsidiaries, except as it may relate to Sierra Pacific Power Company.

## EXPLANATORY NOTE

This document is a composite of the Company's original Form 10-K filed on February 27, 2008, and an amendment thereto on Form 10-K/A filed on February 28, 2008. The amendment corrected certain printer's errors in the original filing, which related solely to dates in Items 8 and 9A(T), and certain exhibits.

**SIERRA PACIFIC RESOURCES**
**NEVADA POWER COMPANY**
**SIERRA PACIFIC POWER COMPANY**
**ANNUAL REPORT ON FORM 10-K**

## CONTENTS

## FORWARD LOOKING STATEMENTS

The discussion of forward looking statements in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, is incorporated herein by reference.

## PART I

### ITEM 1. BUSINESS

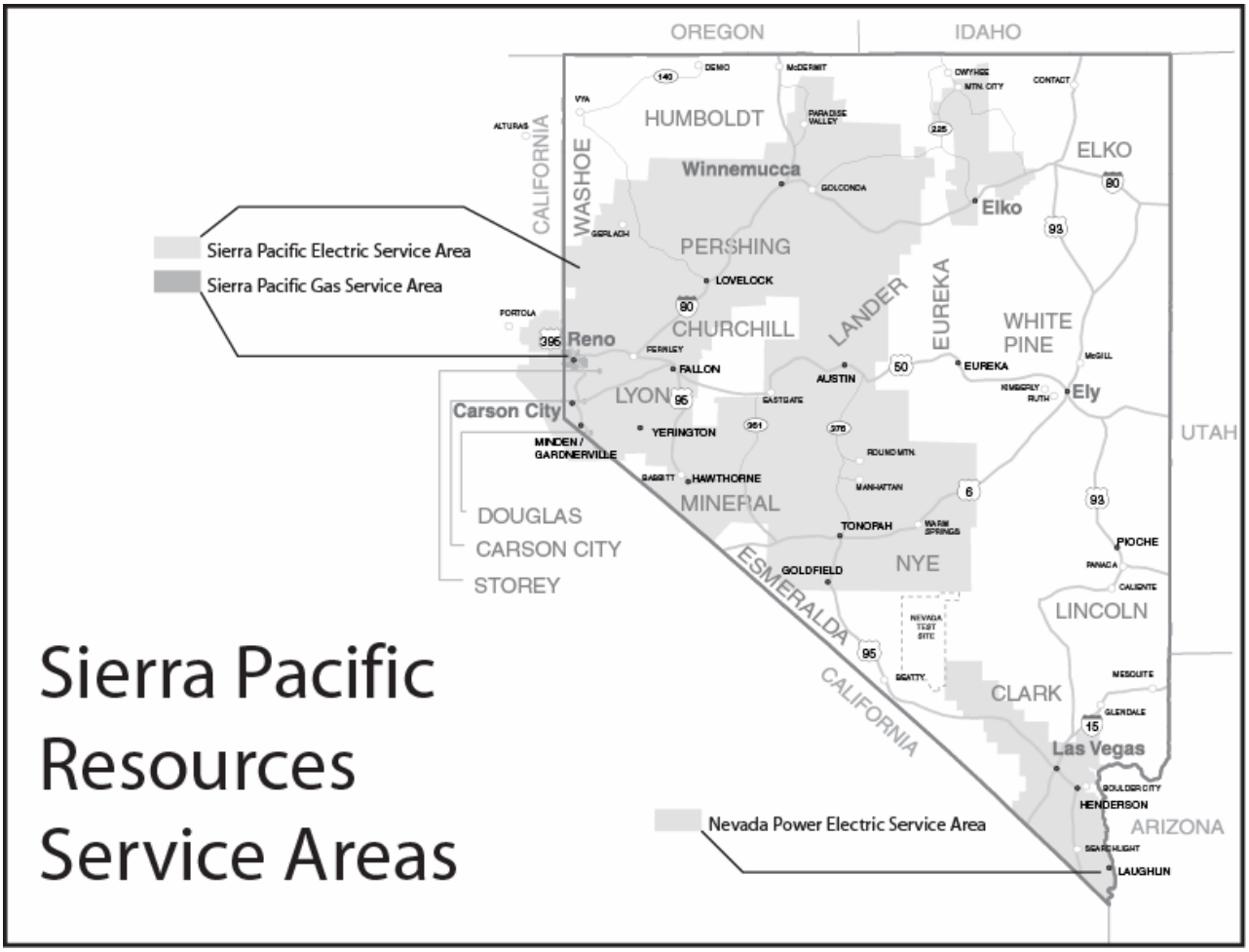
### SIERRA PACIFIC RESOURCES

Sierra Pacific Resources (SPR) is an investor-owned holding company that was incorporated under Nevada law on December 12, 1983. The company's stock is traded on the New York Stock Exchange under the symbol "SRP". SPR's mailing address is P.O. Box 30150 (6100 Neil Road), Reno, Nevada 89520-3150 (89511).

SPR has six primary, wholly-owned subsidiaries: Nevada Power Company (NPC), Sierra Pacific Power Company (SPPC), Tuscarora Gas Pipeline Company (TGPC), Sierra Pacific Communications (SPC), Sierra Pacific Energy Company (SPE), and Lands of Sierra (LOS). References to SPR refer to the consolidated entity, except where the context provides otherwise. NPC and SPPC are referred to collectively in this report as the "Utilities".

The Utilities operate three business segments, as defined by FASB Statement No. 131, *Disclosure about Segments of an Enterprise and Related Information*: NPC electric; SPPC electric; and SPPC natural gas. Electric service is provided to Las Vegas and surrounding Clark County, northern Nevada and the Lake Tahoe area of California. Natural gas service is provided in the Reno-Sparks area of Nevada. The Utilities are the major contributors to SPR's financial position and results of operations. Other subsidiaries either do not meet the definition of a segment or are below the quantitative threshold for separate segment disclosure and are combined under "all other" in the following pages. Parenthetical references are included after each major section title to identify the specific entity or entities addressed in the section. See Note 2, Segment Information of the Notes to Financial Statements, for further discussion.

NPC and SPPC service territories are as follows:



The Utilities provide electric and natural gas services to a diverse mix of over one million residential, commercial, industrial and public sector customers. Major industries served include gaming/recreation, mining, warehousing/manufacturing, offices, health care, education, military bases and other governmental entities. The Utilities' revenues and operating income are subject to fluctuations during the year due to the impacts that seasonal weather, rate changes and customer usage patterns have on demand for electric energy and services. NPC is a summer peaking utility, experiencing its highest retail energy sales in response to the demand for air conditioning. SPPC's electric system peak also occurs in the summer, with a slightly lower peak demand in the winter. SPPC's gas business typically peaks in the winter months due to heating demands.

Beginning in 2007, the Utilities embarked on a three part strategy to manage resources against our load by conserving energy, investing in renewable resources and building generation in an effort to reduce reliance on purchased power.

*Conservation Programs*

As part of the Clinton Global Initiative, the Utilities' committed to spending approximately $135 million for the years 2008-2010 towards increasing efficiency and qualified conservation programs. In 2006, NPC obtained budget approval from the Public Utilities Commission of Nevada (PUCN) to implement new and expanded qualified conservation programs (Demand Side Management or "DSM") for the years 2007-2009, and in 2007, SPPC obtained PUCN approval to increase its DSM program for the years 2008-2010. NPC and SPPC have received PUCN approval of approximately $73.6 million and $29.8 million, respectively and an additional $36.9 million is pending PUCN approval as part of NPC's 5$^{th}$ amendement to its Integrated Resource Plan (IRP) for the years 2008- 2010. The PUCN approval of the DSM budget increase was a key step in expanding the energy savings yield from the DSM programs.

NPC and SPPC have designed a portfolio of cost effective DSM programs that allow every customer to take advantage of savings from energy efficiency measures. DSM programs are marketed across all segments of customer classes (residential, commercial, public, and low income).

Furthermore, the Portfolio Standard, discussed below, allows energy efficiency measures from qualified conservation programs to meet up to 25% of the Portfolio Standard. A portfolio energy credit is created for each kilowatt hour (kWh) of energy conserved by qualified energy efficiency programs. Energy saved during peak demand hours earns double the portfolio energy credits. After the DSM percentage allowance is fully utilized, NPC's and SPPC's strategy is to continue to implement cost-effective DSM programs.

*Renewable Resources*

Nevada law sets forth the renewable energy portfolio standard ("Portfolio Standard") requiring providers of electric service to acquire, generate, or save a specific percentage of its total retail energy sales from renewable energy resources (Renewables). Renewables include biomass, geothermal, solar, waterpower and wind projects. Pursuant to the Portfolio Standard, NPC and SPPC were required to obtain nine percent (9%) of their total retail energy sales from Renewables for year 2007. The Portfolio Standard increases by three percent (3%) every other year until it reaches 20% in year 2015. Moreover, not less than five percent (5%) of the total Portfolio Standard must be met from solar resources. Compliance with the Portfolio Standard is measured in portfolio energy credits (PCs) administered by the PUCN. A PC is created for each kWh of renewable energy generated or for each kWh of energy conserved by qualified energy efficiency programs.

Nevada law requires providers of electric services to file an annual report that describes the level of compliance with the Portfolio Standard. In the Utilities' April 2007 Portfolio Standard Annual Report for Compliance Year 2006 (submitted to the PUCN jointly), NPC reported that with PUCN approval of a sale and purchase of SPPC's excess non-solar PCs, NPC met the non-solar Portfolio Standard. SPPC reported compliance with the non-solar component of the Portfolio Standard. However, due to lack of availability, the Utilities did not meet the solar portion of the Portfolio Standard. Additionally, the report described the Utilities ongoing activities to reach full compliance with the Portfolio Standard in the near future.

In December 2007, the PUCN issued its Order accepting the Utilities' Portfolio Standard Annual Report for Compliance Year 2006 and accepted a stipulation that granted an exemption from meeting the Portfolio Standard. In addition, because the Utilities took reasonable efforts to comply with the Portfolio Standard, the PUCN waived any administrative fines or penalties for non compliance.

*Generation*

The Utilities do not own generating facilities sufficient to meet the peak demands and reliability needs of Nevada's growing population and, as a result, NPC is forecasting to purchase approximately 32% of its total system energy needs from the wholesale market and with the addition of the Tracy Generating Station, SPPC is forecasting to purchase approximately 48% of its total system energy needs from the wholesale market for year 2008. For the 2008 summer peak, NPC has secured approximately 98% of its forecasted capacity needs, while SPPC has secured 100% of its forecasted capacity needs.

The amount of power purchased by the Utilities varies from time to time depending on demand, the cost of purchased power compared with our cost of generation, and the availability of such power. In 2007, NPC and SPPC purchased approximately 37.0% and 57.1%, respectively, of total system energy needs. Some purchased power contracts are indexed to natural gas prices. Due to the relatively large seasonal gas and purchased power usage, the Utilities purchase power and hedge a portion of their total natural gas exposure as discussed further in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Energy Supply.

Since 2003, the Utilities have either purchased or completed construction of generating facilities or peaking units with a summer capacity of 1574 MWs. In 2007, NPC began construction of two peaking units at the Clark Station for 619 MWs (nominally rated) and a 500 MW (nominally rated) natural gas fired combined cycle generator at the Harry Allen station. NPC anticipates the completion of the Clark units in 2008 and the Harry Allen Unit in 2011. SPPC is constructing a new 540 MW (nominally rated) facility at the Tracy Generating Station which it anticipates to be completed by mid 2008.

Furthermore, as part of the strategy to grow and invest in, and improve the performance of their regulated businesses, the Utilities announced their intention to develop a major energy project located near Ely, Nevada, which will consist of two 750-megawatt coal fired generation units and includes the construction of a 250-mile transmission line to interconnect the transmission systems of NPC and SPPC. In November 2006, the Public Utilities Commission of Nevada (PUCN) approved NPC's 2006 Integrated Resource Plan (IRP) and SPPC's thirteenth amendment to its 2004 IRP. Included in the PUCN's approval is Phase 1 of the construction of the Ely Energy Center. The PUCN approved spending up to $300 million for development activities associated with Ely Energy Center with a limitation of $155 million placed on expenditures until the Utilities have obtained appropriate air permits. The PUCN approved the Utilities' request to initially allocate Phase 1 costs between NPC and SPPC on an 80/20 split, respectively. The PUCN also required NPC and SPPC to file amendments to their IRPs in early 2008 once elements of the plan, including final costs, can be more accurately estimated. The total project costs are estimated to be approximately $5.0 billion if construction were to begin at the time of this filing. Depending on the timing of construction, negotiation of certain contracts, the potential initiation of any litigation challenging the project, and the timing and terms of permitting, among other factors, actual costs, scope, and timing of the completion of the project will likely differ materially from initial estimates. This project and details discussed above are collectively referred to in this report as the "Ely Energy Center". For further discussion on the details of the Ely Energy Center, see Item 7, Management's Discussion and Analysis, Executive Overview.

As a result of expanded service territory growth, both Utilities have added transmission infrastructure. Discussions of new transmission lines are in NPC's and SPPC's respective Transmission sections below.

Nevada state law allows, with PUCN approval, commercial customers with an average annual load of one MW or more, to choose alternate energy suppliers. In addition, some large customers may own and operate generation facilities to meet their own energy requirements. One large SPPC mining customer began operating a 118 MW generating facility in December of 2005 and another large SPPC mining customer has begun construction of a 203 MW facility with an anticipated in service date in 2008. These matters are discussed further under Competition for NPC and SPPC below.

The Federal Energy Regulatory Commission (FERC), PUCN and, in the case of SPPC, the California Public Utilities Commission (CPUC) regulate portions of the Utilities' accounting practices and electricity and natural gas rates. The FERC regulates the terms and prices of transmission services and sales of wholesale electricity. The PUCN and CPUC have authority over general and energy rates charged to retail customers, the issuance of securities and transactions with affiliated parties.

Periodic reports on Form 10-K and Form 10-Q and current reports on Form 8-K are made available to the public, free of charge, on SPR's, NPC's and SPPC's websites (www.sierrapacificresources.com, www.nevadapower.com, and www.sierrapacific.com) through links on these websites to the SEC's website at www.sec.gov, as soon as reasonably practicable after they have been filed with the SEC. The contents of the above referenced website addresses are not part of this Form 10-K. The public may also read any copy of materials filed with the SEC by SPR, NPC or SPPC at the SEC's Public Reference Room at 100 F Street, NE, Washington, D.C. 20549. Information on the operation of the Public Reference Room may be obtained by calling the SEC at 1-(800) SEC-0030. Reports, proxy and information statements, and other information regarding issuers that file electronically may also be obtained directly from the SEC's website. Available on the sierrapacificresources.com website are the code of ethics for the chief executive officer, chief financial officer and controller, charters for the Audit, Compensation and Nominating and Governance Committees of SPR's Board of Directors and our corporate governance and standards of conduct guidelines. Printed copies of these documents may be obtained free of charge by writing to SPR's Corporate Secretary at Sierra Pacific Resources, P.O. Box 30150, Reno, NV 89520-3150.

## NEVADA POWER COMPANY

NPC is a Nevada corporation organized in 1921 and, by itself and through a predecessor corporation, has been providing electric services to southern Nevada since 1906. NPC became a subsidiary of SPR in July 1999. Its mailing address is 6226 West Sahara Avenue, Las Vegas, Nevada 89146.

Nevada Electric Investment Company (NEICO) is a wholly-owned subsidiary of NPC. NEICO is a 25% member of Northwind Aladdin, LLC, which operates the central energy plant at the Aladdin Resort and Casino in Las Vegas. The other 75% is owned by Macquarie Infrastructure Company Trust.

**Business and Competitive Environment**

*Overview*

NPC is a public utility that generates, transmits and distributes electric energy in southern Nevada. At year-end 2007, NPC served approximately 826,000 customers in Las Vegas, North Las Vegas, Henderson, Searchlight, Laughlin, and adjoining areas, including Nellis Air Force Base and the Department of Energy's Nevada Test Site in Nye County.

*Electric Operations*

NPC is charged with meeting the growing electric energy needs of the residential population and expanding business and public sectors in Southern Nevada. In addition to customer growth, demand and resulting revenues are impacted by rate changes, seasonal or atypical weather and customer use. NPC's peak demand occurs in the summer. Therefore, NPC's revenues and associated expenses are not incurred or generated evenly throughout the year.

To serve its customer base, NPC purchases power and generates electricity in accordance with an Energy Supply Plan, as discussed in more detail later in this section and in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Energy Supply. In 2007 in a continued effort to reduce reliance on purchased power, NPC began the construction of 619 MWs (nominally rated) peaking units at Clark Station which are scheduled to be completed in 2008. Additionally, NPC began construction of a 500 MW (nominally rated) unit at Harry Allen which is scheduled to be completed in 2011.

Nevada regulations require NPC to file general rate cases (GRCs) every three years with the PUCN to adjust rates including cost of service and return on investment. Nevada state regulations also require NPC to file annual deferred energy accounting adjustment applications to either recover or refund balances that have been deferred and that represent the difference between fuel and purchased power costs actually incurred and the amounts collected in current retail rates. Additionally, NPC is required quarterly to file rate cases to reset Base Tariff Energy Rates (BTER), reflecting more current fuel and purchased power costs. Rate cases are discussed in more detail in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Regulatory Proceedings, and Note 3**,** Regulatory Actions, of the Notes to Financial Statements.

The FERC has jurisdiction under the Federal Power Act with respect to wholesale rates, service, interconnection, accounting, and other matters in connection with NPC's sale of electricity for resale and interstate transmission. The FERC also has jurisdiction over the natural gas pipeline companies from which NPC takes natural gas for fuel.

*Competition*

State law allows commercial customers with an average annual load of 1 MW or more to file a letter of intent and application with the PUCN to acquire electric energy, capacity, and ancillary services from another provider. The law requires customers wishing to choose a new supplier to receive the approval of the PUCN and meet public interest standards. In particular, departing customers must secure new energy resources that are not under contract to NPC, the departure must not burden NPC with increased costs or cause any remaining customers to pay increased costs, and the departing customers must pay their portion of any deferred energy balances. The PUCN adopted regulations prescribing the criteria that will be used to determine if there will be negative impacts to remaining customers or to NPC. Customers wishing to choose a new supplier must provide 180-day notice to NPC. NPC would continue to provide transmission, distribution, metering, and billing services to such customers. Management believes that those customers securing energy from new energy suppliers would reduce NPC's need to purchase power from potentially volatile wholesale energy markets.

Currently, there are no material applications pending with the PUCN to exit the system in NPC's service territory.

**Sales**

In 2007, NPC's operating revenues were approximately $2.4 billion. Summer peak loads are driven by air conditioning demand. Winter peak loads are low relative to the summer peak. Winter load above the base amount is driven by air handling in forced air furnaces. NPC's peak load increased at an average annual growth rate of 4.7% over the past five years, reaching 5,866 MW in July 2007. NPC's retail total electric megawatt-hour (MWh) sales have increased at an average annual growth rate of 3.8% over the past five years.

NPC's electric customers by class contributed the following toward 2007, 2006 and 2005 MWh sales:

| | MWH Sales (Billed and Unbilled) | | | | | |
|---|---|---|---|---|---|---|
| | 2007 | | 2006 | | 2005 | |
| | MWh | % of Total | MWh | % of Total | MWh | % of Total |
| Residential | 9,371,726 | 42.4% | 9,033,142 | 42.3% | 8,288,309 | 41.3% |
| Commercial & Industrial: | | | | | | |
| Gaming/Recreation/Restaurants | 3,697,324 | 16.7% | 3,736,608 | 17.5% | 3,711,790 | 18.5% |
| All Other Retail | 8,551,874 | 38.7% | 8,049,753 | 37.7% | 7,454,595 | 37.1% |
| Total Retail | 21,620,924 | 97.8% | 20,819,503 | 97.5% | 19,454,694 | 96.9% |
| Wholesale | 240,934 | 1.1% | 244,128 | 1.2% | 278,527 | 1.4% |
| Sales to Public Authorities | 252,119 | 1.1% | 281,369 | 1.3% | 349,912 | 1.7% |
| Total | 22,113,977 | 100.0% | 21,345,000 | 100.0% | 20,083,133 | 100.0% |

Growth in NPC's residential class sales continues primarily as a result of new home construction in Las Vegas and the surrounding areas. According to the Southern Nevada Home Builders Association, new home sales in the Las Vegas area in 2007 totaled 15,468, compared with 36,051 for 2006.

The decline in MWhs for gaming/recreation/restaurants in 2007 from 2006 was primarily due to the closure of one major casino. According to the Center for Business and Economic Research, at the University of Nevada Las Vegas, the number of hotel rooms in Las Vegas grew by 4,185 rooms or 3.2% in 2007 for a total of 136,790. However, the majority of the rooms were not added until late in 2007. The expected room growth rate for 2008 is 3.8% and 15.8% for 2009. The significant increase in room growth for 2009 is primarily due to the scheduled completion of Project City Center, which is expected to add over 6,000 rooms. Tourism and gaming remain southern Nevada's leading industries and together comprise one of NPC's largest classes of customers. Management believes that room growth rate is a key economic indicator for the Las Vegas area.

All other retail, which includes such industries as construction, education, health care and manufacturing, continued to see increases in response to population growth in the Las Vegas area.

## Demand

### *Load and Resources Forecast*

NPC's integrated peak electric demand rose from 5,623 MW in 2006 to 5,866 MW in 2007. Variations in energy usage occur as a result of varying weather conditions, economic conditions, and other energy usage behaviors, such as conservation efforts. This necessitates a continual balancing of loads and resources, and requires both purchases and sales of energy under short and long term contracts and the prudent management and optimization of available resources.

NPC plans to meet its customers' needs through a combination of company-owned-generation and purchased power. See the Generation section and Purchased Power section for details of NPC's generation and contracts for purchased power. Remaining needs will be met through power purchases through RFPs or short term purchases.

Below is a table summarizing the forecasted summer electric capacity requirement and resource needs of NPC (assuming no curtailment of supply or load, and normal weather conditions):

| | Forecasted Electric Capacity Requirements and Resources (MW) | | | | |
|---|---|---|---|---|---|
| | 2008 | 2009 | 2010 | 2011 | 2012[4] |
| Total Requirements [1] | 6,654 | 6,950 | 7,195 | 7,410 | 7,617 |
| Resources: | | | | | |
| Company-owned existing generation | 2,863 | 2,863 | 2,863 | 2,743 | 2,743 |
| Company-owned new generation [2] | 413 | 619 | 619 | 1,093 | 1,093 |
| Contracts for power purchases [3] | 3,236 | 2,511 | 1,911 | 1,911 | 2,064 |
| Total Resources | 6,512 | 5,993 | 5,393 | 5,747 | 5,900 |
| Total Additional Required [5] | 142 | 957 | 1,802 | 1,663 | 1,717 |

(1) Includes system peak load plus planning reserves.
(2) Includes 413 MW of the Clark peaking unit operational in 2008, 206 MWs of the Clark peaking units available in the 2009 summer peaking capacity, and a 474 MW combined cycle unit at the Harry Allen Plant in 2011.
(3) Assumes a 570 MW long-term summer contract commencing in 2008, which is currently pending approval by the PUCN.
(4) Does not include the Ely Energy Center, as the Ely Energy Center is not expected to be operational prior to year end 2012.
(5) Total Additional required is the difference between the total requirements and Total resources. Total Additional Required represents the amount needed to achieve the forecasted system peak plus a planning reserve margin.

## Energy Supply

The energy supply function at NPC encompasses the reliable and efficient operation of NPC's owned generation, the procurement of all fuels and purchased power, and resource optimization.

NPC faces energy supply challenges for its load control area. There is the potential for continued price volatility in NPC's service territory, particularly during peak periods. A greater dependence on gas-fired generation in the region subjects power prices to gas price volatilities. NPC faces load obligation uncertainty due to the potential for customer switching. Some counterparties in these areas have significant credit difficulties, representing credit risk to NPC.

In response to these energy supply challenges, NPC has adopted an approach to managing the energy supply function that has three primary elements. The first element is a set of management guidelines that relate 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 a clear distinction between policy setting (or planning) and execution. Lastly, NPC will continue to pursue a process of ongoing regulatory involvement and acknowledgement of the resource portfolio management plans. Details of the Energy Supply function are discussed in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Energy Supply.

### *Total System*

NPC manages a portfolio of energy supply options. The availability of alternate resources allows NPC to dispatch its electric generation system in a more cost-effective manner under varying operating and fuel market conditions while maintaining system integrity. During 2007, NPC generated approximately 63% of its total system requirements, purchasing the remaining 37% as shown below.

| | 2007 | | 2006 | | 2005 | |
|---|---|---|---|---|---|---|
| | MWh | % of Total | MWh | % of Total | MWh | % of Total |
| NPC Company Generation | | | | | | |
| Gas/Oil | 10,437,115 | 45.3% | 8,093,020 | 36.1% | 2,465,064 | 11.7% |
| Coal | 4,083,262 | 17.7% | 4,067,209 | 18.2% | 5,629,139 | 26.8% |
| Total Generated | 14,520,377 | 63.0% | 12,160,229 | 54.3% | 8,094,203 | 38.6% |
| Total Purchased | 8,510,429 | 37.0% | 10,248,394 | 45.7% | 12,894,382 | 61.4% |
| Total System | 23,030,806 | 100.0% | 22,408,623 | 100.0% | 20,988,585 | 100.0% |

As a supplement to its own generation, NPC purchases spot, short-term firm, intermediate-term firm, long-term firm, and non-firm energy to meet its customer demand requirements. Total energy supply includes purchases from outside the electric system due to limited control area generation and also the need to access market energy supplies. NPC's decision to purchase this energy is based on economics, mitigation of availability risk, and system import limits. Firm block purchases are transacted as both a price hedging strategy and to ensure that needed firm capacity is available over peak load periods. Spot market energy is purchased based on the economics of purchasing "as-available" energy when it is less expensive than NPC's own generation, again, subject to net system import limits. NPC's 2007 company generated MWhs increased 19.4% from NPC's 2006 company generated MWhs. The increase in NPC's 2007 company generated MWhs is mainly due to the availability of the Lenzie generating units available for the entire year as compared to 2006 when block 1 and 2 became commercially available during January and April of 2006, respectively. NPC's 2007 purchased power MWhs decreased 17% from NPC's 2006 purchased power MWhs. See Energy Supply in Management's Discussion and Analysis of Financial Condition and Results of Operations for additional information regarding NPC's purchasing strategies.

***Risk Management***

See Item 7A, Quantitative and Qualitative Disclosures About Market Risk.

***Generation***

NPC's generation capacity consists of a combination of 29 gas, oil and coal generating units with a combined summer capacity of 3,276 MWs as described in Item 2, Properties. In 2007, NPC generated approximately 63% of its total system requirements.

In November 2006, the PUCN approved Phase 1 of the construction of the Ely Energy Center. The Ely Energy Center consists of two 750-megawatt coal fired generation units. The plan also includes further expansion possibilities involving two 500 MW coal gasification units when the technology becomes commercially viable. See discussion of Ely Energy Center earlier, under SPR.

NPC filed its 2006 Integrated Resource Plan (IRP) with the PUCN, pursuant to which the company received approval to commence construction of peaking units at Clark Station. The first 413 MW (nominally rated) of the Clark peaking units have a scheduled in-service date of June 2008 and the remaining 206 MW(nominally rated) are scheduled to be operational in 2008, but are beyond NPC's summer peaking period. In 2007, NPC began construction of a 500 MW (nominally rated) combined cycle unit at the existing Harry Allen site with a commercial operation date prior to summer of 2011. NPC expects to file an amendment to its 2006 IRP with the PUCN in March 2008 seeking approval of this project. These additional units will reduce NPC's reliance on purchased power.

***Fuel Availability***

NPC's 2007 fuel requirements for electric generation were provided by natural gas, coal, and oil. The average costs of gas, coal, and oil for energy generation per million British thermal units (MMBtu) for the years 2003 through 2007, along with the percentage contribution to NPC's total fuel requirements were as follows:

Average Consumption Cost & Percentage Contribution to Total Fuel Requirement

| | Gas | | Coal | | Oil | |
|---|---|---|---|---|---|---|
| | $/MMBtu | Percent | $/MMBtu | Percent | $/MMBtu | Percent |
| 2007 | 6.32 | 64.4% | 1.89 | 35.6% | 17.17 | 0.0% |
| 2006 | 7.40 | 58.8% | 1.63 | 41.1% | 16.66 | 0.1% |
| 2005 | 6.18 | 32.7% | 1.59 | 67.1% | 13.50 | 0.1% |
| 2004 | 6.13 | 27.3% | 1.33 | 72.6% | 8.75 | 0.1% |
| 2003 | 5.70 | 40.9% | 1.41 | 59.0% | 5.28 | 0.1% |

For a discussion of the change in fuel costs, see Results of Operations in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations.

Natural gas supplies are procured one season ahead of use through a competitive bidding process. The physical gas prices are set at an appropriate industry index during the month of current delivery. All natural gas is delivered to NPC through the use of firm gas transport contracts. Monthly and daily gas supply adjustments are made by Gas Trading personnel based on the current energy marketplace. NPC continues to optimize the use of Lenzie and Silverhawk generating facilities which results in a reduction of NPC's exposure to fluctuations in the market price of gas. These units are more efficient than most generating facilities supplying energy to

the market in which NPC purchases energy and, consequently, will require less fuel to produce the same amount of electric energy. This trend is expected to continue in 2008 and beyond.

Coal delivered to the Reid Gardner Station originates from various mines in the Utah and Colorado coal fields and is delivered to the station via the Union Pacific Railroad. NPC has long term contracts with Arch Coal Company (expires 2011) and Andalex Resources, Inc. (expires 2010). Long term contracts are expected to be executed in 2008 by NPC with Co-op Mining Co. (expires 2012) and Bowie Resources (expires 2012). These contracts are expected to represent 100% of Reid Gardner's projected requirements for 2008, 80% for 2009, 57% for 2010, 40% for 2011 and 27% for 2012.

As of December 31, 2007, Reid Gardner's coal inventory level was 251,960 tons, or approximately 75 days of consumption at 100% capacity.

A transportation services contract with Union Pacific Railroad provides for deliveries from the Provo, Utah interchange as well as various mines in Utah and Colorado, to the Reid Gardner Station in Moapa, Nevada. The Utah Railway contract provides for delivery of all coal not loaded by the Union Pacific in Helper, Utah to interchange with Union Pacific at Provo, Utah. The Utah Railway contract expires on December 31, 2008 and the Union Pacific Railroad contract has been extended through March 31, 2008. Currently, NPC is negotiating a new contract and does not expect any disruption to service.

Coal for the Navajo Station, which is jointly owned and operated by Salt River Project, is obtained from surface mining operations conducted by Peabody Coal Company (Peabody) on portions of the Black Mesa in Arizona within the Navajo and Hopi Indian tribes (the Tribes) reservations. The Navajo supply contract expires June 2011, with an option provided to NPC to extend for an additional 15 years.

***Purchased Power***

NPC, under the guidelines set forth in the NPC Energy Supply Plan, continues to manage a diverse portfolio of contracted and spot market supplies, as well as its own generation, with the objective of minimizing its net average system operating costs. During 2007, NPC purchased 37.0% of its total energy requirements.

NPC purchases both forward firm energy and spot market energy based on economics, operating reserve margins and unit availability. NPC seeks to manage its growing loads efficiently by utilizing its generation resources in conjunction with buying and selling opportunities in the market.

NPC has entered into long term purchase power contracts (3 or more years) with the following counterparties (excluding Qualified Facilities or Renewable Contracts):

| Company Name (Counterparty) | Quantity (MW) | Contract Termination |
|---|---|---|
| State of Nevada, Colorado River Commission | 200 MW | 2017 |
| Nevada Sun Peak Limited Partnership | 222 MW | 2016 |
| Las Vegas Cogeneration II | 224 MW | 2013 |
| Southern Nevada Water Authority | 125 MW | 2013 |
| California Department of Water Resources | 233 MW | 2013 |
| LS Power(1) | 200 MW | 2008 |
| Las Vegas CoGen I(2) | 50 MW | 2017 |
| Dynegy Power Marketing(2) | 570 MW | 2017 |

(1) Expires in April 2008.
(2) Contracts are pending approval by the PUCN.

NPC's credit standing affects the terms under which NPC is able to purchase fuel and electricity in the western energy markets. As a result of NPC's improved credit quality during 2007, NPC was no longer required to provide cash deposits to be held by counterparties for the purchase of fuel and electricity nor to make pre-payments to counterparties for fuel and reduced the number of counterparties requiring modified payment terms from the previous year.

NPC is a member of the Western Systems Power Pool (WSPP) and the Southwest Reserve Sharing Group (SRSG). NPC's membership in the SRSG has allowed it to network with other utilities in an effort to use its resources more efficiently in the sharing of responsibilities for reserves.

*Qualifying Facilities*

Federal regulations, including the Public Utility Regulatory Policies Act of 1978 (PURPA), which were passed to promote renewable and alternative energy resources, and the Energy Policy Act of 2005, set out the requirements for utilities to purchase the output produced by Qualifying Facilities (QFs) at costs determined by the appropriate state's public utility commission. QFs are small

energy power producers and co-generators. Certain QFs can qualify as renewable resources required by state law; however, none of NPC's current QFs qualify.

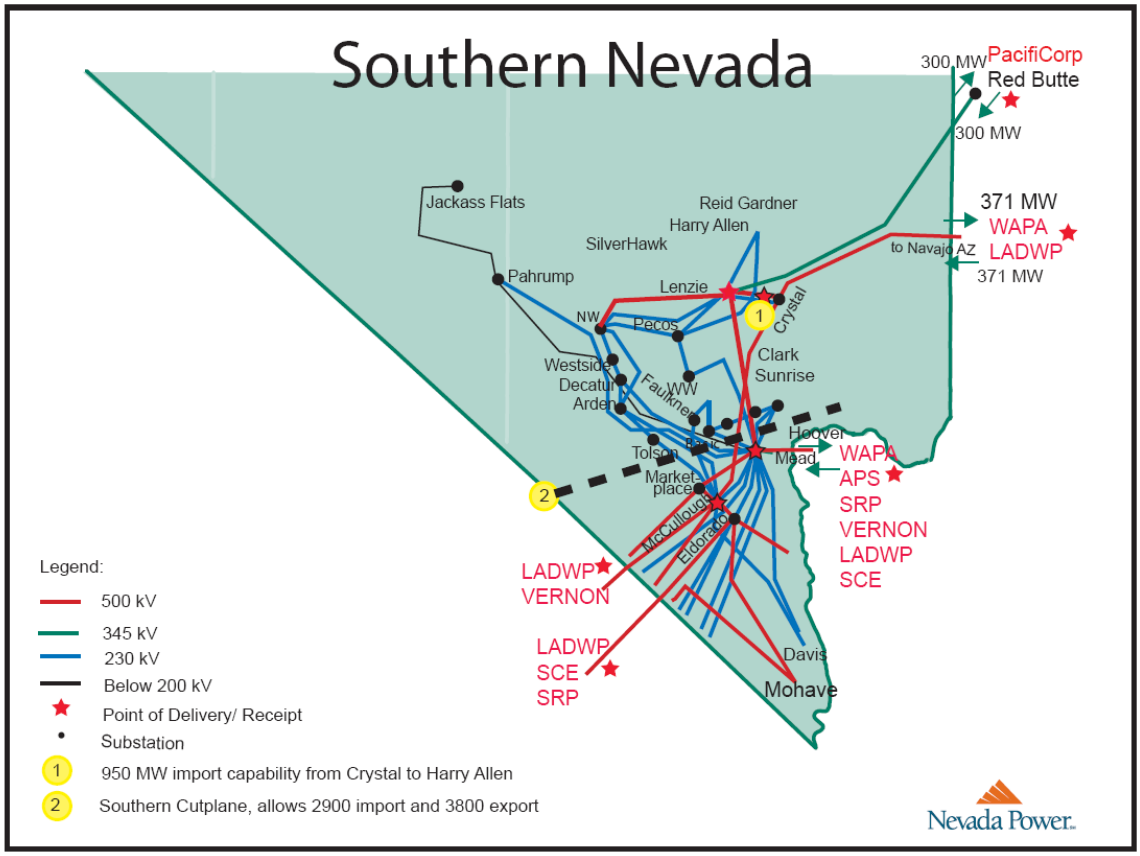
As of December 31, 2007, NPC had a total of 394 MW of contractual firm and non-firm capacity under contract with QFs. In 2007, energy purchased by NPC from the QFs constituted 28.6% of NPC's net purchased power requirements for native load and 10.6% of NPC's net system requirements (including generation).

**Transmission**

Electric transmission systems deliver energy from electric generators to distribution systems for final delivery to customers. Transmission systems are designed to move electricity over long distances because generators can be located anywhere from a few miles to hundreds of miles from customers.

NPC's electric transmission system is part of the Western Interconnection, the regional grid in the west. The Western Interconnection includes the interconnected transmission systems of fourteen western states, two Canadian provinces and the parts of Mexico that make up the Western Electricity Coordinating Council (WECC). WECC is one of ten regional councils of the North American Electric Reliability Corporation (NERC), the entity responsible for the reliability, adequacy and security of North America's bulk electric system.

NPC's transmission system links generating units within and outside of the NPC Balancing Authority Area to the NPC distribution system. NPC's transmission system is directly interconnected with the transmission systems of Western Area Power Administration, Arizona Public Service Company, Salt River Project, City of Vernon Municipal Light Department, Los Angeles Department of Water and Power, Southern California Edison, and PacifiCorp. NPC currently is not directly interconnected with SPPC; however, the Ely Energy Center Project includes a 500 kV line that will interconnect the transmission systems of the two companies. The map below shows NPC's transmission system:




Under the NERC guidelines, NPC is a Balancing Authority, a Transmission Operator, and a Transmission Owner. As defined by NERC, the Balancing Authority integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time (i.e., the Balancing Authority is responsible for assuring that the demands on the system are matched by an equivalent amount of resources, whether from generators within its area or from imports). The Transmission Operator is responsible for the reliability of its local transmission system, and operates or directs the operations of the transmission facilities. The Transmission Owner owns and maintains transmission facilities. NPC also

schedules power deliveries over its transmission system and maintains reliability through its operations and maintenance practices and by verifying that customers are matching loads with resources.

NPC plans, builds and operates a transmission system that delivered 23,030,806 MWh of electricity to customers in its Balancing Authority Area in 2007. The NPC system handled a peak load of 5,866 MW in 2007 through 1,694 line miles of transmission lines and other transmission facilities ranging from 60kV to 500kV. NPC processes generation and transmission interconnection requests and requests for transmission service from a variety of customers. These requests usually involve new planning studies and the negotiation of contracts with new and existing customers in this growing system. In the last 10 years, due primarily to high customer growth, NPC has constructed major transmission projects totaling 210 miles of high voltage transmission, with Centennial being the most recently completed project (100 miles).

*Transmission Regulatory Environment*

NPC's wholesale and retail access transmission services are regulated by the FERC under cost based regulation subject to the SPR Operating Companies Open Access Transmission Tariff (OATT). Transmission for NPC's bundled retail customers is subject to the jurisdiction of the PUCN for rate making purposes. In accordance with the OATT, NPC offers several transmission services to wholesale customers:

- Long-term and short-term firm point-to-point transmission service ("guaranteed" service with fixed delivery and receipt points),
- Non-firm point-to-point service ("as available" service with fixed delivery and receipt points), and
- Network transmission service (equivalent to the service NPC provides for NPC's bundled retail customers).

These services are all offered on a nondiscriminatory basis in that all potential customers, including NPC, have an equal opportunity to access the transmission system. NPC's transmission business is managed and operated independently from the energy marketing business in accordance with FERC Standards of Conduct.

On February 16, 2007, the Federal Energy Regulatory Commission issued a Final Rule, Order No. 890 Preventing Undue Discrimination and Preference in Transmission ("Order No. 890") and subsequently issued Order No. 890-A which essentially re-affirmed Order No. 890. The purpose of Order No. 890 is to strengthen the Open Access Transmission Tariff (OATT) to ensure that it achieves its original purpose of remedying undue discrimination, to provide greater specificity to reduce opportunities for undue discrimination and to increase transparency in the rules applicable to planning and the use of the transmission system. NPC has developed business practices and amended its OATT and is in compliance with Order 890. A compliance filing will be made by NPC as required by Order No. 890-A which is effective March 17, 2008.

NPC also made a filing with FERC on May 16, 2007, requesting modification of certain aspects of the OATT to ensure reservation of sufficient firm transmission import rights on their systems to comply with NPC's IRP, which call for the use of short-term power purchases to meet summer and winter peak demands. NPC's proposed OATT revisions was accepted for filing by FERC and permitted to become effective on July 13, 2007, for a term of three years.

On June 18, 2007, NERC issued 83 Mandatory Reliability Standards, 31 of which became enforceable under the authority of the FERC. The authority of the FERC includes the imposition of significant monetary sanctions for non-compliance, up to $1 million dollars per day per occurrence for violations. Prior to this action, these standards were in place and they were considered as voluntary upon the electric industry; however compliance was nevertheless expected. As such, NPC has been following the requirements in these standards since their inception.

NPC established a NERC Mandatory Reliability Standards Compliance Program in 2007. Additionally, in accordance with the compliance enforcement processes of NERC and WECC, NPC recently conducted a formal self-certification on the 31 NERC Standards that apply to NPC in its role as a Balancing Authority and Transmission Owner and Operator.

NPC is a member of WestConnect and the WestConnect Subregional Transmission Planning Committee. WestConnect is a group of southwest transmission-providing utilities that have agreed to work collaboratively to assess stakeholder and market needs and to investigate, analyze and recommend to its Steering Committee implementation of cost-effective enhancements to the western wholesale electricity market. In 2007 the WestConnect members worked collaboratively to develop consistent responses to FERC Order 890 requirements and developed regional business practices. The Subregional Transmission Planning Committee was established to provide coordinated transmission planning across the WestConnect footprint, including the Southwest Area Transmission Group that NPC participates in and a New Sierra Nevada Planning Group that SPPC will participate in.

**Construction Program**

NPC's construction program and estimated expenditures are subject to continuing review, and are periodically revised to include the rate of load growth, construction costs, availability of fuel types, the number and status of proposed independent

generation projects, the need for additional transmission capacity in southern Nevada, adequacy of rate relief, NPC's ability to raise necessary capital, and changes in environmental regulations. Under NPC's franchise agreements, it is obligated to provide a safe and reliable source of energy to its customers. Capital construction expenditures and estimates are reflective of NPC's obligation to serve its growing customer base.

Gross construction expenditures for 2007, including allowance for funds used during construction (AFUDC), net salvage, and contributions in aid of construction, were $766 million, and for the period 2003 through 2007, were $2.7 billion. Estimated construction expenditures for 2008 and the period from 2009 to 2012 are as follows (dollars in thousands):

| | 2008 | 2009-2012 | Total |
|---|---|---|---|
| Electric Facilities: | | | |
| Generation | $ 441,604 | $ 3,208,085 | $ 3,649,689 |
| Distribution | 240,830 | 908,169 | 1,148,999 |
| Transmission | 184,957 | 1,310,035 | 1,494,992 |
| Other | 137,875 | 170,555 | 308,430 |
| Total | $ 1,005,266 | $ 5,596,844 | $ 6,602,110 |

Total estimated cash requirements related to construction projects for 2008 and the 2009 to 2012 period consist of the following (dollars in thousands):

| | 2008 | 2009-2012 | Total |
|---|---|---|---|
| Construction Expenditures | $ 1,005,266 | $ 5,596,844 | $ 6,602,110 |
| AFUDC | (29,266) | (516,639) | (545,905) |
| Net Salvage/ Cost of Removal | (3,300) | (13,860) | (17,160) |
| Net Customer Advances and CIAC | (22,900) | (95,400) | (118,300) |
| Total Cash Requirements | $ 949,800 | $ 4,970,945 | $ 5,920,745 |

Major projects included in the 5 year estimated construction expenditures are as follows (dollars in thousands):

| Project | MW | Approved by PUCN | 2008 | 2009-2012 | Total | Cumulative expenditures as of December 31, 2007 | Projected in service/completion date |
|---|---|---|---|---|---|---|---|
| Clark Peaking Units | 619 | $ 384,348 | $ 131,308 | $ - | $ 131,308 | $ 272,129 | 2008 |
| Harry Allen Natural Gas Generation | 500 | - | 107,069 | 574,800 | 681,869 | 11,998 | 2011 |
| Ely Energy Center(1) | 1,500 | 240,000 | 27,616 | 1,918,443 | 1,946,059 | 40,429 | (3) |
| Renewable Projects(2) | 200 | - | 48,500 | 408,500 | 457,000 | 2,925 | 2010-2011 |
| EVAMP ( East Valley Area Master Plan) | | 228,300 | 11,742 | 200,759 | 212,501 | 1,159 | (3) |
| VARS ( Valley Area Routing & Siting) | | 230,057 | 16,228 | 210,360 | 226,588 | 19,748 | 2012 |
| Reid Gardner Environmental Compliance | | 83,940 | 61,461 | 103,135 | 164,596 | 51,554 | 2012 |
| Clark Environmental Compliance | | 60,000 | 16,462 | 33,219 | 49,681 | 10,490 | 2010 |

(1) See discussion below regarding the approval of the Ely Energy Center by the PUCN. These costs assume 80% allocated to NPC. However, the project is expected to extend beyond 2012, and as such, the total project cost is not included here.
(2) MWs reflect NPC's expected ownership share of these projects.
(3) These projects are expected to be completed after 2012.

Late in 2007, NPC began construction of 619 MW (nominally rated) natural gas-fired combustion turbine peaking units at the Clark Station. NPC anticipates an in-service date of mid 2008.

Late in 2007, NPC announced its plan to build a 500 MW natural gas-fired combined cycle plant as an expansion to its Harry Allen Generating Station, approximately 35 miles north of Las Vegas. The facility, subject to approval by the PUCN, is expected to be operational by the summer of 2011.

In November 2006 the PUCN approved NPC's IRP, which among other items, includes the approval of Phase 1 construction of the Ely Energy Center. The PUCN approved spending up to $300 million for development activities associated with Ely Energy Center with a limitation of $155 million placed on expenditures until the Utilities have obtained appropriate air permits. For planning purposes, it is currently assumed that the capacity of the project, as well as the development and constructions costs, would be shared by NPC and SPPC on an 80% - 20% basis, respectively. The project is expected to extend beyond 2012, as such total estimated costs for the project are not included in the table above. Depending on the timing of construction, negotiation of certain contracts, the potential initiation of any litigation challenging the project, and the timing and terms of permitting, among other factors, actual costs,

scope, and timing of the completion of the project will likely differ materially from initial estimates. See further discussion of Ely Energy Center in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, *Executive Overview*.

NPC has various renewable energy projects, including wind, solar and geothermal, under development and negotiation. Currently, these projects have not been approved by the PUCN; however, NPC intends to file one or more amendments in 2008 for these projects.

VARS is a "Master Plan" for proposed NPC transmission system improvements in the northern Las Vegas valley. This area of Clark County, Nevada, includes the City of Las Vegas, the City of North Las Vegas and sections of unincorporated Clark County, Nevada.

EVAMP is a "Master Plan" for proposed NPC transmission system improvements in the eastern and southeastern Las Vegas valley. This area of Clark County, Nevada, includes the City of Henderson and sections of unincorporated Clark County, Nevada.

Reid Gardner major capital and environmental projects include approximately $84 million of items previously approved by the PUCN and agreed upon with the EPA in April 2007, approximately $32 million for certain environmental projects as agreed upon with the NDEP as further discussed in Item 3. Legal Proceedings, Environmental, and other capital projects for which NPC has not received PUCN approval and is currently in the process of determining the feasibility of implementation.

Clark major capital and environmental projects includes the installation of capital equipment as agreed upon in the consent decree between NPC and the EPA in August 2007, as further discussed in Item 3. Legal Proceedings, Environmental.

## SIERRA PACIFIC POWER COMPANY

A Nevada corporation since 1965, SPPC was originally incorporated in Maine in 1912. SPPC became a subsidiary of SPR in 1984. Its mailing address is P. O. Box 10100 (6100 Neil Road), Reno, Nevada 89520-0024.

SPPC has two regulated business segments, SPPC electric and SPPC natural gas service, which are discussed separately in this section. SPPC has three primary, wholly-owned subsidiaries: GPSF-B, Piñon Pine Corp. (PPC) and Piñon Pine Investment Co. (PPIC). GPSF-B, PPC and PPIC, collectively, own Piñon Pine Company, LLC, which was formed to utilize federal income tax credits available under Section 20 of the Internal Revenue Code associated with the alternative fuel (syngas) produced by the coal gasifier located at the Piñon Pine Facility.

### SPPC Electric

### Business and Competitive Environment

*Overview*

SPPC is a public utility that generates, transmits and distributes electric energy to approximately 366,000 customers. The service territory covers over 50,000 square miles of 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.

*Electric Operations*

SPPC is charged with meeting the growing energy needs of the residential population and expanding business and public sectors. In addition to customer growth, demand and resulting revenues are impacted by rate changes, seasonal or atypical weather and customer use. SPPC's peak demand occurs in the summer with a slightly lower peak demand in the winter. Therefore, SPPC's revenues and associated expenses are not incurred or generated evenly throughout the year.

To serve its customer base, SPPC purchases power and generates electricity in accordance with an Energy Supply Plan, approved by the PUCN, as discussed in more detail later in this section and in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations. In a continued effort to reduce reliance on purchased power, SPPC is constructing a 541 MW gas-fired combined-cycle plant at Tracy, east of Reno. The plant is scheduled to be completed by the summer of 2008.

Electric loads and resulting revenues are affected by customer growth, weather, rate changes, and customer usage patterns. SPPC's revenues and associated expenses are not incurred or generated evenly throughout the year.

Nevada regulations require SPPC to file GRCs every three years with the PUCN to adjust rates including cost of service and return on investment. Nevada state regulations also require SPPC to file annual deferred energy accounting adjustment applications to either recover or refund balances that have been deferred and that represent the difference between fuel and purchased power costs actually incurred and the amounts collected in current retail rates. Additionally, SPPC is required quarterly to file rate cases to reset

BTER reflecting more current fuel and purchased power costs. Rate cases are discussed in more detail in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Regulatory Proceedings, and Note 3, Regulatory Actions, of the Notes to Financial Statements.

The FERC has jurisdiction under the Federal Power Act with respect to wholesale rates, service, interconnection, accounting, and other matters in connection with SPPC's sale of electricity for resale and interstate transmission. The FERC also has jurisdiction over the natural gas pipeline companies from which SPPC takes natural gas for fuel.

*Competition*

Nevada state law allows commercial customers with an average annual load of 1 MW or more to file a letter of intent and application with the PUCN to acquire electric energy, capacity, and ancillary services from another provider. The law requires customers wishing to choose a new supplier to receive the approval of the PUCN and meet certain public interest standards. In particular, departing customers must secure new energy resources that are not under contract to SPPC, the departure must not burden SPPC with increased costs or cause any remaining customers to pay increased costs, and the departing customers must pay their portion of any deferred energy balances. The PUCN adopted regulations prescribing the criteria that will be used to determine if there will be negative impacts to remaining customers or to SPPC. Customers wishing to choose a new supplier must provide 180-day notice to SPPC. SPPC would continue to provide transmission, distribution, metering, and billing services to such customers. Management believes that those customers securing energy from new energy suppliers will reduce SPPC's need to purchase power from potentially volatile wholesale energy markets.

Newmont Mining Corporation (Newmont) is constructing a new 203 MW generating plant in northeastern Nevada which is anticipated to be operational in 2008. In 2007, SPPC and Newmont entered into a wholesale power sale agreement and a new form of retail service, General Service New Generation (GS-4NG). Newmont will sell the electrical output from its plant to SPPC for at least 15 years under the long-term wholesale, purchased power agreement, and remain a retail customer of SPPC during at least that period under the terms of a retail service agreement and pursuant to a new rate schedule.

Currently, there are no other material applications pending with the PUCN to exit the system in SPPC's service territory.

**Sales**

In 2007, SPPC's electric operations contributed approximately $1.0 billion, or 83%, of SPPC's total revenues. Summer retail peak loads are primarily driven by air conditioning demand and irrigation pumping. Winter retail electric peak loads are primarily driven by increased demand for space heating, air movement (with forced air gas and oil furnaces), and ski resorts (hotels, lifts, etc.). SPPC's peak load increased at an average annual growth rate of 1.9% over the past five years, reaching 1,743 MW in July 2007.

SPPC's electric customers by class contributed the following toward 2007, 2006 and 2005 MWh sales:

| | MWh Sales (Billed and Unbilled) | | | | | |
|---|---|---|---|---|---|---|
| | 2007 | | 2006 | | 2005 | |
| | MWh | % of Total | MWh | % of Total | MWh | % of Total |
| Retail: | | | | | | |
| Residential | 2,519,666 | 28.6% | 2,480,681 | 28.2% | 2,381,389 | 25.5% |
| Mining | 1,742,641 | 19.8% | 1,873,177 | 21.3% | 2,716,309 | 29.1% |
| Commercial and Industrial | 4,512,825 | 51.2% | 4,356,878 | 49.5% | 4,136,208 | 44.3% |
| Total Retail | 8,775,132 | 99.6% | 8,710,736 | 99.0% | 9,233,906 | 98.9% |
| Wholesale | 14,581 | 0.2% | 69,757 | 0.8% | 81,856 | 0.9% |
| Streetlights | 15,943 | 0.2% | 15,502 | 0.2% | 15,105 | 0.2% |
| TOTAL | 8,805,656 | 100.0% | 8,795,995 | 100.0% | 9,330,867 | 100.0% |

In December 2005, Barrick Gold (Barrick), a large SPPC mining customer completed construction of a 118 MW generating facility to meet the majority of its electric power needs. Barrick continues to purchase transmission and distribution services from SPPC and is selling approximately 8 MW of capacity from its new generating facility to SPPC. Barrick MWh retail sales for 2005 were approximately 10.1% of total system sales for SPPC.

In 2006, mining MWh sales decreased significantly due to the departure of Barrick. In 2007, there were several special circumstances which contributed to the decrease in the mining MWh sales at SPPC including process changes by mining customers resulting in MWh savings and changes in ownership that resulted in one customer migrating to distribution only service. However, Nevada's precious metals mining industry continued to grow in 2007 as the rising price of gold on world markets led the state's mine

operators to increase production capacity and reported reserves. Exploration activities, which are considered to be critical to the future health of the industry in Nevada, continued at record levels with 2007 representing the sixth straight year when reported expenditures increased over the previous year.

SPPC has long-term electric service agreements with five of its major mining customers, with revenues under these agreements totaling approximately $88.1 million in 2007, which represented 8.5% of SPPC's electric operating revenues of $1.0 billion. These agreements include requirements for customers to maintain minimum demand and load factor levels. In addition, they include provisions to recover all investments for customer-specific facilities that have been made by SPPC on their behalf.

Large Commercial & Industrial customers including casinos, hospitals and small manufacturing companies and small Commercial & Industrial customers including restaurants, retail and small commercial businesses experienced growth in sales and customers from 2006 to 2007. Washoe County population growth from 2006-2007 was forecasted to be 2.4% per the State Demographer in July 2006. The population is expected to continue to grow at this approximate rate for the next 5 years.

**Demand**

***Load and Resources Forecast***

SPPC's integrated peak electric demand increased from 1,701 MW in 2006 to 1,743 MW in 2007. Variations in energy usage occur as a result of varying weather conditions, economic conditions and other energy usage behaviors, such as conservation efforts. This necessitates a continual balancing of loads and resources, and requires both purchases and sales of energy under short and long term contracts and the prudent management and optimization of available resources.

SPPC plans to meet its customers' needs through a combination of company-owned generation and purchased power. Remaining needs will be met through power purchased through RFPs or short term purchases.

Below is a table summarizing the forecasted summer electric capacity requirement and resource needs of SPPC (assuming no curtailment of supply or load, and normal weather conditions):

| | Forecasted Electric Capacity Requirements and Resources (MW) | | | | |
|---|---|---|---|---|---|
| | **2008** | **2009** | **2010** | **2011** | **2012[3]** |
| Total Requirements [1] | 1,963 | 2,017 | 2,040 | 2,064 | 2,078 |
| Resources: | | | | | |
| Company-owned existing generation | 1,010 | 1,022 | 1,022 | 1,022 | 1,012 |
| Company-owned new generation [2] | 541 | 541 | 541 | 541 | 541 |
| Contracts for power purchases | 447 | 364 | 450 | 488 | 361 |
| Total Resources | 1,998 | 1,927 | 2,013 | 2,051 | 1,914 |
| Total Additional Required [4] | - | 90 | 27 | 13 | 164 |

(1) Includes system peak load plus planning reserves.
(2) Includes Tracy combined cycle facility at 541 MW commencing in June 2008.
(3) Does not include the Ely Energy Center, as the Ely Energy Center is not expected to be operational prior to the end of 2012
(4) Total Additional Required represents the difference between the Total Requirements and Total Resources. Total Additional Required represents the amount needed to achieve the forecasted system peak plus a planning reserve margin.

**Energy Supply**

The energy supply function at SPPC encompasses the reliable and efficient operation of SPPC's owned generation, the procurement of all fuels and purchased power, and resource optimization.

SPPC faces energy supply challenges for its load control area. There is the potential for continued price volatility in SPPC'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. SPPC faces load obligation uncertainty due to the potential for customer switching. Some counterparties in these areas have significant credit difficulties, representing credit risk to SPPC.

In response to these energy supply challenges, SPPC has 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 a clear distinction between policy setting (or planning) and execution. Lastly, SPPC will continue to pursue a process of ongoing regulatory involvement and acknowledgement of the resource portfolio management plans. Details of the Energy Supply function are discussed in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Energy Supply.

***Total System***

SPPC manages a portfolio of energy supply options. The availability of alternate resources allows SPPC to dispatch its electric generation system in a more cost-effective manner under varying operating and fuel market conditions while maintaining system integrity. During 2007, SPPC generated 42.9% of its total electric energy requirements, purchasing the remaining 57.1% as shown below.

| | 2007 | | 2006 | | 2005 | |
|---|---|---|---|---|---|---|
| | MWh | % of Total | MWh | % of Total | MWh | % of Total |
| SPPC Company Generation | | | | | | |
| Gas/Oil | 2,282,636 | 24.3% | 2,167,898 | 23.2% | 2,345,196 | 23.9% |
| Coal | 1,705,789 | 18.1% | 1,848,591 | 19.8% | 2,000,719 | 20.4% |
| Hydro | 43,577 | 0.5% | - | 0.0% | 33,355 | 0.3% |
| Total Generated | 4,032,002 | 42.9% | 4,016,489 | 43.0% | 4,379,270 | 44.6% |
| Total Purchased | 5,376,364 | 57.1% | 5,334,341 | 57.0% | 5,441,047 | 55.4% |
| Total System | 9,408,366 | 100.0% | 9,350,830 | 100.0% | 9,820,317 | 100.0% |

As a supplement to its own generation, SPPC purchases spot, short-term firm, intermediate-term firm, long-term firm, and non-firm energy to meet its customer demand requirements. Total energy supply includes purchases from outside the electric system due to limited control area generation and also the need to access market energy supplies. SPPC's decision to purchase this energy is based on economics, mitigation of availability risk, and system import limits. Firm block purchases are transacted as both a price hedging strategy and to ensure that needed firm capacity is available over peak load periods. Spot market energy is purchased based on the economics of purchasing "as-available" energy when it is less expensive than SPPC's own generation, again, subject to net system import limits. SPPC's 2007 company generation increased 0.4% compared to 2006. SPPC's 2007 purchased power total MWhs increased 0.8% from SPPC's 2006 purchased power MWhs. See Energy Supply in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, for additional information.

***Risk Management***

See Item 7A, Quantitative and Qualitative Disclosures About Market Risk.

***Generation***

SPPC's generation capacity consists of a combination of 27 gas, oil and coal generating units with a combined summer capacity of 1,551 MWs as described in Item 2, Properties. In 2007, SPPC generated approximately 42.9% of its total system requirements.

In November 2006, the PUCN approved Phase 1 of the construction of the Ely Energy Center. The Ely Energy Center consists of two 750-megawatt coal fired generation units. The plan also includes further expansion possibilities involving two 500 MW coal gasification units when the technology becomes commercially viable. See discussion of Ely Energy Center earlier under SPR.

SPPC is constructing a new 541 MW (nominally rated) natural gas combined cycle facility at the existing Tracy Generating Station with a scheduled in-service date of mid 2008. The addition of this facility is expected to significantly reduce SPPC's reliance on purchased power compared to prior years.

### *Fuel Availability*

SPPC's 2007 fuel requirements for electric generation were provided by natural gas, coal, and oil. The average costs of gas, coal and oil for energy generation per MMBtu for the years 2003-2007, along with the percentage contribution to SPPC's total fuel requirements, were as follows:

| | Average Consumption Cost & Percentage Contribution to Total Fuel | | | | | |
|---|---|---|---|---|---|---|
| | Gas | | Coal | | Oil | |
| | $/MMBtu | Percent | $/MMBtu | Percent | $/MMBtu | Percent |
| 2007 | 8.34 | 57.8% | 1.93 | 42.0.% | 12.10 | 0.2% |
| 2006 | 8.92 | 55.9% | 1.83 | 43.9% | 10.15 | 0.3% |
| 2005 | 7.87 | 56.8% | 1.67 | 43.1% | 7.37 | 0.1% |
| 2004 | 7.32 | 53.1% | 1.39 | 44.9% | 6.14 | 2.0% |
| 2003 | 6.68 | 59.1% | 1.60 | 40.8% | 6.92 | 0.1% |

For a discussion of the change in fuel costs, see Results of Operations in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations.

Natural gas supplies are procured one season ahead of use through a competitive bidding process. The physical gas prices are set at an appropriate industry index during the month of current delivery. All natural gas is delivered to SPPC through the use of firm gas transport contracts. Monthly and daily gas supply adjustments are made by gas trading personnel based on the current energy marketplace.

SPPC has long-term coal contracts with Black Butte Coal Company and Arch Coal Sales Company that provide for deliveries through December 31, 2009 and December 31, 2011 respectively. These contracts represent 100% of Valmy's projected coal requirements in 2008, and 95% for 2009, 67% for 2010, and 57% for 2011.

Union Pacific Railroad originates and delivers coal to the Valmy station. An extension to the transportation services contract is in place that expires March 31, 2008. Currently, SPPC is negotiating a new contract and does not expect any disruption to service.

As of December 31, 2007, Valmy's coal inventory level was 238,663 tons or approximately 83 days of consumption at 100% capacity.

SPPC meets its needs for residual oil and diesel for generation through purchases on the spot market. SPPC attempts to maintain an actual residual oil inventory target level of about 325,000 barrels, which is equal to a 14-day supply at full load operation. Diesel inventory levels are kept at about five days full load operation supply since the diesel supply can be procured at various petroleum product terminals in and around the Reno-Sparks area.

### *Purchased Power*

SPPC, under the guidelines set forth in the SPPC Energy Supply Plan, continues to manage a diverse portfolio of contracted and spot market supplies, as well as its own generation, with the objective of minimizing its net average system operating costs. During 2007, SPPC purchased 57.1% of its total energy requirement.

SPPC purchases hydroelectric and thermal generation spot market energy, by the hour and by monthly RFP's, based upon economics and system import limits. Firm energy is also purchased during peak load periods as required to supply load and maintain adequate operating reserve margins. As off-system energy costs increase, SPPC supplies a higher percentage of its native load utilizing its fossil fuel generation.

SPPC has entered into long term purchase power contracts (3 or more years) with the following counterparties (excluding QFs and Renewables):

| Energy Provider | Capacity | Expiration |
|---|---|---|
| Newmont[(1)] | 203 MW | 2023 |
| Pacificorp | 75 MW | 2009 |
| Barrick | 8 MW | 2008 |

(1) Newmont anticipates completion of construction in 2008.

SPPC's credit standing affects the terms under which SPPC is able to purchase fuel and electricity in the western energy markets. As a result of SPPC's improved credit quality during 2007, SPPC was no longer required to provide cash deposits to be held by counterparties for the purchase of fuel and electricity nor to make pre-payments to counterparties for fuel; and reduced the number of counterparties requiring modified payment terms from the previous year.

SPPC is a member of the Northwest Power Pool and Western Systems Power Pool. These pools have provided SPPC further access to reserves and spot market power, respectively, in the Pacific Northwest and Southwest. In turn, SPPC's generation facilities provide a backup source for other pool members who rely heavily on hydroelectric systems.

*Qualifying Facilities*

Federal regulations, including the Public Utility Regulatory Policies Act of 1978 (PURPA), which were passed to promote renewable and alternative energy resources, and the Energy Policy Act of 2005 set out the requirements for utilities to purchase the output produced by Qualifying Facilities (QFs) at costs determined by the appropriate state's public utility commission. QFs are small energy power producers and co-generators. Certain QFs can qualify as renewable resources required by state law.

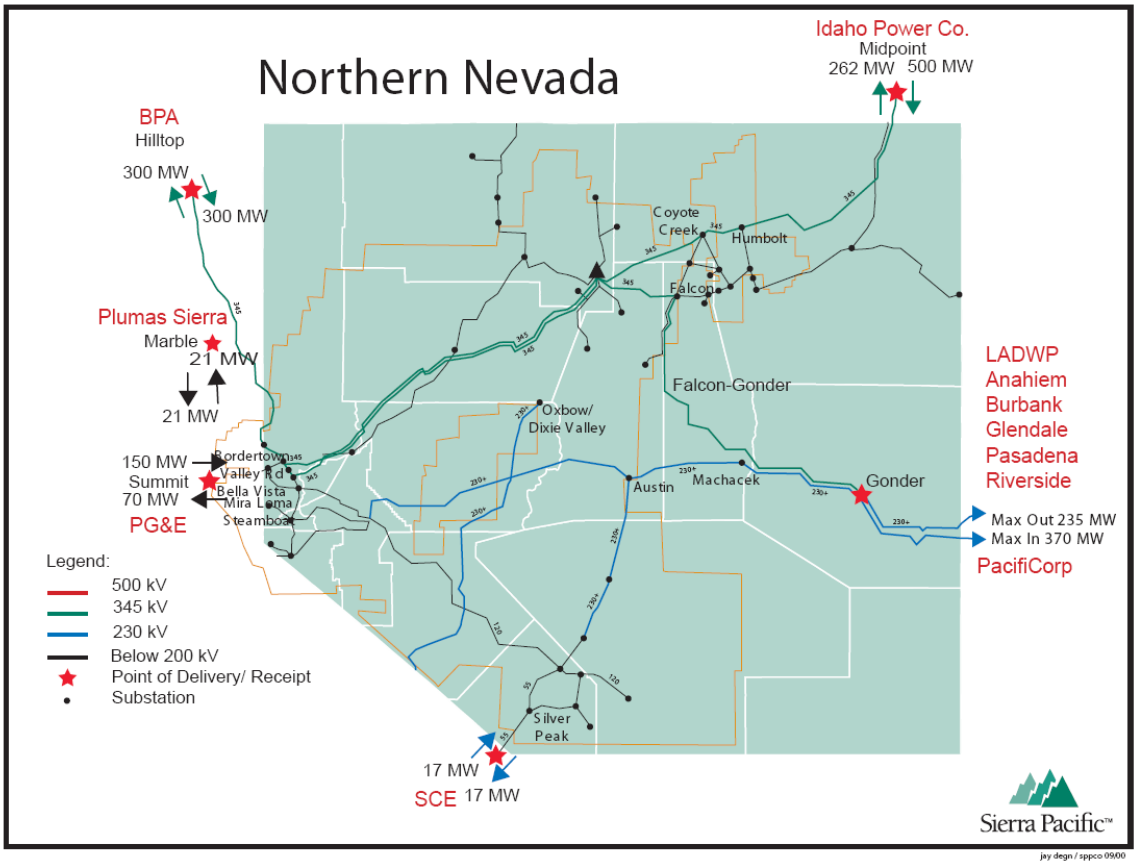
As of December 31, 2007, SPPC had a total of 194 MW of contractual firm and non-firm capacity under contract with QFs which qualify as renewable resources. In 2007, energy purchased by SPPC from the QFs constituted 17.5% of SPPC's net purchased power requirements for native load and 10.0% of SPPC's net system requirements (including generation).

**Transmission**

Electric transmission systems deliver energy from electric generators to distribution systems for final delivery to customers. Transmission systems are designed to move electricity over long distances because generators can be located anywhere from a few miles to hundreds of miles from customers.

SPPC's electric transmission system is part of the Western Interconnection, the regional grid in the west. The Western Interconnection includes the interconnected transmission systems of fourteen western states, two Canadian provinces and the parts of Mexico that make up the WECC. WECC is one of ten regional councils of the NERC, the entity responsible for the reliability, adequacy and security of North America's bulk electric system.

SPPC's transmission system links generating units within the SPPC Balancing Authority Area to the SPPC distribution system. SPPC's transmission system is directly interconnected with the transmission systems of Idaho Power; Los Angeles Department of Water and Power; the Municipal Utilities in the cities of Anaheim, Burbank, Glendale, Pasadena, and Riverside; Southern California Edison; PacifiCorp; Bonneville Power Administration; Pacific Gas & Electric and Plumas-Sierra Rural Electric Cooperative. SPPC currently is not directly interconnected with NPC; however, the Ely Energy Center Project includes a 500 kV line that will interconnect the transmission systems of the two companies. The map below shows SPPC's transmission system:




Under the NERC guidelines, SPPC is a Balancing Authority, a Transmission Operator, and a Transmission Owner. As defined by NERC, the Balancing Authority integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time (i.e., the Balancing Authority is responsible for assuring that the demands on the system are matched by an equivalent amount of resources, whether from generators within its area or from imports). The Transmission Operator is responsible for the reliability of its local transmission system, and operates or directs the operations of the transmission facilities. The Transmission Owner owns and maintains transmission facilities. SPPC schedules power deliveries over its transmission system and maintains reliability through its operations and maintenance practices and by verifying that customers are matching loads with resources.

SPPC plans, builds and operates a transmission system that delivered 9,408,366 MWh of electricity to customers in its Balancing Authority Area in 2007. The SPPC system handled a peak load of 1,743 MW in 2007 through 2,139 line miles of transmission lines and other facilities ranging from 60kV to 345kV. SPPC processes generation and transmission interconnection requests and requests for transmission service from a variety of customers. These requests usually involve new planning studies and the negotiation of contracts with new and existing customers in this growing system.

In the last 10 years, due primarily to high customer growth, SPPC has constructed major transmission projects totaling 452 miles of high voltage transmission. The projects completed include the Alturas Line (167 miles) and the Falcon – Gonder Line (180 miles) among others which increased SPPC's import capabilities.

*Transmission Regulatory Environment*

SPPC's wholesale and retail access transmission services are regulated by the FERC under cost based regulation subject to the SPR Operating Companies OATT Transmission for SPPC's bundled retail customers is subject to the jurisdiction of the PUCN for rate making purposes. In accordance with the OATT, SPPC offers several transmission services to wholesale customers:

- Long-term and short-term firm point-to-point transmission service ("guaranteed" service with fixed delivery and receipt points),
- Non-firm point-to-point service ("as available" service with fixed delivery and receipt points), and
- Network transmission service (equivalent to the service SPPC provides for SPPC's bundled retail customers).

These services are all offered on a nondiscriminatory basis in that all potential customers, including SPPC, have an equal opportunity to access the transmission system. SPPC's transmission business is managed and operated independently from the energy marketing business in accordance with FERC Standards of Conduct.

On February 16, 2007, the Federal Energy Regulatory Commission issued Order No. 890 and subsequently issued Order No. 890-A which essentially re-affirmed Order No. 890. The purpose of Order No. 890 is to strengthen the OATT to ensure that it achieves its original purpose of remedying undue discrimination, to provide greater specificity to reduce opportunities for undue discrimination and to increase transparency in the rules applicable to planning and the use of the transmission system. SPPC has developed business practices and amended its OATT and is in compliance with Order 890. A compliance filing will be made by SPPC as required by Order No. 890-A which is effective March 17, 2008.

SPPC also made a filing with FERC on May 16, 2007, requesting modification of certain aspects of the OATT to ensure reservation of sufficient firm transmission import rights on their systems to comply with SPPC's IRP, which call for the use of short-term power purchases to meet summer and winter peak demands. SPPC's proposed OATT revisions was accepted for filing by FERC and permitted to become effective on July 13, 2007, for a term of three years.

On June 18, 2007, NERC issued 83 Mandatory Reliability Standards 31 of which became enforceable under the authority of the FERC. The authority of the FERC includes the imposition of significant monetary sanctions for non-compliance, up to $1 million dollars per day per occurrence for violations. Prior to this action, these standards were in place and they were considered as voluntary upon the electric industry; however compliance was nevertheless expected. As such, SPPC has been following the requirements in these standards since their inception.

SPPC established a NERC Mandatory Reliability Standards Compliance Program in 2007. Additionally, in accordance with the compliance enforcement processes of NERC and WECC, SPPC recently conducted a formal self-certification on the 31 NERC Standards that apply to SPPC in its role as a Balancing Authority and Transmission Owner and Operator.

SPPC is a member of WestConnect and the WestConnect Subregional Transmission Planning Committee. WestConnect is a group of southwest transmission-providing utilities that have agreed to work collaboratively to assess stakeholder and market needs and to investigate, analyze and recommend to its Steering Committee implementation of cost-effective enhancements to the western wholesale electricity market. In 2007 the WestConnect members worked collaboratively to develop consistent responses to FERC Order 890 requirements and developed regional business practices. The Subregional Transmission Planning Committee was established to provide coordinated transmission planning across the WestConnect footprint, including the Southwest Area Transmission Group that NPC participates in and New Sierra Nevada Planning Group that SPPC will participate in.

**SPPC Gas**

**Business and Competitive Environment**

*Overview*

SPPC provides natural gas service to approximately 149,000 customers in an area of about 600 square miles in Nevada's Reno/Sparks area. SPPC also procures natural gas for electric power generation at the Tracy and Fort Churchill plants east of Reno.

*Gas Operations*

SPPC is charged with meeting the growing energy needs of the residential population and expanding business and public sectors. In addition to customer growth and demand, resulting revenues are impacted by rate changes, seasonal or atypical weather and customer use. Gas demand and revenues are very seasonal for SPPC Gas. Average daily temperatures range from 72 to 33 degrees Fahrenheit and the average high temperature to low temperature range from 91 to 21 degrees Fahrenheit. This wide temperature swing causes gas volumes to vary substantially depending on the weather.

In recent years, natural gas prices have trended upward and fluctuated widely, depending on such factors as weather, supply, demand, and the cost of competing fuels. Natural gas supply and demand fundamentals indicate immediate continued volatility. Relatively low-priced sources of fuel continue to be depleted and new supply is expensive to bring on-line. Additionally, gas demand has steadily increased, particularly due to an increase in gas-fired electric generation on a national level. Much of SPPC's electric generation resources use natural gas as their only fuel source.

SPPC is well connected with several major gas producing regions and the gas transport system into Northern Nevada is robust. SPPC's gas distribution system receives gas supplies from two interstate natural gas pipelines: Paiute Pipeline Company and Tuscarora Gas Transmission. In addition, SPPC has contracted for natural gas storage services to supplement firm and spot market purchases.

Nevada state regulations require annual filings to reset base purchased gas rates and recover deferred balances that include purchased gas costs above or below amounts collected in current rates. The regulations also require a Gas Supply Report as well as a Gas Informational Report to be filed annually. Natural gas commodity costs are passed directly through to customers on a dollar for dollar basis. SPPC may also file GRCs to adjust gas division rates including cost of service and return on investment. Rate cases are

discussed in more detail in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, Regulatory Proceedings, and Note 3, Regulatory Actions, of the Notes to Financial Statements.

*Competition*

SPPC's natural gas local distribution company (LDC) business is subject to competition from other suppliers and other forms of energy available to its customers. Large gas customers using 12,000 therms per month with fuel switching capability are allowed to participate in the Incentive Natural Gas Rate (INGR) tariff. Once a service agreement has been executed, a customer can compare natural gas prices under this tariff to alternative energy sources and choose their source of fuel. Additionally, customers using greater than 1,000 therms per day have the ability to secure their own gas supplies. As of January 1, 2008, there were 15 large customers securing their own supplies. These customers have a combined firm distribution load of approximately 4,953 Decatherms (Dth) per day. Transportation customers continue to pay firm and interruptible distribution charges. These customers are responsible for procuring and paying for their own gas supply, which reduces SPPC's purchases, but does not have an impact on net income.

**Revenue**

SPPC's natural gas business accounted for $205.4 million in 2007 operating revenues or 16.5% of SPPC's total revenues from continuing operations.

**Demand**

Growth in all sectors is expected to continue, although at a slower pace, as a result of new real estate developments under construction and planned for the near future in SPPC's distribution service area. Projected peak demand, which will only occur when the calculated average of the high and low temperatures for a given day drops to negative 5 degrees Fahrenheit, is estimated to be 187,522 Dth for the winter of 2007/2008.

To secure gas supplies for power generation and the LDC, SPPC contracted for firm winter, summer, and annual gas supplies with over two dozen Canadian and domestic suppliers. In 2007 seasonal and monthly gas supply net purchases averaged approximately 114,500 Dth per day with the winter period contracts averaging approximately 138,500 Dth per day, and the summer period contracts averaging approximately 106,500 Dth per day.

SPPC's firm natural gas supply is supplemented with natural gas storage services and supplies from a Northwest Pipeline Co. facility located at Jackson Prairie in southern Washington. The Jackson Prairie facility can contribute up to a total of 12,687 Dth per day of peaking supplies. SPPC also has storage on the Paiute Pipeline system. This liquefied gas storage facility provides for an incremental supply of 23,000 Dth per day and is available at any time with two hours notice. Therefore, this storage project supports increases in short term gas supply needs due to unforeseen events such as extreme weather patterns and pipeline interruptions.

Following is a summary of SPPC's transportation and storage portfolio as of December 31, 2007:

| Firm Transportation Capacity | Dth per day firm | Term |
|---|---|---|
| Northwest | 68,696 | (Annual) |
| Paiute | 68,696 | (November through March) |
| Paiute | 61,044 | (April through October) |
| Paiute | 23,000 | (LNG tank to Reno/Sparks) |
| Nova | 130,217 | (Annual) |
| ANG | 128,932 | (Annual) |
| GTN | 140,169 | (November through April) |
| GTN | 79,899 | (May through October) |
| Tuscarora | 132,823 | (Annual) |
| **Storage Capacity** | | |
| Williams: | 281,242 | Inventory capability at Jackson Prairie |
| | 12,687 | Withdrawal capability per day from Jackson Prairie |
| Paiute: | 303,604 | Inventory capability at Paiute LNG |
| | 23,000 | LNG Storage |

Total LDC Dth supply requirements in 2007 and 2006 were 15.4 million Dth and 15.5 million Dth, respectively. Electric generating fuel requirements for 2007 and 2006 were 25.0 million Dth and 23.5 million Dth, respectively.

**Gas Distribution**

As of December 31, 2007, SPPC owned and operated 2,005 miles of three-inch equivalent natural gas distribution piping. SPPC constructed a combined total of 11,137 feet of new 12 inch and 18 inch steel gas main in 2007 to support system growth. In

addition, and as part of its on going main and service replacement program, SPPC replaced approximately 12,450 feet of gas main of various sizes and approximately 176 service pipes that lead from the gas main to the individual meters in 2007.

**SPPC Electric and Gas**

**Construction Program**

SPPC's construction program and estimated expenditures are subject to continuing review and are periodically revised to include the rate of load growth, escalation of construction costs, availability of fuel types, the number and status of proposed independent generation projects, the need for additional transmission capacity in northern Nevada, adequacy of rate relief, SPPC's ability to raise necessary capital, SPPC's other cash needs and changes in environmental regulation. Under SPPC's franchise agreements, it is obligated to provide a safe and reliable source of energy to its customers. Capital construction expenditures and estimates are reflective of SPPC's obligation to serve its growing customer base.

SPPC's gross construction expenditures for 2007, including AFUDC and contributions in aid of construction, were $431 million, and for the period 2003 through 2007, were $1.2 billion. Estimated construction expenditures for 2008 and the period 2009-2012 are as follows (dollars in thousands):

| | 2008 | 2009-2012 | Total |
|---|---|---|---|
| Electric Facilities: | | | |
| Generation | $ 101,173 | $ 517,669 | $ 618,842 |
| Distribution | 78,761 | 392,692 | 471,453 |
| Transmission | 57,728 | 387,556 | 445,284 |
| Other | 31,148 | 58,557 | 89,705 |
| Total | 268,810 | 1,356,474 | 1,625,284 |
| Gas Facilities: | | | |
| Distribution | 19,700 | 89,364 | 109,064 |
| Other | 80 | 368 | 448 |
| Total | 19,780 | 89,732 | 109,512 |
| Common Facilities | 14,499 | 151,490 | 165,989 |
| TOTAL | $ 303,089 | $ 1,597,696 | $ 1,900,785 |

Total estimated cash requirements related to construction projects for 2008 and the 2009-2012 periods consist of the following (dollars in thousands):

| | 2008 | 2009-2012 | Total |
|---|---|---|---|
| Construction Expenditures | $ 303,090 | $ 1,597,695 | $ 1,900,785 |
| AFUDC | (11,252) | (82,602) | (93,854) |
| Net Salvage/ Cost of Removal | (1,200) | (5,015) | (6,215) |
| Net Customer Advances and CIAC | (20,600) | (86,560) | (107,160) |
| Total Cash Requirements | $ 270,038 | $ 1,423,518 | $ 1,693,556 |

Major projects included in the 5 year estimated construction expenditures are as follows (dollars in thousands):

| Project | MW | Approved by PUCN | 2008 | 2009-2012 | Total Cost 2008-2012 | Cumulative expenditures as of December 31, 2007 | Projected in service/ completion date |
|---|---|---|---|---|---|---|---|
| Tracy Combined Cycle | 541 | $ 420,920 | $ 43,560 | $ - | $ 43,560 | $ 377,538 | 2008 |
| Ely Energy Center[1] | 1,500 | 60,000 | 6,904 | 479,611 | 486,515 | 10,107 | (2) |

(1) See discussion below regarding the approval of the Ely Energy Center by the PUCN. These costs assume 20% allocated to SPPC. However, the project is expected to extend beyond 2012, and as a result, total project costs are not included.
(2) This project is expected to be completed after 2012.

In December 2005, the PUCN approved the construction of a 541-megawatt, combined cycle natural gas power plant at Tracy Generating Station. SPPC anticipates an in service date mid 2008.

In November 2006, the PUCN approved NPC's IRP, which among other items, includes the approval of Phase 1 construction of the Ely Energy Center. The PUCN approved spending up to $300 million for development activities associated with Ely Energy Center with a limitation of $155 million placed on expenditures until the Utilities' have obtained appropriate air permits. For planning purposes, it is currently assumed that the capacity of the project, as well as the development and constructions costs, would be shared by NPC and SPPC on an 80% - 20% basis, respectively. The project is expected to extend beyond 2012, as such total estimated costs for the project are not included in the table above. Depending on the timing of construction, negotiation of certain contracts, the potential initiation of any litigation challenging the project, and the timing and terms of permitting, among other factors, actual costs, scope, and timing of the completion of the project will likely differ materially from initial estimates. See further discussion of Ely Energy Center in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, *Executive Overview*.

## OTHER SUBSIDIARIES OF SIERRA PACIFIC RESOURCES

### Sierra Pacific Communications

Sierra Pacific Communications (SPC) was formed as a Nevada corporation in 1999 to identify and develop business opportunities in telecommunications services and infrastructure. SPC entered 2004 with two distinct business areas. The first involved a fiber optic system extending between Salt Lake City, Utah and Sacramento, California (the Long Haul System) and the second was the Metro Area Network (MAN) business in Las Vegas and Reno, Nevada. In 2004, SPC disposed of their MAN assets. Currently, management is assessing various business opportunities in regards to the remaining Long Haul System. SPCOM does not contribute significantly to the results of operations of SPR.

### Lands of Sierra

Lands of Sierra (LOS) was organized in 1964 to develop and manage SPPC's non-utility property in Nevada and California. These properties previously included retail, industrial, office and residential sites, timberland, and other properties. In keeping with SPR's strategy to focus on its core energy business, LOS continues to sell its remaining properties, which are located in Nevada and are of minimal book value. LOS does not materially contribute to the results of operations of SPR.

For a discussion of other subsidiaries' results of operations, refer to Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations.

## ENVIRONMENTAL (SPR, NPC AND SPPC)

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 Department of Air Quality and Environmental Management (DAQEM) administer regulations involving air quality, water pollution, solid, and hazardous and toxic waste. See Note 13, Commitments and Contingencies, Environmental of the Notes to Financial Statements, for further discussion.

### Federal Legislative and Regulatory Initiatives

The topic of climate change continues to evolve, and response to this issue brings with it significant environmental, economic and social implications for SPR and other electric utilities. The United States currently has no policy or regulation to address greenhouse gas emissions; the main emphasis to date being reliance on voluntary measures. While several bills have been introduced in Congress that would address carbon dioxide emissions, none have been enacted to-date. Environmental advocacy groups and regulatory agencies in the United States are also focusing considerable attention on carbon dioxide emissions from power generating facilities and their potential role in climate change.

Every generation alternative – whether fossil fuels, nuclear, or renewable power options– has environmental and financial impacts. SPR recognizes these impacts and closely links its business objective of generating reliable, cost-effective energy with its environmental responsibilities. SPR has and will continue to identify projects that minimize or offset greenhouse gas emissions and believes precautionary actions to limit greenhouse gas emissions are appropriate. In 2006, SPR joined the California Climate Action Registry (the Registry) and voluntarily committed to commence an annual inventory, certify and publicly report on greenhouse gas emissions from NPC and SPPC through the Registry. At the close of 2007, SPR submitted its first year of verified emissions to the Registry.

SPR's environmental philosophy accentuates prudent use of natural resources and to that end, SPR supports multiple program areas aimed at achieving overall air emission reductions. Some examples are:

- Installation of commercially-proven pollution controls coupled with an emphasis on continued operational excellence to achieve further plant efficiency improvements. SPR's new natural gas-fired generating plants require the combustion of far less fuel than older facilities to produce each kWh of electrical output. As new generation is added to the system, SPR is concurrently evaluating and eliminating older, less efficient units from its fleet.
- Maintenance of robust demand-side management programs, including energy efficiency and conservation education and support. These programs increase the adoption of energy-efficient equipment by our customers, thereby creating savings on energy bills and potentially delaying the need for additional power plant, transmission, and distribution construction.
- Development of technology solutions through funding and participation in collaborative research programs for advanced coal technologies, as well as potential options for carbon sequestration. SPR is reserving space in its proposed Ely Energy Center design that will allow the retrofit of carbon capture technology once it becomes commercially viable.
- Expansion of company owned renewable energy sources and continued use of purchase power agreements and investments that focus on lower or non-emitting generation resources. The State of Nevada mandates that an increasing percentage of the energy SPR sells must come from renewable sources, reaching 20 percent by 2015. Two large-scale solar projects in the State commenced operations in 2007 which resulted in Nevada being number one in the nation for solar watts generated per person and the percentage of solar to total kWhs sold.

SPR and the Utilities may be affected by future federal or state legislation or regulations mandating a reduction in greenhouse gas emissions. Because of the high level of uncertainty regarding when any legislation or regulations will be adopted in this area or what form they will take, management is unable at this time to evaluate the potential economic impact of any such measures on SPR or the Utilities.

Congress has from time to time considered legislation that would amend the Clean Air Act to target specific emissions from electric utility generating plants. If enacted, this legislation would require reductions in emissions of nitrogen oxides, sulfur dioxide and mercury. There is significant uncertainty at this time as to whether such legislation will be passed by Congress and, if passed, the timing and extent of any required reductions.

Of particular importance to SPR, in 2005 the EPA issued its Clean Air Mercury Rule (CAMR) and Regional Haze Rule. SPR notes that both rules have been the subject of litigation by various parties.

*CAMR* — EPA's CAMR was based on a national cap-and-trade system which was designed to achieve a 70 percent reduction in mercury emissions. It affected all coal and oil-fired generating units across the country greater than 25 megawatts. Compliance with this rule was to have occurred in two phases, with the first phase beginning in 2010 and the second phase in 2018. Under this Federal program, states would have been allocated mercury allowances based on coal type and their baseline heat input relative to other states. Each electric generating unit would have been allocated mercury allowances based on its percentage of total coal heat input for the state. In late 2006, the State of Nevada proposed its own mercury emission reduction rule in keeping with EPA's proposed model program.

On February 8, 2008, in *State of New Jersey v. EPA*, the US Court of Appeals for the District of Columbia Circuit vacated two EPA rules issued under the Clean Air Act regarding the emission of hazardous air pollutants ("HAPs") from electric utility steam generating units ("EGUs"), including the CAMR as well as a rule delisting EGUs from HAPs requirements.

EPA has not yet indicated how it will respond to this action, including whether EPA may appeal or seek reconsideration of the decision. If the decision remains final, it appears that EPA will need to propose a new maximum achievable control technology ("MACT") standard for mercury emissions. However, if EPA does not act relatively quickly, sources may have to submit permit applications to establish "case by case" MACT for individual sources. While the final outcome and timing for EPA's actions cannot be estimated at this point, the Utilities will continue to monitor this issue and assess its potential impact on our generation fleet as new information becomes available.

*Regional Haze Rules* — In June 2005, the EPA finalized amendments to the July 1999 regional haze rules; thereby requiring states to develop implementation plans to demonstrate compliance. These amendments apply to the provisions of the regional haze rule that require emission controls for industrial facilities emitting air pollutants that reduce visibility by causing or contributing to regional haze. States are required to identify the facilities that will have to reduce emissions through installation of emission controls, known as best available retrofit technology (BART), and then set emissions limits for those facilities. The State of Nevada has begun its BART rule development with an expected rollout occurring in 2008, and SPR is actively involved in the stakeholder process. The impacted BART units are Reid Gardner 1, 2 & 3; Ft. Churchill 1 & 2; and Tracy Units 1, 2 & 3. Compliance options to meet BART can involve either retirement or the addition of emission reduction equipment on the affected units. Due to the uncertainties of final technology requirements and implementation timing, SPR is not able to estimate the cost impact to its facilities at this time.

## GENERAL – EMPLOYEES (ALL)

SPR and its subsidiaries had 3,270 employees as of January 24, 2008, of which 1,865 were employed by NPC and 1,293 were employed by SPPC.

NPC's current contract with the International Brotherhood of Electrical Workers (IBEW) Local No. 396, which covers approximately 60% of NPC's workforce, was renegotiated and ratified in April 2005 and was in effect until February 2008. However, current contract language allows for the extension of the contract while negotiations on a new labor contract continue. NPC and IBEW Local 396 opened general negotiations on November 5, 2007 for a contract subsequent to the 2005 through 2008 agreement. All terms of the current collective bargaining agreement will continue during the negotiating process and until a new contract is ratified by IBEW membership. If either party wishes to terminate the contract they must provide the other party one week's written notice.

SPPC's amendment to its existing contract with the IBEW Local No. 1245, which represents approximately 65% of SPPC's workforce, was ratified by the IBEW on February 28, 2007. The contract will be in effect through December 31, 2009. The three-year contract provided for an 8% general wage increase for most bargaining unit employees effective March 5, 2007, with 4% increases in 2008 and 2009. Due to protracted negotiations, bargaining unit employees did not receive a wage increase in 2006 but did receive a 4% increase in 2007 for retroactive pay. Some classifications will receive lump sum payments in lieu of a general wage increase and others will receive equity raises in addition to their general wage increase. Other significant negotiated items include modifications to holiday schedules, health care cost sharing, post retirement benefits, and other operational productivity improvements.

## GENERAL – FRANCHISES (NPC AND SPPC)

The Utilities have nonexclusive local franchises or revocable permits to carry on their business in the localities in which their respective operations are conducted in Nevada and California. The franchise and other governmental requirements of some of the cities and counties in which the Utilities operate provide for payments based on gross revenues. Public utilities are required by law to collect from their customers a universal energy charge (UEC) based on consumption. The UEC is designed to help those customers who need assistance in paying their utility bills or need help in paying for ways to reduce energy consumption. During 2007 the Utilities collected $124.2 million in franchise or other fees based on gross revenues. They collected $10.1 million in UEC based on consumption. They also paid and recorded as expense $1.0 million of fees based on net profits.

The Utilities will apply for renewal of franchises in a timely manner prior to their respective expiration dates.

## ITEM 1A RISK FACTORS

***If NPC and/or SPPC do not receive favorable rulings in their future GRCs, it will have a significant adverse effect on our financial condition, cash flows and future results of operations.***

The Utilities' revenues and earnings are subject to change as a result of regulatory proceedings known as GRCs, which the Utilities file with the PUCN approximately every three years. In the Utilities' GRCs, the PUCN establishes, among other things, their recoverable rate base, their return on common equity, overall rate of return, depreciation rates and their cost of capital.

For a discussion of NPC's and SPPC's recent GRCs, see "Management's Discussion and Analysis of Financial Condition and Results of Operations – Regulatory Proceedings (Utilities)".

We cannot predict what the PUCN will direct in their orders on the Utilities' pending or future GRCs. Inadequate base energy rates would have a significant adverse effect on the Utilities' financial condition and future results of operations and could cause downgrades of their securities by the rating agencies and make it significantly more difficult or expensive to finance operations and construction projects and to buy fuel, natural gas and purchased power from third parties.

***The Utilities plan to make significant capital expenditures to construct new generation and transmission facilities. If we are unable to finance such construction or limit the amount of capital expenditures associated with those facilities to forecasted levels, our financial condition and results of operation could be adversely affected.***

Our long term business objectives include plans to construct new generation and transmission facilities. Such construction will require significant capital expenditures that the Utilities may finance through significant additional borrowings under the Utilities' respective credit facilities, through additional debt financings in private or public offerings or through debt or equity financings by SPR. We cannot be sure that we will be able to obtain financing for such capital expenditures on favorable terms, or at all. Neither can we be sure that we will be successful in limiting capital expenditures to planned amounts, particularly in the event of escalating costs for materials, labor and environmental compliance, including the escalating costs for materials, labor and environmental compliance in connection with the construction of coal generation facilities as a result of timing delays and other economic factors. If we cannot obtain favorable financing arrangements for our planned capital expenditures, limit such capital expenditures to forecasted amounts and/or recover amounts spent on construction through future filings with the PUCN, our financial condition and results of operation would be adversely affected.

***If Federal and/or State requirements are imposed on NPC and SPPC mandating further emission reductions, including limitations on carbon dioxide (CO2) emissions, such requirements could make some electric generating units, including the proposed Ely Energy Center, uneconomical to construct, maintain or operate.***

Emissions of nitrogen and sulfur oxides, mercury and particulates from fossil fueled generating plants are potentially subject to increased regulations, controls and mitigation expenses. Certain Congressional leaders, environmental advocacy groups and regulatory agencies in the United States have also been focusing considerable attention on carbon dioxide (CO2) emissions from power generation facilities and their potential role in climate change. Particular attention has been focused on proposals for new coal-fired generation facilities, such as the Ely Energy Center, and a number of such proposed facilities have been delayed or cancelled. Moreover, there are many legislative and rulemaking initiatives pending at the federal and state level that are aimed at the reduction of greenhouse gas emissions. We cannot predict the outcome of pending or future legislative and rulemaking proposals, their effect on the permitting requirements for the Ely Energy Center, or their effect otherwise on the project overall, including future PUCN review and approval. Future changes in environmental laws or regulations governing emissions reductions could make certain electric generating units, especially those utilizing coal for fuel, uneconomical to construct, maintain or operate or could require design changes or the adoption of new technologies that could significantly increase costs or delay in-service dates. In addition, any legal obligation that would require the Utilities to substantially reduce their emissions beyond present levels could require extensive mitigation efforts and, in the case of CO2 legislation, would raise uncertainty about the future viability of fossil fuels, particularly coal, as an energy source for new and existing electric generation facilities.

If the Ely Energy Center is delayed or if the current planning assumptions for the project change materially, the Utilities would need to explore alternative sources of power for meeting the projected electricity demand in their service territories. The most likely alternative to coal generation would involve increased use of natural gas, either through increased use of natural gas fueled purchased power or the construction of additional Utility-owned natural gas generating facilities, or a combination of both. Such increased use of natural gas likely would further subject the Utilities and their customers to natural gas price volatility, as well as to any potential regional supply adequacy issues.

***The Utilities are subject to numerous environmental laws and regulations that may increase our cost of operations, impact or limit our business plans, or expose us to environmental liabilities.***

The Utilities are subject to extensive federal, state and local laws and regulations relating to environmental protection. These laws and regulations can result in increased capital, construction, operating, and other costs. These laws and regulations generally require us to obtain and comply with a wide variety of environmental licenses, permits, inspections and other approvals, and may be enforced by both public officials and private individuals. We cannot predict the outcome or effect of any action or litigation that may arise from applicable environmental regulations.

In addition, either of the Utilities may be required to be a responsible party for environmental clean up at sites identified by environmental agencies or regulatory bodies. We cannot predict with certainty the amount or timing of future expenditures related to environmental matters because of the difficulty of estimating clean up costs. There is also uncertainty in quantifying liabilities under environmental laws that impose joint and several liability on all potentially responsible parties. Environmental regulations may also require us to install pollution control equipment at, or perform environmental remediation on, our facilities.

Existing environmental regulations regarding air emissions (such as NOx, SO2 or mercury emissions), water quality and other toxic pollutants may be revised or new climate change laws or regulations may be adopted or become applicable to us. Revised or additional laws or regulations, which result in increased compliance costs, increased construction costs or additional operating restrictions, could have a material adverse effect on our financial condition and results of operations particularly if those costs are not fully recoverable from our customers and/or if such regulations make currently contemplated construction projects technologically obsolete or economically non-viable.

Furthermore, we may not be able to obtain or maintain all environmental regulatory approvals necessary to our business. If there is a delay in obtaining any required environmental regulatory approval or if we fail to obtain, maintain or comply with any such approval, operations at our affected facilities could be delayed, halted or subjected to additional costs.

***The Utilities are subject to fuel and wholesale electricity pricing risks, which could result in unanticipated liabilities and cash flow requirements or increased volatility in our earnings, and to related credit and liquidity risks.***

The Utilities' business and operations are subject to changes in purchased power prices and fuel costs that may cause increases in the amounts they must pay for power supplies on the wholesale market and the cost of producing power in their generation plants. As evidenced by the western utility crisis that began in 2000, prices for electricity, fuel and natural gas may fluctuate substantially over relatively short periods of time and expose the Utilities to significant commodity price risks. Among the factors that could affect market prices for electricity and fuel are:

- prevailing market prices for coal, oil, natural gas and other fuels used in generation plants, including associated transportation costs, and supplies of such commodities;
- further concentration of gas as a source if the Utilities cannot diversify into coal;
- changes in the regulatory framework for the commodities markets that they rely on for purchased power and fuel;

- liquidity in the general wholesale electricity market;
- the actions of external parties, such as the FERC or independent system operators, that may impose price limitations and other mechanisms to address volatility in the western energy markets;
- weather conditions impacting demand for electricity or availability of hydroelectric power or fuel supplies;
- union and labor relations;
- natural disasters, wars, acts of terrorism, embargoes and other catastrophic events; and
- changes in federal and state energy and environmental laws and regulations.

As a part of the Utilities' risk management strategy, they focus on executing contracts for power deliveries to the Utilities' physical points of delivery to mitigate the commodity-related risks listed above. To the extent that open positions exist, fluctuating commodity prices could have a material adverse effect on their cash flows and their ability to operate and, consequently, on our financial condition.

Increasing energy commodity prices, particularly with respect to natural gas, have a significant effect on our short-term liquidity. Although the Utilities are entitled to recover their prudently incurred power, natural gas and fuel costs through deferred energy rate case filings with the PUCN, if current commodity prices increase, the Utilities' deferred energy balances will increase, which will negatively affect our cash flow and liquidity until such costs are recovered from customers.

The Utilities are also subject to credit risk for losses that they incur as a result of non-performance by counterparties of their contractual obligations to deliver fuel, purchased power, natural gas (for resale) or settlement payments. The Utilities often extend credit to counterparties and customers and they are exposed to the risk that they may not be able to collect amounts owed to them. Credit risk includes the risk that a counterparty may default due to circumstances relating directly to it, and also the risk that a counterparty may default due to circumstances that relate to other market participants that have a direct or indirect relationship with such counterparty. Should a counterparty, customer or supplier fail to perform, the Utilities may be required to replace existing contracts with contracts at then-current market prices or to honor the underlying commitment.

The Utilities are also subject to liquidity risk resulting from the exposure that their counterparties perceive with respect to the possible non-performance by the Utilities of their physical and financial obligations under their energy, fuel and natural gas contracts. These counterparties may under certain circumstances, pursuant to the Utilities agreements with them, seek assurances of performance from the Utilities in the form of letters of credit, prepayment or cash deposits. In periods of price volatility, the Utilities' exposure levels can change significantly, which could have a significant negative impact on our liquidity and earnings.

As of February 22, 2007, NPC had approximately $594.9 million available under its $600 million revolving credit facility and SPPC has approximately $330.5 million available under its $350 million revolving credit facility. The combined effects of higher natural gas prices, significant deferred energy balances and ongoing under-recovery of fuel, energy and natural gas costs may have a negative effect on our short-term liquidity.

***If NPC and/or SPPC do not receive favorable rulings in the deferred energy applications that they file with the PUCN and they are unable to recover their deferred purchased power, natural gas and fuel costs, they will experience an adverse impact on cash flow and earnings. Any significant disallowance of deferred energy charges in the future could materially adversely affect their cash flow, financial condition and liquidity.***

Under Nevada law, purchased power, natural gas and fuel costs in excess of those included in base rates are deferred as an asset on the Utilities' balance sheets and are not shown as an expense until recovered from their retail customers. The Utilities are required to file deferred energy accounting adjustment applications with the PUCN at least once every twelve months so that the PUCN may verify the prudence of the energy costs. Nevada law also requires the PUCN to act on these cases within a specified time period. Any of these costs determined by the PUCN to have been imprudently incurred cannot be recovered from the Utilities' customers. Past disallowances in the Utilities' deferred energy cases have been significant, especially the 2002 disallowance of $434 million in NPC's deferred energy rate case, which resulted in ratings downgrades of our debt securities and adversely affected our liquidity and access to capital markets.

For a discussion of NPC's and SPPC's recent and pending deferred energy rate cases, see "Management's Discussion and Analysis of Financial Condition and Results of Operations – Regulatory Proceedings (Utilities)".

Material disallowances of deferred energy costs, gas costs or inadequate base tariff energy rates would have a significant adverse effect on the Utilities' financial condition and future results of operations, could cause downgrades of SPR's and the Utilities' securities by the rating agencies and could make it more difficult or expensive to finance operations and construction projects and buy fuel, natural gas and purchased power from third parties.

Historically, the Utilities have purchased a significant portion of the power that they sell to their customers from power suppliers. If the Utilities' and/or their power suppliers' credit ratings are downgraded, the Utilities may experience difficulty entering into new power supply contracts, and to the extent that they must rely on the spot market, they may experience difficulty obtaining such power from suppliers in the spot market in light of their financial condition, or the financial condition of their power suppliers. In addition, if the Utilities experience unexpected failures or outages in their generation facilities, they may need to purchase a greater

portion of the power they provide to their customers. If they do not have sufficient funds or access to liquidity to obtain their power requirements, particularly for NPC at the onset of the summer months, and are unable to obtain power through other means, their business, operations and financial condition will be materially adversely affected.

***If SPR is precluded from receiving dividends from the Utilities, its financial condition, and its ability to meet its debt service obligations, pay dividends and make capital contributions to its subsidiaries, will be materially adversely affected.***

SPR is a holding company with no significant operations of its own. Its cash flows are substantially derived from dividends paid to it by the Utilities, which are typically utilized to service SPR's debt and reinvested in SPR's subsidiaries as contributions to capital. Subject to various factors to be considered periodically by SPR's Board of Directors, a portion of SPR's cash flow may be used to make dividend payments on its common stock.

The Utilities are subject to restrictions on their ability to pay dividends to SPR under the terms of certain of their respective financing agreements. In addition, certain provisions of the Federal Power Act could, depending on the interpretation thereof, limit or prohibit the payment of dividends to SPR.

Assuming that the Utilities meet the requirements to pay dividends under the Federal Power Act, under their material dividend restrictions, each of the Utilities may pay dividends to SPR if each such Utility can meet a 2 to 1 fixed charge coverage ratio test. If that condition is met, the amount of dividends that can be paid is an amount less than 50% of such Utility's consolidated net income plus the amount of capital contributions made to such Utility by SPR for the period from the date of issuance of the respective series of debt securities to the end of the most recently ended fiscal quarter. If they do not meet these conditions, the Utilities can still pay SPR's reasonable fees and expenses, provided that each such Utility has a cash flow to fixed charge coverage ratio of at least 1.75:1 over the prior four fiscal quarters. Due to the cumulative calculation of this restriction, NPC's Series G Notes and SPPC's Series H Notes are effectively the most restrictive dividend limitations. In addition, under the most restrictive of their dividend restrictions, each of the Utilities has a carve-out that permits them to pay up to $25 million to SPR from the date of issuance of the applicable debt securities, regardless of whether the other conditions to paying dividends have been met. Although each Utility currently meets the conditions described above, a significant loss by either Utility could cause that Utility to be precluded from paying dividends to SPR until such time as that Utility again meets the coverage test. In 2007, SPR received approximately $42.5 million in dividends from the Utilities to meet its debt service obligations.

***We cannot assure investors that future dividend payments on our Common Stock will be made or, if made, in what amounts they may be paid.***

On July 28, 2007, SPR's Board of Director's declared a quarterly cash dividend of $0.08 per share of Common Stock, payable on September 12, 2007 to shareholders of record on August 24, 2007. This dividend was the first declared by the Board since February 2002. On November 1, 2007, the Board declared a quarterly dividend on SPR's Common Stock of $0.08 per share. This dividend of approximately $17.7 million was paid on December 12, 2007 to shareholders of record on November 19, 2007. Additionally, on February 7, 2008, SPR's Board of Directors declared a quarterly cash dividend of $0.08 per share payable on March 12, 2008 to common shareholders of record on February 22, 2008. Dividends are considered periodically by SPR's Board of Directors and are subject to factors that ordinarily affect dividend policy, such as current and prospective financial condition, earnings and liquidity, prospective business conditions, regulatory factors, and dividend restrictions in SPR's and the Utilities' financing agreements. The Board will continue to review these factors on a periodic basis to determine if and when it would be prudent to declare a dividend on SPR's Common Stock. There is no guarantee that dividends will be paid in the future, or that, if paid, the dividends will be paid in the same amount or with the same frequency as in the past.

***SPR's indebtedness is effectively subordinated to the liabilities of its subsidiaries, particularly NPC and SPPC. SPR and the Utilities have the ability to issue a significant amount of additional indebtedness under the terms of their various financing agreements.***

Because SPR is a holding company, its indebtedness is effectively subordinated to the Utilities' existing indebtedness and other future liabilities, including claims by the Utilities' trade creditors, debt holders, secured creditors, taxing authorities, and guarantee holders. SPR conducts substantially all of its operations through its subsidiaries, and thus SPR's ability to meet its obligations under its indebtedness and to pay any dividends on its common stock will be dependent on the earnings and cash flows of those subsidiaries and the ability of those subsidiaries to pay dividends or to advance or repay funds to SPR. As of December 31, 2007, the Utilities had approximately $3.7 billion of debt outstanding. The terms of SPR's indebtedness restrict the amount of additional indebtedness that SPR and the Utilities may issue. Based on SPR's December 31, 2007 financial statements, assuming an interest rate of 7%, SPR's indebtedness restrictions would allow SPR and the Utilities to issue up to approximately $1.1 billion of additional indebtedness in the aggregate, unless the indebtedness being issued is specifically permitted under the terms of SPR's indebtedness. In addition, NPC and SPPC are subject to restrictions under the terms of their various financing agreements on their ability to issue additional indebtedness.

***Whether SPR can procure sufficient renewable energy to meet Nevada's increasing renewable energy Portfolio Standard.***

Nevada law sets forth the renewable energy portfolio standard (Portfolio Standard) requiring providers of electric service to acquire, generate, or save from renewable energy systems or energy efficiency measures a specific percentage of its total retail energy sales from renewable energy sources, including biomass, geothermal, solar, waterpower and wind projects. The Portfolio Standard requires the energy acquired from a renewable energy system be transmitted or distributed via a power line which is connected to a facility or system, owned, operated or controlled by the Utilities. Other restrictions are placed on energy acquired from energy efficiency measures which may not exceed more than 25 percent of the Portfolio Standard and half of those savings must come from residential customers.

In years 2007 and 2008, the Portfolio Standard requires that nine percent (9%) of total retail energy sales come from renewable energy. The Portfolio Standard increases by 3% every other year until it reaches 20% in 2015. Moreover, not less than 5% of the total Portfolio Standard must be met by solar resources.

Due to periodic increases in the Portfolio Standard and increasing retail sales, the Utilities must acquire increasing amounts of renewable energy. The Utilities' success in meeting the increasing Portfolio Standard remains largely dependent on their ability to acquire additional renewable energy from either self-owned renewable generation facilities or the purchase of renewable energy from third-party developers and a decrease in demand through qualified conservation and energy efficiency measures.

***The Utilities' ability to access the capital markets is dependent on their ability to obtain regulatory approval to do so.***

The Utilities will need to continue to support working capital and capital expenditures, and to refinance maturing debt, through external financing. The Utilities must obtain regulatory approval in Nevada in order to borrow money or to issue securities and will therefore be dependent on the PUCN to issue favorable orders in a timely manner to permit them to finance their operations, construction and acquisition costs and to purchase power and fuel necessary to serve their customers. We cannot assure you that the PUCN will issue such orders or that such orders will be issued on a timely basis.

***Our operating results will likely fluctuate on a seasonal and quarterly basis.***

Electric power generation is generally a seasonal business. In many parts of the country, including our service areas, demand for power peaks during the hot summer months, with market prices also peaking at that time. As a result, our operating results in the future will likely fluctuate substantially on a seasonal basis. In addition, we have historically sold less power, and consequently earned less income, when weather conditions in our service areas are milder. Unusually mild weather in the future could diminish our results of operations and harm our financial condition.

***Changes in consumer preferences, war and the threat of terrorism or epidemics may harm our future growth and operating results.***

The growth of our business depends in part on continued customer growth and tourism demand in the Las Vegas portion of our service area. Changes in consumer preferences or discretionary consumer spending in the Las Vegas portion of our service area could harm our business. We cannot predict the extent to which future terrorist and war activities, or epidemics, in the United States and elsewhere may affect us, directly or indirectly. An extended period of reduced discretionary spending and/or disruptions or declines in airline travel and business conventions could significantly harm the businesses in and the continued growth of the Las Vegas portion of our service area, which could harm our business and results of operations. In addition, instability in the financial markets as a result of war, terrorism or epidemics may affect our ability to raise capital.

## ITEM 1B. UNRESOLVED STAFF COMMENTS

SPR, NPC and SPPC have received no written comments regarding their periodic or current reports from the SEC staff that were issued 180 days or more preceding the end of their 2007 fiscal year and that remain unresolved**.**

## ITEM 2. PROPERTIES

Substantially all of NPC's and SPPC's property in Nevada and California is subject to the lien of the General and Refunding Mortgage Indentures dated as of May 1, 2001, between NPC and SPPC, respectively, and The Bank of New York, as trustee, as amended and supplemented.

The following is a list of NPC's share of electric generation plants including the type and fuel used to generate, the anticipated 2008 net capacity (MW), and the years that the units were installed.

| Plant Name | Type | Fuel | Number of Units | Winter MW Capacity | Summer MW Capacity | Commercial Operation Year |
|---|---|---|---|---|---|---|
| Clark [1] | Combined Cycle | Gas/Oil | 6 | 510 | 454 | 1979, 1979, 1980, 1982, 1993, 1994 |
| | Gas | Gas/Oil | 1 | 63 | 50 | 1973 |
| | Peakers | Gas | 2 | - | 413 | 2008 |
| Sunrise | Steam | Gas | 1 | 82 | 80 | 1964 |
| | Gas | Gas/Oil | 1 | 81 | 70 | 1974 |
| Harry Allen | Gas | Gas/Oil | 2 | 168 | 140 | 1995, 2006 |
| Chuck Lenzie [2] | Combined Cycle | Gas | 6 | 1,170 | 1,088 | 2006 |
| Silverhawk [3] | Combined Cycle | Gas | 3 | 440 | 410 | 2004 |
| Mohave [4][5] | Steam | Coal | 0 | 0 | 0 | 1971, 1971 |
| Navajo [6] | Steam | Coal | 3 | 255 | 255 | 1974, 1975, 1976 |
| Reid Gardner [7] | Steam | Coal | 4 | 325 | 316 | 1965, 1968, 1976, 1983 |
| Total | | | 29 | 3,094 | 3,276 | |

(1) The two combined cycles at Clark each consist of two gas turbines, two Heat Recovery Steam Generators (HRSG), and one steam turbine. In 1993 and 1994, the original four gas turbines (1979-1982) were combined with four new HRSGs and two new steam turbines to form the combined cycles. There are 2 Clark peaker blocks scheduled for completion in 2008 and the final 206 MW block will be available in 2008, but beyond NPC's summer peak.
(2) The two combined cycles at Lenzie each consist of two gas turbines, two HRSGs and one steam turbine.
(3) The acquisition of a 75% ownership interest in the Silverhawk power station from Pinnacle West was consummated in 2006. Southern Nevada Water Authority continues to hold a 25% ownership interest in the plant. The combined cycle plant consists of two gas turbines, two HRSGs and one steam turbine.
(4) Per a 1999 Consent Decree, Mohave ceased operation on December 31, 2005. The PUCN approved establishing regulatory accounts related to the shutdown and decommissioning. See Note 1, Summary of Significant Accounting Policies, of the Notes to Financial Statements for further discussion.
(5) Prior to the shut down, the total summer net capacity of the Mohave Generating Station was 1,580 MW. Southern California Edison is the operating agent and NPC has a 14% interest in the Station.
(6) NPC has an 11.3% interest in the Navajo Generating Station. The total capacity of the Station is 2,250 MW. Salt River Project is the operator (21.7% interest). There are four other partners: U.S. Bureau of Reclamation (24.3% interest), Los Angeles Dept. of Water & Power (21.2% interest), Arizona Public Service Co (14% interest), and Tucson Electric Power (7.5% interest).
(7) Reid Gardner Unit No. 4 is co-owned by the California Department of Water Resources (CDWR) (67.8%) and NPC (32.2%); NPC is the operating agent. NPC is entitled to 25 MW of base load capacity and 227 MW of peaking capacity from that Unit, subject to the following limitations: 1,500 hours/year, 300 hours/month, and 8 hours/day. The total summer net capacity of the Unit, subject to heat input limitation, is 252 MW. Reid Gardner Units 1, 2, and 3, subject to heat input limitations, have a combined net capacity of the Station is 291 MW. The Station summer capacity is 543 MW.

The following is a list of SPPC's share of electric generation plants including the type and fuel used to generate, the anticipated 2008 net capacity (MW), and the years that the units became operational.

| Plant Name | Type | Fuel | Number of Units | Winter MW Capacity | Summer MW Capacity | Commercial Operation Year |
|---|---|---|---|---|---|---|
| Ft. Churchill | Steam | Gas/Oil | 2 | 226 | 222 | 1968, 1971 |
| Tracy | Steam | Gas/Oil | 3 | 244 | 244 | 1963, 1965, 1974 |
| Tracy 4&5 [1] | Combined Cycle | Gas | 2 | 108 | 104 | 1996, 1996 |
| Tracy [2] | Combined Cycle | Gas | 3 | 578 | 541 | 2008 |
| Clark Mtn. CT's | Gas | Gas/Oil | 2 | 144 | 132 | 1994, 1994 |
| Valmy [3] | Steam | Coal | 2 | 252 | 252 | 1981, 1985 |
| Other [4] | Gas, Diesels | Propane, Oil | 13 | 57 | 56 | 1960-2008 |
| Total | | | 27 | 1,609 | 1,551 | |

(1) Tracy 4&5 were part of the Pinõn Pine Integrated Coal Gasification Combined Cycle power plant located at Tracy Station. This project was part of the Department of Energy's Clean Coal Demonstration Program. Although the coal gasification portion of the facility has never proven operational, the combined cycle unit has been operating on natural gas since 1996. The combined cycle consists of one combustion turbine, one HRSG, and one steam turbine. In 2003, SPPC installed duct burners, which added 15 MW of capacity.
(2) A new combined cycle at Tracy will consist of 2 gas turbines, 2 HRSGs and 1 steam turbine. It is scheduled to come online in 2008.
(3) Valmy is co-owned by Idaho Power Company (50%) and SPPC (50%); SPPC is the operator. The Plant has a total net capacity of 504 MW.
(4) As of December 31, 2007 there were 3 combustion turbines and 10 diesel units included in the "Other" category.

## ITEM 3. LEGAL PROCEEDINGS

### Sierra Pacific Resources and Nevada Power Company

*Merrill Lynch/Allegheny Lawsuit*

In May 2003, SPR and NPC filed suit against Merrill Lynch & Co., Inc. and Merrill Lynch Capital Services, Inc. (collectively, Merrill Lynch) and Allegheny Energy, Inc. and Allegheny Energy Supply Co., LLC (collectively, Allegheny) in the

United States District Court, District of Nevada, for compensatory and punitive damages of $850 million for causing the PUCN to disallow the approximate $180 million rate adjustment for NPC in its 2001 deferred energy case (as discussed in Note 3, Regulatory Actions of the Notes to Financial Statements). The PUCN held that NPC acted imprudently when it refused to enter into an electricity supply contract with Merrill Lynch and subsequently paid too much for electricity from another source. SPR and NPC allege that Merrill Lynch and Allegheny's fraudulent testimony and wrongful conduct caused the PUCN disallowance, among other allegations.

Merrill Lynch filed motions to dismiss in May 2003 and June 2003. Thereafter, the case was stayed pending resolution of NPC's appeal of the 2001 deferred energy case pending before the Nevada Supreme Court, which was decided in August 2006 and discussed further in Note 3, Regulatory Actions of the Notes to Financial Statements. The Nevada District Court has yet to rule on the motions to dismiss. In October 2006, the District Court approved a stipulation continuing a stay of the proceeding pending final resolution of the PUCN remand proceedings in the 2001 deferred energy case. In May 2007, SPR and NPC filed a motion to amend their complaint to reflect the Nevada Supreme Court's decision in the appeal and include additional damages (Motion to Amend). In June 2007, Allegheny and Merrill Lynch filed a motion in opposition to SPR and NPC's Motion to Amend before the Nevada District Court on the ground that the Utilities' recovery of the $189.9 million in rates under the PUCN Order on remand from the Nevada Supreme Court is all that SPR and NPC are entitled to recover and otherwise for failure to file a timely amended complaint (Motion in Opposition). In July 2007 the Court denied Allegheny and Merrill Lynch's Motion in Opposition and further set the case for trial in July 2008. In February 2008, the Defendants asked the Court to consider and rule on their originally filed motion to dismiss from 2003.

**Nevada Power Company and Sierra Pacific Power Company**

*Western United States Energy Crisis Proceedings before the FERC*

*FERC 206 complaints*

In December 2001, the Utilities filed ten complaints with the FERC against various power suppliers, including Enron, under Section 206 of the Federal Power Act seeking price reduction of forward wholesale power purchase contracts entered into prior to the FERC mandated price caps imposed in June 2001 in reaction to the Western United States energy crisis. The Utilities contested the amounts paid for power actually delivered as well as termination claims for undelivered power against terminating suppliers.

In June 2003, the FERC dismissed the Utilities' Section 206 complaints, stating that the Utilities had failed to satisfy their burden of proof under the strict public interest standard. In July 2003, the Utilities filed a petition for rehearing, but the FERC reaffirmed its June decision ("July decision"). The Utilities appealed this decision to the Ninth Circuit. In December 2006, a three judge panel of the Ninth Circuit overturned the July decision and remanded the case back to the FERC for application of the factors that the Ninth Circuit outlines in its decision. In May 2007, American Electric Power Service Corporation and Allegheny Energy Supply Company and other interested parties filed petitions for certiorari ("Petitions") with the U.S. Supreme Court seeking review of the Ninth Circuit's decision. The Utilities, together with other parties and the Federal Energy Regulatory Commission, filed their opposition to these Petitions in August 2007. In September 2007, the U.S. Supreme Court granted certiorari. Briefs have been submitted, oral argument was held in February 2008, and a decision should be issued by the summer of 2008.

The Utilities have negotiated settlements with Duke Energy Trading and Marketing, Reliant Energy Services, Inc., Morgan Stanley Capital Group, El Paso Merchant Energy (EPME), now known as El Paso Marketing L.P., Calpine Energy Services and Enron, but have been unable to reach agreement in bilateral settlement discussions with other respondents, including Allegheny, American Electric Power and BP.

**Nevada Power Company**

*Lawsuit Against Natural Gas Providers*

In April 2003, SPR and NPC filed a complaint in the U.S. District Court for the District of Nevada against several natural gas providers and traders. In July 2003, SPR and NPC filed a First Amended Complaint. A Second Amended Complaint was filed in June 2004, which named three different groups of defendants: (1) El Paso Corporation, El Paso Natural Gas Company, El Paso Merchant Energy, L.P., El Paso Merchant Energy Company, El Paso Tennessee Pipeline Company, El Paso Merchant Energy-Gas Company; (2) Dynegy Marketing and Trade; and (3) Sempra Energy, Sempra Energy Trading Corporation, Southern California Gas Company, and San Diego Gas and Electric. On December 13, 2005, the District Court dismissed SPR and NPC's claims. SPR and NPC appealed this decision to the Ninth Circuit Court of Appeals. Subsequently, SPR abandoned its appeal and the matter proceeded only with respect to NPC. In September 2007, the Ninth Circuit reversed the District Court's order. In November 2007, the Ninth Circuit denied the gas providers and traders' petition for rehearing. The Ninth Circuit has remanded the case to the District Court for further proceedings. In January 2008, the defendants refiled motions to dismiss, to which NPC responded in February 2008. Management cannot predict the timing or outcome of a decision on this matter.

**Sierra Pacific Power Company**

*Piñon Pine*

In its 2003 GRC, SPPC sought recovery of its unreimbursed costs associated with the Piñon Pine Coal Gasification Demonstration Project (the "Project"). The Project represented experimental technology tested pursuant to a Department of Energy (DOE) Clean Coal Technology initiative. Under the terms of the Project agreement, SPPC and DOE agreed to each fund 50% of construction costs of the Project. SPPC's participation in the Project had received PUCN approval as part of SPPC's 1993 integrated electric resource plan. While the conventional portion of the plant, a gas-fired combined cycle unit, was installed and performed as planned, the coal gasification unit never became fully operational. After numerous attempts to re-engineer the coal gasifier, the technology was determined to be unworkable. In its order in May 2004, the PUCN disallowed $43 million of unreimbursed costs associated with the Project. SPPC filed a Petition for Judicial Review with the Second Judicial District Court of Nevada (District Court) in June 2004 (CV04-01434). In January 2006, the District Court vacated the PUCN's disallowance in SPPC's 2003 GRC and remanded the case back to the PUCN for further review as to whether the costs were justly and reasonably incurred (Order). In March 2006, the PUCN appealed the Order to the Nevada Supreme Court (the "Supreme Court") and filed a motion to stay the Order pending the appeal to the Supreme Court. In June 2006, the District Court granted PUCN's motion to stay the Order. In July 2006, the Supreme Court issued an order questioning the finality of the District Court's decision and thus whether it has jurisdiction over the appeal and invited the parties to brief this matter. The BCP and PUCN responded in early August 2006. The Supreme Court dismissed the appeal in September 2006. Requests for rehearing were denied in late December 2006, and in January 2007, the matter was remitted back to the District Court, which, consistent with its January 2006 order, remanded the matter back to the PUCN for further review. The PUCN opened a docket to address the remand in April 2007. Briefs have been filed and a hearing was held in January 2008. An order from the PUCN is expected by the end of March 2008.

**Other Legal Matters**

SPR and it 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.

**Environmental**

**Nevada Power Company**

*Reid Gardner Station*

*Surface and Groundwater Matters*

Reid Gardner Station is a coal generating station consisting of four units. Unit no. 4 is co-owned by the California Department of Water Resources (CDWR) 67.8% and 32.2% by NPC. NPC is the operating agent.

Reid Gardner has a number of raw water and scrubber make-up storage ponds as well as ponds used for process water evaporation and fly ash settling. Process water, which has been used beyond the treatable limits, is routed to onsite ponds for evaporation. Waste management units are present throughout the site and surrounding area. Environmental contaminants identified at Reid Gardner include but are not limited to, elevated concentrations of total dissolved solids, sulfate, chloride, dissolved metals, volatile organic compounds and petroleum hydrocarbons.

In August 1999, the Nevada Department of Environmental Protection (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 ten years. This order also required NPC to submit a Site Characterization Plan to NDEP to ascertain impacts. This plan has been reviewed and approved by NDEP. In collaboration with NDEP, NPC has evaluated remediation requirements. In May 2004, NPC submitted a schedule of remediation actions to NDEP which included proposed dates for corrective action plans and/or suggested additional assessment plans for each specified area. Any future ponds will be double-lined with inter-liner leak detection in accordance with the NDEP Authorization to Discharge Permit issued October 2005.

Pond construction and lining costs to satisfy the NDEP order expended to date is approximately $45 million. Expenditures for 2008 are projected to be approximately $2.8 million, for a total expenditure of approximately $47.8 million.

Over the last two years, the water division of NDEP has been in discussions with NPC regarding what additional surface and groundwater cleanup may be required at the site, beyond the scope of the current pond relining project. The proposed solution was to enter into an Administrative Order on Consent (AOC) and the final form of the proposed AOC was delivered to NPC in December 2007. Until such time, NPC did not know the extent of the obligation or scope of work that would be required to effect site restoration due to the complexities associated with environmental remediation of the target media and the evolving standards of acceptable

remediation standards. As a result, management was unable to reasonably estimate the cost of this comprehensive remediation project prior to concluding the negotiations and receiving the final AOC from the NDEP.

In February 2008, NPC signed the AOC as owner and operator of Unit Nos. 1, 2 and 3 and as co-owner and Operating Agent of Unit No. 4. The AOC has been designed to supersede previous agreements for remedial activities at the site and takes a comprehensive approach to address historical environmental impacts associated with facility operations. Upon receiving the final document in December 2007, management was able to estimate a range of costs to satisfy the requirements of the AOC. As a result NPC has recorded as an asset retirement obligation in accordance with SFAS 143, Accounting for Asset Retirement Obligations as of December 31, 2007 of approximately $19.8 million, which it expects to receive regulatory recovery of, similar to other Asset Retirement Obligations. Other costs are expected to include capital expenditures and remediation costs of approximately $32.3 million and operating and maintenance expense of approximately $1.3 million. However, these estimates may vary significantly once the scope of work is initiated and additional characterization is completed.

*Air Quality Matters*

In June 2006, the EPA issued a Finding and Notice of Violation (NOV) related to monitoring, recordkeeping and emission exceedances at the Reid Gardner facility. In April 2007, NPC lodged a Consent Decree in federal district court with NDEP, EPA and the Department of Justice (DOJ) regarding the NOVs and providing for additional environmental controls and equipment changes, environmental benefit projects, monetary penalties, and/or other measures that will be required to resolve the alleged violations. Terms of the Consent Decree included a $1.1 million fine, which was paid during 2007, funding of projects, of which NPC expects to spend approximately $2 million for the Supplemental Environmental Project with the Clark County School District, and the installation of emission reduction equipment at the facility. The environmental project is aimed at achieving increased energy efficiency and cost savings for the school district. Certain environmental controls and equipment changes needed to assure compliance with existing or modified regulations, and which will satisfy the terms of the consent decree, were previously submitted by NPC to the PUCN in NPC's 2006 IRP filing. These expenditures were approved by the PUCN in late 2006 and include equipment installation on the various units to control startup opacity and particulates and reduce operating opacity and oxides of nitrogen. Capital expenditures are estimated at $84.0 million as approved by the PUCN; however, amounts may change depending on the procurement of material and services.

*Clark Station*

In May 2006, the EPA, by letter from the DOJ, notified NPC that it intended to initiate an enforcement action against NPC seeking unspecified civil penalties, together with injunctive relief, for alleged violations of the Prevention of Significant Deterioration requirements and Title V operating permit requirements of the Clean Air Act at Clark Station. NPC then entered into ongoing dialogue and settlement discussions with the EPA and DOJ regarding the alleged violations and in August 2007, a final Consent Decree between NPC and the EPA was entered with the Court. Terms of the Consent Decree include installation of an advanced NOx reduction burner technology on four existing units with an estimated cost of up to $60 million, which cost was previously submitted by NPC to the PUCN in its Second Amendment to the 2006 IRP filing and was approved in May 2007. Additionally, NPC paid a minimal fine and will make a contribution to Vegas Public Broadcasting Service (PBS) to fund a solar panel array on its new Educational Technology Campus planned in Clark County.

## ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

None.

## EXECUTIVE OFFICERS

The following are current executive officers of SPR, NPC and SPPC indicated and their ages as of December 31, 2007. There are no family relationships among them. Officers serve a term which extends to and expires at the annual meeting of the Board of Directors or until a successor has been elected and qualified:

Michael W. Yackira, 56, President and Chief Executive Officer, SPR

Mr. Yackira was elected to his current position on August 1, 2007. He was previously President and Chief Operating Officer from February 15, 2007 until August 1, 2007. Prior to that he held the positions of Corporate Executive Vice President and Chief Financial Officer from October 2004 to February 15, 2007. From December 2003 to October 2004 he held the position of Executive Vice President and CFO of SPR, as well as both NPC and SPPC. Mr. Yackira was previously Executive Vice President, Strategy and Policy, from January to December 2003. Previously he was the Vice President and CFO of Mars, Inc. from 2001 to 2002. Prior to that, he was with Florida-based FPL Group, Inc. from 1989 to 2000. Mr. Yackira is a certified public accountant.

Jeffrey L. Ceccarelli, 53, Corporate Senior Vice President, Service Delivery & Operations, SPR; President, SPPC

Mr. Ceccarelli was elected to his present position in October 2004. From June 2000 to October 2004 he held the position of President, SPPC. He previously held the position of Vice President, Distribution Services, New Business, in July 1999 for SPPC and NPC. A civil engineer, Mr. Ceccarelli has been with SPPC since 1972.

Roberto R. Denis, 58, Corporate Senior Vice President, Energy Supply, SPR

Mr. Denis was elected to his present position in October 2004. From August 2003 to October 2004 he held the position of Vice President, Energy Supply, for NPC and SPPC. From 2001 to 2003, he held the position of Vice President, Market & Regulatory Affairs, at FPL Energy, LLC. From 1999 to 2001, he held the position of Vice President of Market Services.

Stephen R. Wood, 64, Corporate Senior Vice President, Administration, SPR

Mr. Wood was elected to his present position in July 2004 and holds the same position at NPC and SPPC. He was previously President, Centaur Energy Development LLC, from 2000 to 2004. From 1997 to 2000 he served as President of Louisville Gas and Electric Company and President, Distribution Services, LG&E Energy Corp. concurrently. He was Executive Vice President and Chief Administrative Officer, LG&E Energy Corp. from 1994 to 1997. He is also a director of Martin Engineering, Inc.

Paul L. Kaleta, 52, Corporate Senior Vice President, General Counsel and Corporate Secretary, SPR

Mr. Kaleta was elected to his present position in February 2006, and holds the same position at NPC and SPPC. Previously he was General Counsel for Koch Industries, Inc. and various Koch subsidiaries from 1998 to 2005. Prior to that, he was Vice President and General Counsel of Niagara Mohawk Power Company for 8 years and, before that, in the private practice of law as an associate with Skadden, Arps, Slate, Meagher & Flom and as an associate and then equity member with Swidler Berlin, Chtd. (now Bingham McCutchen), both in Washington, D.C., for a total of 9 years.

William D. Rogers, 47, Corporate Senior Vice President, Chief Financial Officer and Treasurer, SPR

Mr. Rogers was elected to his current position on February 15, 2007. He was previously Vice President, Finance and Risk and Corporate Treasurer from November 14, 2006 to February 15, 2007. Prior to that, he was Corporate Treasurer from June 8, 2005 to November 14, 2006. Before joining SPR, he served as managing director of debt capital markets for Merrill Lynch & Co. in New York from 2000 to 2005. Prior to that, he served as managing director of debt capital markets with JP Morgan Chase in New York from 1992 until 2000.

Tony F. Sanchez, III, 42, Corporate Senior Vice President, SPR

Mr. Sanchez was elected to his current position on August 1, 2007. Mr. Sanchez will be named Corporate Senior Vice President, Public Policy and External Affairs at the end of February 2008. Prior to joining Sierra Pacific Resources, Mr. Sanchez was a partner in the Nevada based law firm of Jones Vargas. Prior to that, Mr. Sanchez served as executive assistant to Nevada's then-Governor Bob Miller in 1999. From 1995 to 1998, he held the position of assistant General Counsel for the Nevada Public Utilities Commission. From 1992 to 1995, he worked as associate legislative counsel in Washington, D.C handling energy and natural resource issues for Nevada's then-U.S. Senator Richard H. Bryan. Mr. Sanchez is also a director of the Las Vegas Latin Chamber of Commerce, a director of Paramount Bank of Nevada and a director of the Nevada and a director of the Nevada Tourism Alliance.

Donald L. "Pat" Shalmy, 67, Corporate Senior Vice President, Policy & External Affairs, SPR; President, NPC

Mr. Shalmy was elected to his present position in November 2004 and retired at the end of February 2008. From July 2002 to October 2004 he held the position of President, NPC. He was previously Senior Vice President, NPC since May 2002. Formerly he held the position of Director, Government and Community Relations at Kummer, Kaempfer, Bonner & Renshaw Ltd. Prior to that, Mr. Shalmy was County Manager of Clark County for 12 ½ years and President of the Las Vegas Chamber of Commerce for four years. He is also a director of the Las Vegas Monorail Company.

E. Kevin Bethel, 44, Corporate Vice President, Chief Accounting Officer, Controller, SPR

Mr. Bethel was elected as Corporate Vice President and Chief Accounting Officer of SPR on November 2, 2007, effective December 10, 2007. He was subsequently elected Corporate Controller of SPR as well as Vice President, Chief Accounting Officer, and Controller of NPC and SPPC on February 8, 2008. Prior to joining SPR, Mr. Bethel served as Assistant Controller for American Electric Power, Inc. (AEP), in Columbus, Ohio where he held management positions in accounting from 2001 to 2007. From 2000 to 2001, he held a management position with Central & South West Energy until they merged with AEP. Before that, he held accounting management positions with The Williams Company in 1999, Central & South West Services from 1994 to 1999 and the Public Service Company of Oklahoma from 1991 to 1994. Mr. Bethel is a certified public accountant.

Mary O. Simmons, 52, Vice President, External Affairs, SPPC

Ms. Simmons was elected to her current position in November 2004. From May 2001 to October 2004, she held the position of Vice President, Rates and Regulatory Affairs, for NPC and SPPC. Previously she held the position of Controller for SPR and SPPC since 1997 and held the same position with NPC beginning in 1999. Ms. Simmons is a certified public accountant and has been with SPR since 1985.

Robert E. Stewart, 60, Vice President, Marketing, SPR

Mr. Stewart was elected to his current position in February 2008. From January 1997 to February 2008, he worked as an independent consultant in several industries, including energy services and telecommunications. He was Vice President of Marketing for Florida Power and Light from June 1991 to November 1996. Prior to that, he worked at GTE for 19 years and was Vice President of Product Management at GTE Telephone Operations from June 1989 to June 1991.

## PART II

## ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES (SPR)

SPR's Common Stock is traded on the New York Stock Exchange (symbol SRP). Dividends paid per share and high and low sale prices of the Common Stock as reported by NYSE net for 2007 and 2006 are as follows:

| | Dividends Paid per share | | 2007 | | 2006 | |
|---|---|---|---|---|---|---|
| | 2007 | 2006 | High | Low | High | Low |
| First Quarter | $0.00 | $0.00 | $18.26 | $16.38 | $ 14.60 | $ 12.68 |
| Second Quarter | 0.00 | 0.00 | 19.60 | 16.87 | 14.35 | 12.68 |
| Third Quarter | 0.08 | 0.00 | 18.15 | 14.06 | 14.91 | 13.30 |
| Fourth Quarter | 0.08 | 0.00 | 17.76 | 14.89 | 17.50 | 14.29 |

Number of Security Holders:

| Title of Class | | Number of Record Holders |
|---|---|---|
| Common Stock: | $1.00 Par Value | As of February 22, 2008: 16,188 |

Dividends are considered periodically by the Board of Directors and are subject to factors that ordinarily affect dividend policy, such as current and prospective earnings, current and prospective business conditions, regulatory factors, SPR's financial condition and other matters within the discretion of the Board, as well as dividend restrictions set forth in SPR's 8.625% Senior Notes due 2014, 7.803% Senior Notes due 2012 and 6.75% Senior Notes due 2017.

On July 30, 2007, the Board declared a quarterly dividend on SPR's Common Stock of $0.08 per share. This dividend of approximately $17.7 million was paid on September 12, 2007, to shareholders of record on August 24, 2007. This is the first dividend paid on SPR's Common Stock since February 6, 2002 when the Board determined not to pay a dividend on SPR's Common Stock.

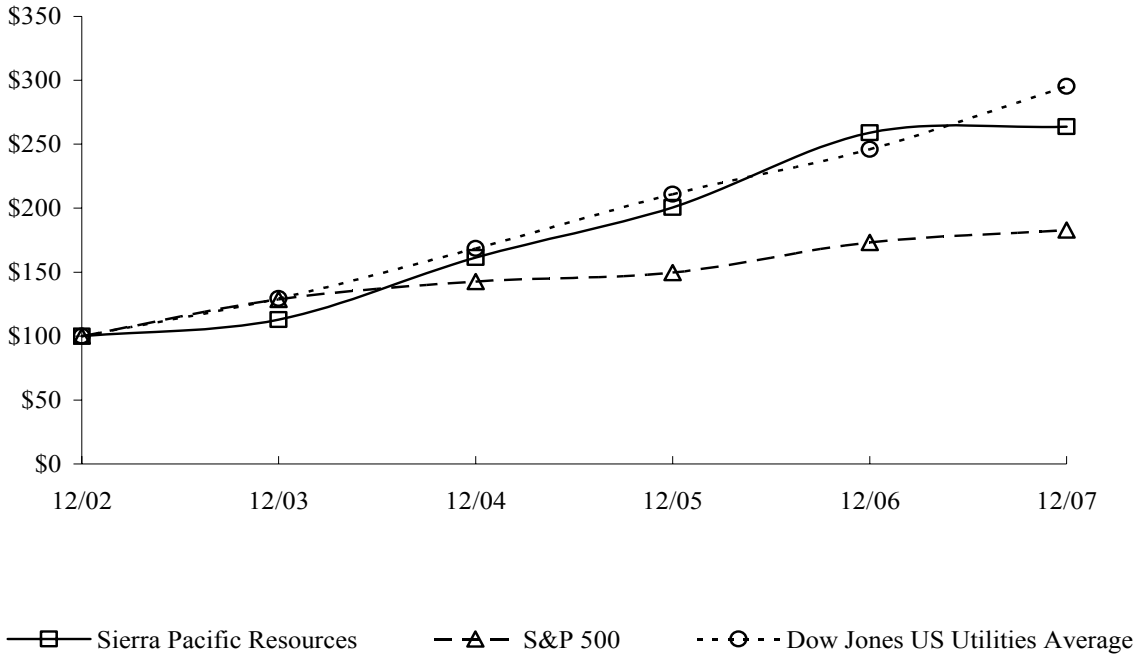
On November 1, 2007, the Board declared a quarterly dividend on SPR's Common Stock of $0.08 per share. This dividend of approximately $17.7 million was paid on December 12, 2007 to shareholders of record on November 19, 2007.

On February 7, 2008, SPR's Board of Directors declared a quarterly cash dividend of $0.08 per share payable on March 12, 2008, to common shareholders of record on February 22, 2008.

There is no guarantee that SPR will continue to pay dividends in the future, or that the dividends will be paid at the same amount or with the same frequency. See Note 8, Debt Covenant and Other Restrictions of the Notes to Financial Statements, for a description of the restrictions on NPC's and SPPC's ability to pay dividends to SPR and on SPR's ability to pay dividends on its common stock.

For information on the equity compensation plans, see Item 12.

**COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN***
**Among Sierra Pacific Resources, The S&P 500 Index**
**And The Dow Jones US Utilities Average Index**




* $100 invested on 12/31/02 in stock or index-including reinvestment of dividends. Fiscal year ending December 31.

## ITEM 6. SELECTED FINANCIAL DATA

See Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, for a discussion of factors that may affect the future financial condition and results of operations of SPR, NPC and SPPC.

**SIERRA PACIFIC RESOURCES**

| | Year ended December 31, (dollars in thousands; except per share amounts) | | | | |
|---|---|---|---|---|---|
| | 2007 | 2006[1] | 2005[2] | 2004[3] | 2003[4] |
| Operating Revenues | $ 3,600,960 | $ 3,355,950 | $ 3,030,242 | $ 2,824,796 | $ 2,787,543 |
| Operating Income | $ 414,567 | $ 488,797 | $ 358,678 | $ 333,858 | $ 260,314 |
| Net Income (Loss) Applicable to Common Stock | $ 197,295 | $ 277,451 | $ 82,237 | $ 28,571 | $ (140,529) |
| Net Income (Loss) Applicable to Common Stock Per Average Common Share - Basic and Diluted | $ 0.89 | $ 1.33 | $ 0.44 | $ 0.16 | $ (1.21) |
| Total Assets | $ 9,464,750 | $ 8,832,076 | $ 7,870,546 | $ 7,528,467 | $ 7,063,758 |
| Long-Term Debt | $ 4,137,864 | $ 4,001,542 | $ 3,817,122 | $ 4,081,281 | $ 3,579,674 |
| Dividends Declared Per Common Share | $ 0.16 | $ - | $ - | $ - | $ - |

(1) Income for the year ended December 31, 2006 includes reinstatement of deferred energy of approximately $116.2 million net of taxes and a $40.9 million net of taxes gain on the sale of Tuscarora Gas Pipeline Company's partnership interest in Tuscarora Gas Transmission Company.
(2) Income for the year ended December 31, 2005 includes a charge of $35.1 million net of taxes for the inducement of debt conversion and the reversal of $13.6 million net of taxes in interest charges as a result of settlements with terminated suppliers.
(3) Income for the year ended December 31, 2004 includes the reversal of $25.9 million net of taxes in interest expense due to the decision on the appeal of the Enron bankruptcy judgment and the write-off of $30.6 million net of taxes in disallowed plant costs at SPPC.
(4) Loss for the year ended December 31, 2003 was negatively affected by an unrealized net loss of $30.0 million net of taxes on the derivative instrument associated with the issuance of SPR's $300 million Convertible Notes, $59.1 million net of taxes write-off of deferred energy costs by NPC and SPPC and approximately $33.8 million net of taxes of interest charges related to the Enron litigation.

**NEVADA POWER COMPANY**

| | Year ended December 31, (dollars in thousands) | | | | |
|---|---|---|---|---|---|
| | 2007 | 2006[1] | 2005[2] | 2004[3] | 2003[4] |
| Operating Revenues | $ 2,356,620 | $ 2,124,081 | $ 1,883,267 | $ 1,784,092 | $ 1,756,146 |
| Operating Income | $ 297,304 | $ 351,272 | $ 228,827 | $ 216,490 | $ 183,733 |
| Net Income | $ 165,694 | $ 224,540 | $ 132,734 | $ 104,312 | $ 19,277 |
| Total Assets | $ 6,377,369 | $ 5,987,515 | $ 5,173,921 | $ 4,883,540 | $ 4,210,759 |
| Long-Term Debt | $ 2,528,141 | $ 2,380,139 | $ 2,214,063 | $ 2,275,690 | $ 1,899,709 |
| Dividends Declared - Common Stock | $ 25,667 | $ 48,917 | $ 35,258 | $ 45,373 | $ - |

(1) Income from continuing operations, for the year ended December 31, 2006 includes reinstatement of deferred energy of approximately $116.2 million net of taxes.
(2) Income for the year ended 2005 included the reversal of $11.5 million net of taxes in interest charges as a result of settlements with terminated suppliers.
(3) Income for the year ended December 31, 2004 included the reversal of $17.9 million net of taxes in interest expense due to the decision on the appeal of the Enron bankruptcy judgment.
(4) Income for the year ended December 31, 2003 included a $29.9 million net of taxes write-off of deferred energy costs and $23.4 million net of taxes of interest charges related to the Enron litigation.

**SIERRA PACIFIC POWER COMPANY**

| | Year ended December 31, (dollars in thousands) | | | | |
|---|---|---|---|---|---|
| | 2007 | 2006 | 2005[1] | 2004[2] | 2003[3] |
| Operating Revenues | $ 1,244,297 | $ 1,230,230 | $ 1,145,697 | $ 1,035,660 | $ 1,029,866 |
| Operating Income | $ 105,957 | $ 120,017 | $ 116,304 | $ 111,245 | $ 68,566 |
| Net Income (Loss) | $ 65,667 | $ 57,709 | $ 52,074 | $ 18,577 | $ (23,275) |
| Total Assets | $ 2,976,524 | $ 2,807,837 | $ 2,546,301 | $ 2,524,320 | $ 2,362,469 |
| Preferred Stock | $ - | $ - | $ 50,000 | $ 50,000 | $ 50,000 |
| Long-Term Debt | $ 1,084,550 | $ 1,070,858 | $ 941,804 | $ 994,309 | $ 912,800 |
| Dividends Declared - Common Stock | $ 12,833 | $ 24,619 | $ 23,933 | $ - | $ 18,530 |
| Dividends Declared - Preferred Stock | $ - | $ 975 | $ 3,900 | $ 3,900 | $ 3,900 |

(1) Income for the year ended December 31, 2005 income includes the reversal of $2.1 million net of taxes in interest expense as a result of settlements with terminated suppliers.

(2) Income for the year ended December 31, 2004 was affected by the write-off of $30.6 million net of taxes in disallowed plant costs and the reversal of interest expense of $8.0 million net of taxes due to the decision on the appeal of the Enron Bankruptcy judgment and a reduction to income tax expense of $2.1 million net of taxes as a result of a flow-through adjustment for pension funding.

(3) Loss for the year ended December 31, 2003 was affected by the write off of $29.3 million net of taxes in June 2003 of disallowed deferred energy costs and interest charges of $16 million related to the Enron litigation.

## ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

### Forward-Looking Statements

**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 future operations, business prospects, outcome of regulatory proceedings, market conditions and other matters.**

**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; NPC and SPPC are collectively referred to as the Utilities) to differ materially from those contemplated in any forward-looking statement include, among others, the following:**

**(1) the effect that changes in environmental laws or regulations as a result of current political efforts to address concerns about the possible effect that carbon dioxide and other "greenhouse gases" have on the environment, including the imposition of significant new limits on emissions from electric generating facilities, such as requirements to reduce greenhouse gases and/or other pollutants in response to climate change legislation or regulation, may have on our existing operations as well as on our construction program, especially the proposed Ely Energy Center;**

**(2) the effect that any construction risks may have on our business, such as the risk of delays in permitting, changes in environmental laws, securing adequate skilled labor, cost and availability of materials and equipment, including the escalating costs for materials, labor and environmental compliance in connection with the construction of coal generation facilities due to timing delays and other economic factors, equipment failure, work accidents, fire or explosions, business interruptions, possible cost overruns, delay of in-service dates, and pollution and environmental damage;**

**(3) whether the Utilities can procure sufficient renewable energy sources in each compliance year to satisfy the Nevada Portfolio Standard;**

**(4) changes in the rate of industrial, commercial and residential growth in the service territories of the Utilities, including the effect of weaker housing markets;**

**(5) unseasonable weather, drought and other natural phenomena, which could affect the Utilities' customers' demand for power, could seriously impact the Utilities' ability to procure adequate supplies of fuel or purchased power and the cost of procuring such supplies, and could affect the amount of water available for electric generating plants in the Southwestern United States;**

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

**(7) the ability and terms upon which SPR, NPC and SPPC will be able to access the capital markets to support their requirements for working capital, including amounts necessary for construction and acquisition costs and other capital expenditures, as well as to finance deferred energy costs, particularly in the event of unfavorable rulings by the Public Utilities Commission of Nevada (PUCN), untimely regulatory approval for such financings, and/or a downgrade of the current debt ratings of SPR, NPC, or SPPC;**

**(8) financial market conditions, including the effect of recent volatility in financial and credit markets, changes in availability of capital, or interest rate fluctuations resulting from, among other things, the credit quality of certain bond insurers that guarantee certain series of the Utilities' auction rate tax-exempt securities;**

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

**(10) unfavorable or untimely rulings in rate cases filed or to be filed by the Utilities with the PUCN, including the periodic applications to recover costs for fuel and purchased power that have been recorded by the Utilities in**

**their deferred energy accounts, and deferred natural gas costs recorded by SPPC for its gas distribution business;**

**(11) 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;**

**(12) whether the Utilities will be able to continue to pay SPR dividends under the terms of their respective financing and credit agreements and limitations imposed by the Federal Power Act;**

**(13) the discretion of SPR's Board of Directors regarding SPR's future common stock dividends based on the Board's periodic consideration of factors ordinarily affecting dividend policy, such as current and prospective financial condition, earnings and liquidity, prospective business conditions, regulatory factors, and restrictions in SPR's and the Utilities' financing agreements;**

**(14) 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;**

**(15) the final outcome of the proceedings to reverse the PUCN's 2004 decision on SPPC's 2003 General Rate Case (GRC), which disallowed the recovery of a portion of SPPC's costs, expenses and investment in the Piñon Pine Project;**

**(16) employee workforce factors, including changes in collective bargaining unit agreements, strikes or work stoppages;**

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

**(18) 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;**

**(19) 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; and**

**(20) unusual or unanticipated changes in normal business operations, including unusual maintenance or repairs.**

**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 of Sierra Pacific Resources (SPR) and its two primary subsidiaries, Nevada Power Company (NPC) and Sierra Pacific Power Company (SPPC), collectively referred to as the "Utilities" (references to "we," "us" and "our" refer to SPR and the Utilities collectively), and includes the following:

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

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

The Utilities are regulated by the PUCN and, for the California service territory of SPPC, the California Public Utilities Commission (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 generation, distribution and transmission operations. The FERC has jurisdiction under the Federal Power Act with respect to wholesale 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 Utilities' revenues and operating income are subject to fluctuations during the year due to impacts that seasonal weather, rate changes, and customer usage patterns have on demand for electric energy and resources. NPC is a summer peaking utility experiencing its highest retail energy sales in response to the demand for air conditioning. SPPC's electric system peak typically occurs in the summer, while its gas business typically peaks in the winter. The variations in energy usage by the Utilities' customers due to varying weather and other energy usage patterns necessitates a continual balancing of loads and resources and purchases and sales of energy under short and long term contracts. As a result, the prudent management and optimization of available resources has a direct effect on the operating and financial performance of the Utilities. Additionally, the recovery of purchased power and fuel costs, and other costs, on a timely basis, and the ability to earn a fair return on investments are essential to the operating and financial performance of the Utilities.

### Overview of Major Factors Affecting Results of Operations

During 2007, SPR's net income applicable to common stock was $197.3 million compared to $277.5 million in 2006. Earnings were lower in 2007 primarily as a result of the reinstatement of deferred energy in 2006 of approximately $116.2 million net of taxes and the $40.9 million gain on sale (net of taxes), recorded in 2006, of the partnership interest in Tuscarora Gas Transmission Company (TGTC) held by Tuscarora Gas Pipeline Company's (TGPC), a wholly owned subsidiary of SPR. Partially offsetting this was:

- an increase in gross margin in 2007, exclusive of Reinstatement of Deferred Energy (as defined under NPC's and SPPC's respective, Results of Operations) of almost 18% at NPC. See discussion of gross margin in NPC and SPPC's, respective Results of Operations;
- settlement in 2007 with the PUCN regarding accrued interest on NPC's 2001 deferred energy case;

- an increase in 2007 in AFUDC and allowance for borrowed funds used during construction due to the construction of NPC's Clark Peaking Units and SPPC's Tracy Generating Station; and
- a decrease in 2007 in interest charges.

During 2006, SPR's net income applicable to common stock was $277.5 million compared to $82.2 million in 2005. The increase in earnings was primarily due to the following items (after income taxes):

- the July 2006, Nevada Supreme Court ruling which allows NPC to recover approximately $180 million ($116.2 million, net of tax) of the previously disallowed deferred energy costs (for further discussion of this legal proceeding, see Note 3, Regulatory Actions of the Notes to Financial Statements);
- the $40.9 million gain on sale, recorded in 2006, of the partnership interest in TGTC held by TGPC, a wholly owned subsidiary of SPR;
- improved operating income (excluding the approximate $180 million reinstatement);
- other income of $21.7 million for the carrying charge on Lenzie;
- early tender fees of $6.9 million for the extinguishment of $85 million of SPR's 8.625% Senior Notes and $25 million of SPR's 7.803% Senior Notes; and
- a charge recorded in 2005 for $35.1 million in early debt conversion fees associated with SPR's convertible notes.

**2007 Key Objectives**

SPR and the Utilities focused on the following key objectives during 2007:

- owning more generating facilities; reducing dependence on purchased power;
- diversifying fuel mix, including the use of renewable energy and energy efficiency and conservation programs;
- continuing proactive management of energy risk;
- maintaining a positive relationship with our regulators;
- strengthening our balance sheet; and
- improving liquidity and improving our credit ratings.

**2007 Accomplishments**

*Investments in and Optimization of Generating Assets*

In 2003, NPC and SPPC embarked on a strategy to build or acquire generating facilities, reduce dependence on purchased power and diversify fuel mix. Since 2003, the Utilities have either purchased or completed construction of generating facilities or peaking units with a summer capacity of 1,574 MWs. In conjunction with the generation facilities, the Utilities have constructed 662 miles of transmission lines, and with the construction of the Ely Energy Center, anticipates the additional construction of a transmission line that will connect Southern Nevada with Northern Nevada. In 2007, NPC began construction of 619 MWs of natural gas-fired combustion turbine peaking units at Clark Station expected to be in service for the summers of 2008 and 2009 at an approximate cost of $403.4 million. Additionally, in December 2007, NPC began construction of a 500 MW Natural Gas Generating Station at the existing Harry Allen Site, subject to PUCN approval.

SPPC continues to construct a 541 MW gas fired high efficiency combined cycle generator at the Tracy Plant. SPPC anticipates an in-service date of June 2008. SPPC has included the cost of the estimated $421 million investment for the plant, along with the annual operating and maintenance and depreciation costs in its 2007 GRC under the hybrid test year methodology. The unit will provide needed generation within SPPC's control area to reliably serve the growing needs of Northern Nevada.

*Management of Energy Risk*

The Utilities purchase not only coal, natural gas, and oil to operate generating plants, but also wholesale power to meet the energy requirements of their customers. The Utilities have also invested in and maintain extensive transmission systems that allow the Utilities to move energy for their customers' needs. While the Utilities have greatly reduced their dependence on wholesale power markets to meet their customers' needs, they continue to tap the open energy markets as part of an effort to manage their portfolio of generation resources, load obligations, and purchased power and fuel contracts. This exposes the Utilities to energy risk and uncertainty in relation to cash flow requirements for fuel and wholesale power, the expenses that may be incurred as a result of energy procurement efforts, and the rates needed to recover those costs.

The Utilities systematically identify, quantify, manage, and control energy-related risks primarily through organization and governance, energy risk management programs, and energy risk control practices. In 2007, there were no fuel and purchased power costs disallowed, and the Utilities' energy supply plans received PUCN approval. Policies and procedures approved by corporate-level risk committees facilitate the prudent purchase or sale of short-term and forward energy products and financial instruments, and limit energy risk to levels consistent with PUCN-approved energy supply plans, with the goal of reducing fuel and purchased power costs to ratepayers, subject to reliability and price risk considerations. The Utilities follow approved energy supply plans that

encompass the reliable and efficient operation of the Utilities' owned generation, the procurement of all fuels and purchased power, and resource optimization. The energy supply plans include assessments of projected loads and resources, assessments of expected market prices, evaluations of relevant supply portfolio options available to the Utilities, and evaluations of the risk attributable to those supply portfolio options.

Financial instruments for hedging in conjunction with energy purchases and sales are also used to mitigate energy risks. In 2007, the Utilities continued to comply with the stipulated gas hedging plan.

*Regulatory*

In 2007, the Utilities filed several rate cases which resulted in increased rates and more timely recovery of fuel and purchased power expenses. As of December 31, 2007, the Utilities have decreased their deferred energy balances from $550 million in 2006 to a balance of $252 million in 2007, significantly reducing the Utilities' exposure to recovery of past fuel and purchased power costs. Among the major accomplishments in 2007 were approval of NPC's 2006 GRC which increased general rates 5.66%, or $120.1 million; approval of NPC's Western Energy Crisis Rate Case, which allowed the recovery of approximately $83.6 million, plus a carrying charge over three years for deferred settlement and legal costs associated with power supply contracts terminated during the Western Energy Crisis; settlement of NPC's 2001 Deferred Energy case which allowed NPC to recover in rates $189.9 million over ten years; and various Deferred Energy and BTER filings with no disallowances. However, SPPC was not able to recover all settlement costs associated with the Western Energy Crisis. In November 2007, the PUCN disallowed approximately $7.6 million (net of taxes) with respect to SPPC's Western Energy Crisis Rate Case.

*Further Broaden Access to Capital*

SPR's and the Utilities' capital strength continued to improve in 2007. SPR's cash from operating activities increased significantly in 2007, which enabled it to meet its operating cash needs plus contribute to the funding of various capital projects. The Utilities' senior secured debt achieved investment grade status by three of the four major rating agencies. As a result, cost of borrowing under the Utilities' revolving credit facilities will likely be reduced. In addition, the upgrades have the potential to provide SPR and the Utilities better access to capital markets and to reduce the cost of issuing additional long-term debt. Furthermore, in September 2007, SPR, as a well known seasoned issuer, together with NPC and SPPC filed a form S-3 shelf registration statement covering securities of SPR and the Utilities, which is expected to provide SPR and the Utilities with more timely access to the capital markets. However, disruptions in the banking and capital markets not specifically related to SPR or the Utilities may affect their ability to access funding sources or cause an increase in the return required by investors. The Utilities have a stronger capital structure as a result of certain financings, and the equity offer of 12 million shares of common stock by SPR in December 2007, resulting in net proceeds of $202.8 million, which was used to invest in the Utilities. Furthermore, management believes that the Utilities' cash on hand, the use of the Utilities' revolving credit facilities and the ability to issue debt of approximately $1.1 billion as of December 31, 2007, provides sufficient liquidity for the Utilities to meet their financial obligations. Finally, the restoration of the dividend on SPR's common stock was a major milestone in 2007, as dividends had not been paid since February 2002.

**2008 and Beyond Outlook**

In the Western and Southwest portions of the United States, energy needs continue to increase; however, the development of generating facilities by utility companies has decreased. As a result, the cost of energy and natural gas continues to rise with increased demand and the decline in the ability to meet those demands. The economics of this situation coupled with variations in weather, the capabilities and limits on the Utilities owned generating facilities, transmission constraints, regulations, and changes and potential changes in environmental law are a significant business issue for the Utilities. As a result, the Utilities' strategies, as evidenced by their Integrated Resource Plans (IRP), are aimed at reducing dependence on purchased power by the use of energy efficiency and conservation programs and diversifying fuel mix, including renewable energy and owning more generating facilities.

**2008 Key Objectives**

- Management of Energy Resources
  - Energy Efficiency and Conservation Programs
  - Purchase and Development of Renewable Energy Projects
  - Construction of Generating Facilities
  - Management of Energy Risk, including fuel and purchased power costs
- Management of Environmental Matters
- Management of Regulatory Filings
- Further Broaden Access to Capital

*Management of Energy Resources*

Energy Management encompasses energy efficiency and conservation programs, diversification of fuel mix, optimization of generation assets, management of energy risk which includes the purchase of short term and long term supply contracts, transmission, storage, reliability and efficiency, and regulatory and legal considerations. The ability to balance and optimize these functions is a significant business challenge that we face. In 2008, NPC anticipates the completion of 619 MWs peaking units at the Clark Generating Station.

*Energy Efficiency and Conservation Programs*

As discussed earlier, a part of our strategy to reduce dependence on purchased power is to manage our resources against our load requirements with energy efficiency and conservation programs. As such, in 2007 NPC implemented new and expanded qualified conservation programs (Demand Side Management or "DSM"), which were approved by the PUCN in 2006. Also, in 2007, SPPC obtained budget approval from the PUCN to significantly increase its DSM program for the years 2008-2010. As part of the Clinton Global Initiative, the Utilities' have committed to spending approximately $135 million over the next three years towards increasing efficiency and qualified conservation programs. NPC and SPPC have received PUCN approval of approximately $73.6 million and $29.8 million, respectively and an additional $36.9 million is pending PUCN approval as part of NPC's 5$^{th}$ amendment to its Integrated Resource Plan (IRP) for the years 2008- 2010. The PUCN approval of the DSM budget increase was a key step in expanding the energy savings yield from the DSM programs.

NPC and SPPC have designed a portfolio of cost effective DSM programs that allow every customer to take advantage of savings from energy efficiency measures. DSM programs are marketed across all segments of customer classes (residential, commercial, public, and low income). After the DSM percentage allowance is fully utilized, NPC's and SPPC's strategy is to continue to implement cost-effective DSM programs.

Furthermore, the Portfolio Standard, discussed below, allows energy efficiency measures from qualified conservation programs to meet up to 25% of the Portfolio Standard. A portfolio energy credit is created for each kWh of energy conserved by qualified energy efficiency programs. Energy saved during peak demand hours earns double the portfolio energy credits.

*Purchase and Development of Renewable Energy Projects*

The Utilities have embarked on a strategy to invest in renewable energy that, along with purchased power contracts and an increase in DSM programs, will enhance the opportunity for the Utilities to fully meet the Portfolio Standard as required by Nevada law. The Utilities' compliance with the Portfolio Standard is dependent on the availability of renewable energy resources. NPC's current capital budget includes investing approximately $457 million for renewable energy projects over the next five years.

Nevada law sets forth the renewable energy portfolio standard (Portfolio Standard) requiring providers of electric service to acquire, generate, or save a specific percentage of its total retail energy sales from renewable energy resources (Renewables). Renewables include biomass, geothermal, solar, waterpower and wind projects. In 2007, the Utilities were required to obtain 9% of their total energy from Renewables. The Portfolio Standard increases by 3% every other year until it reaches 20% in 2015. Moreover, not less than 5% of the total Portfolio Standard must be met from solar resources.

Nevada law requires providers of electric services to file an annual report that describes the level of compliance with the Portfolio Standard. In the Utilities' April 2007 Portfolio Standard Annual Report for Compliance Year 2006 (submitted to the PUCN jointly), NPC reported that with PUCN approval of a sale and purchase of SPPC's excess non-solar PCs, NPC met the non-solar Portfolio Standard. SPPC reported compliance with the non-solar component of the Portfolio Standard. However, due to lack of availability, the Utilities did not meet the solar portion of the Portfolio Standard. Additionally, the report described the Utilities ongoing activities to reach full compliance with the Portfolio Standard in the near future.

In December 2007, the PUCN issued its Order accepting the Utilities' Portfolio Standard Annual Report for Compliance Year 2006 and accepted a stipulation that granted an exemption from meeting the Portfolio Standard. In addition, because the Utilities' took reasonable efforts to comply with the Portfolio Standard, the PUCN waived any administrative fines or penalties for non compliance.

In 2007, NPC's and SPPC's energy portfolio included 90.6 MWs and 184.0 MWs, respectively of renewable energy and associated portfolio energy credits from long term purchase power contracts with renewable providers. In addition, NPC and SPPC have contracts with similar renewable energy providers for 287.9 MWs and 27.4 MWs, respectively, which are currently under development.

*Construction of Generating Facilities*

*Ely Energy Center*

Included in the PUCN's approval of the IRP is Phase 1 of the construction of the Ely Energy Center that consists of two 750 MW coal generation units to be located near Ely, Nevada. In addition to the generation units, the PUCN approved the development and construction of a 250-mile 500 kilovolt (kV) transmission line that would deliver electricity from the Ely Energy Center and from any possible future renewable resource projects in the area, as well as link NPC's and SPPC's transmission systems in the southern and northern portions of the state. The PUCN approved spending up to $300 million for development activities associated with the Ely Energy Center and transmission line; however, the PUCN placed a $155 million spending limit until the appropriate permits, as discussed below, are obtained. For planning purposes, it is currently assumed that the capacity of the project, as well as the development and construction costs, would be shared by NPC and SPPC on an 80% - 20% basis, respectively. The PUCN established the project as a "critical facility," thereby allowing it to qualify for incentives that will be determined in a later filing. NPC and SPPC are required to file amendments to their IRPs once elements of the plan, including final costs and timing of completion, can be more accurately estimated. The Utilities expect to file an amendment to their IRP in 2008. The total project costs are estimated to be approximately $5.0 billion if construction were to begin at the time of this filing. Depending on the timing of construction, negotiation of certain contracts, the potential initiation of any litigation challenging the project, and the timing and terms of permitting, among other factors, actual costs, scope, and timing of the completion of the project will likely differ materially from initial estimates.

In addition to PUCN approval and other factors, the timing and construction of the Ely Energy Center and transmission line are dependent on obtaining land use permits from the Bureau of Land Management and air permits from the Nevada Division of Environmental Protection (NDEP). On October 31, 2007, the NDEP published a notice of intent to issue a Class I air quality permit, together with a draft operating permit, with respect to the Ely Energy Center. The draft operating permit was subject to public comment, the comment period having ended on January 23, 2008. The NDEP will be responding to all public comments and upon completion the Utilities expect a final air quality permit will be issued. Possible changes to state and federal environmental laws or regulations, including those relating to carbon emissions from coal-fired power plants, could impact either permitting process and thereby affect the Utilities' ability to proceed or could require design changes to the project overall. At this time we are unable to predict the timing or outcome of the permitting processes.

Additionally, due to concerns about the possible effect of carbon dioxide and other "greenhouse gases" on the environment, and particularly on climate change, there is considerable debate both at a local level and in Congress as to whether or not additional coal-fired generating stations should be built in the United States. For example, U.S. Senator Harry Reid from the State of Nevada, Majority Leader of the U.S. Senate, has voiced objections to the construction of coal generating facilities in Nevada, including the Ely Energy Center. Moreover, there are many legislative and rulemaking initiatives pending at the federal and state level which are aimed at the reduction of greenhouse gas emissions. While the Utilities believe that the Ely Energy Center represents the best alternative for meeting the increasing electricity requirements of the State of Nevada, the Utilities cannot predict the outcome of pending or future legislative and rulemaking proposals, their effect on the permitting requirements for the Ely Energy Center described above, or their effect otherwise on the project overall, including future PUCN review and approval. It is possible that the adoption of one or more such legislative or regulatory proposals could trigger a need to reevaluate the feasibility, economic and otherwise, of the Ely Energy Center as a coal generating facility or other aspects of the project overall.

If the Ely Energy Center is delayed, or if the current planning assumptions for the project change materially, the Utilities would need to explore alternative sources of power for meeting the projected electricity demand in their service territories. The most likely alternative to coal generation would involve increased use of natural gas, either through increased use of natural gas fueled purchased power or the construction of additional Utility-owned natural gas generating facilities, or a combination of both. Such increased use of natural gas likely would further subject the Utilities and their customers to natural gas price volatility, as well as to any potential regional supply adequacy issues.

*Natural Gas Generating Units*

NPC has begun the construction of 619 MWs of natural gas-fired combustion turbine peaking units at Clark Station expected to be in service in 2008 at an approximate cost of $403.4 million. Additionally, in 2007, NPC began construction of a 500 MW natural gas generating station at the existing Harry Allen Station, which remains subject to PUCN approval.

SPPC continues to construct a 541 MW gas fired high efficiency combined cycle generator at the Tracy Plant. SPPC anticipates an in-service date of mid 2008.

*Management of Energy Risk*

Entering 2008, the Utilities expect to have open positions resulting from the management of their portfolio of generation resources, load obligations, and purchased power and fuel contracts, in the context of unfolding developments in regional energy markets. The risks associated with the open positions are addressed in various ways. The Utilities implement a prudent strategy of

piecemeal procurements transacted in regular intervals and completed before the start of the peak summer season. This provides the Utilities with ample opportunities for optimizing their portfolio on a rolling basis in anticipation of changes in system conditions, load forecasts, and regional energy market fundamentals. The Utilities also coordinate the planned maintenance schedules of their owned generating plants and transmission facilities with expectations of start dates of new generating plants or purchased power contracts.

*Management of Environmental Matters*

The impact environmental laws can have on existing generating facilities and current and prospective capital construction projects include but are not limited to increased costs, closure of existing facilities, mandated equipment upgrades, and termination of the construction of facilities. Environmental laws already affect the energy we buy as discussed above under *Purchase and Development of Renewable Energy Projects*. In the next five years, NPC is projected to spend $214.3 million on certain major environmental projects/upgrades. Additionally, as discussed above, under *Construction of Generating Facilities, Ely Energy Center*, environmental laws will play a significant role in the construction of Ely Energy Center.

A key objective for the Utilities in 2008 will be to enhance and maintain our energy infrastructure investments in ways that meet customer demand for reliable energy in an efficient and environmentally responsible manner. The Utilities believe that a diverse and balanced portfolio of energy resources represents opportunity for reliability and cost control, yet are also mindful of our overriding environmental responsibility. The Utilities are committed to making technology choices with a primary focus on limiting emissions and optimizing our investments so that prices remain competitive. To meet the growing demand for power, the Utilities are investing in a new generation of highly efficient and environmentally advanced power plants, both coal and natural gas fired as well as adding new environmental controls to their existing plants. To help manage load demand, the Utilities are also increasing their participation and development of new energy efficiency and demand side conservation programs.

*Management of Regulatory Filings*

As is the case with most regulated entities, the Utilities are frequently involved in various regulatory proceedings. The Utilities are required to file for quarterly rate adjustments to provide recovery of their fuel and purchased power costs. They are also required to file rate cases every three years to adjust general rates that include their cost of service and return on investment in order to more closely align earned returns with those allowed by regulators. Furthermore, the Utilities are required to file a triennial IRP which is a comprehensive plan that considers customer energy requirements and proposes the resources to meet that requirement. Resource additions approved by the PUCN in the resource planning process are deemed prudent for ratemaking purposes. Between IRP filings, the Utilities may seek PUCN approval for modifications to their resource plans and for power purchases. Major projects included in the Utilities' IRPs include the Ely Energy Center, Tracy Generating Station, and Clark Station. The 500 MW project at Harry Allen has not been approved in the IRP, but NPC will file an amendment to its IRP in March 2008 requesting approval. The Utilities incur costs for such items as deferred fuel and purchased power costs, operations and maintenance and capital projects; however, costs are not recovered through rates until approved by regulators, the timing between costs incurred and recovery is considered regulatory lag. As such, timely and accurate filings of these various rate cases is essential to the Utilities' operating and financial performance as it reduces regulatory lag, which has a direct effect on the cash flows of the Utilities. Furthermore, the timing of the filings/decisions can affect the timing of construction and thus the economic benefits. As a result, the Utilities file quarterly BTER updates to minimize exposure to changes in fuel and purchased power expense, file amendments to IRP's as changes in resource needs occur, and may use a "hybrid" test year for general rate filings as was the case with SPPC's 2007 GRC which allows projected costs that are known and measurable to be included in rates so long as the expense has begun to be incurred prior to the rate effective date. The "hybrid" test year helps to reduce regulatory lag between rate case filings, particularly in the case of major construction projects and related operating and maintenance expense, where significant amounts of capital are required.

Significant decisions or filings expected in 2008 include, but are not limited to, a decision in SPPC's 2007 GRC, amendments to the Utilities' IRPs which may include the further approval of the Ely Energy Center and the filing of NPC's GRC in late 2008.

*Further Broaden Access to Capital*

In 2007, the Utilities generated sufficient cash to meet their operating needs and contribute to capital projects. A significant focus in 2008 will again be to generate sufficient cash from operations to meet their operating needs and contribute to capital projects by managing recovery of deferred fuel and purchased power costs, reducing regulatory lag in recovery of costs and controlling costs. However, significant amounts of capital may be necessary to fund existing and prospective construction projects, as well as volatile energy costs. The Utilities' estimated cash requirement for 2008 is $1.2 billion and $7.6 billion over the next five years for capital projects, some of which include the Ely Energy Center for $2.4 billion (does not include costs beyond 2012), Tracy for $43.6 million, Clark Station for $131.3 million, Harry Allen for $681.9 million, renewable development of $457 million and environmental upgrades of $214.3 million. Of these major projects approximately $930 million has been approved by the PUCN. Management may be required to meet such financial obligations with a combination of internally generated funds, the use of the Utilities' revolving credit facilities, the issuance of long-term debt, and/or capital contributions from SPR. If energy costs rise at a rapid rate and the Utilities do not recover the cost of fuel and purchased power in a timely manner, the Utilities may need to issue additional debt to support their operating costs or delay capital expenditures.

## CRITICAL ACCOUNTING POLICIES AND ESTIMATES

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

### Regulatory Accounting

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

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

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

#### *Deferred Energy Accounting*

Under deferred energy accounting, to the extent actual fuel and purchased power costs exceed fuel and purchased power costs recoverable through current rates, the excess is not recorded as a current expense on the statement of operations but rather is deferred and recorded as an asset on the balance sheet. Conversely, a liability is recorded to the extent fuel and purchased power costs recoverable through current rates exceed actual fuel and purchased power costs. These excess amounts are reflected in adjustments to rates and recorded as revenue or expense in future time periods, subject to PUCN approval. Nevada law 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." Nevada law specifies that fuel and purchased power costs include all costs incurred to purchase fuel, to purchase capacity, and to purchase energy. Both Utilities are entitled under statute to utilize deferred energy accounting for their electric operations and both Utilities accumulate amounts in their deferral of energy costs accounts. The Utilities also record, and are eligible under the statute to recover, a carrying charge on such deferred balances, recognized as interest income in the current period.

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

See Note 3, Regulatory Actions of the Notes to Financial Statements, for additional discussion of the regulatory process to recover these deferred costs.

**Accounting for Derivatives and Hedging Activities**

SPR, NPC and SPPC apply SFAS 133, "Accounting for Derivative Instruments and Hedging Activities," as amended ("SFAS 133"). SFAS 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. The accounting for derivatives depends on the intended use of the derivatives and the resulting designation.

*Fuel and Purchased Power Contracts*

In order to manage loads, resources and energy price risk, the Utilities enter into forward contracts to purchase or sell a specified amount of energy at a specified time, or during a specified period, in the future. In addition to forward fuel and power contracts, the Utilities also use over-the-counter options with financial institutions and other energy companies to manage price risk. All of these instruments are considered to be derivatives under SFAS 133 and are marked to market in the statement of financial position unless the contract qualifies for the normal purchases or sales exemption per the criteria in SFAS 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 options and these forward fuel and power contracts and other energy related derivative instruments.

In conjunction with the issuance of SFAS 133, the Public Utilities Commission of Nevada (PUCN) and in the case of SPPC, the California Public Utility Commission (CPUC) issued accounting orders authorizing the Utilities to offset any derivative assets or liabilities with a regulatory asset or liability. This accounting treatment is intended to defer the recognition of mark to market gains and losses on energy commodity transactions until the period of settlement. The orders provide for the Utilities to not recognize the unrealized gain or loss on utility derivative commodity instruments in the statement of operations and comprehensive income. Fuel and purchased power costs are subject to this accounting order and apply deferred energy accounting. Upon settlement of a derivative instrument, actual fuel and purchased power costs are recognized in the period of settlement if 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. The fair value of the Utilities' derivative commodity instruments, which are recorded on the Consolidated Balance Sheets, are sensitive to market price fluctuations that can occur on a daily basis.

*Interest Rate Risk*

SPR, NPC and SPPC are subject to risk of fluctuating interest rates in the normal course of business. We manage interest rate risk by taking advantage of market conditions when timing the issuance of long-term debt financings. In 2007, SPPC entered into and settled three forward-starting interest rate swaps and NPC entered into and settled an interest rate lock agreement to manage the risk associated with changes in and the impact on future interest rate payments. SPPC received a payment of $11.3 million from the counterparty and recorded the amount as a premium on long term debt and NPC made a payment to the counterparty of $546 thousand and recorded the amount as a discount on long term debt. The amounts are being amortized over the life of the debt in accordance with regulatory accounting practices under SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" ("SFAS 71"). There were no forward-starting swap and interest rate lock agreements outstanding as of December 31, 2007.

**Accounting for Income Taxes**

As of December 31, 2007, the deferred tax asset for net operating losses (NOLs) and tax credit carryovers was $52.9 million. The NOLs and tax credit carryovers may be utilized in future periods to reduce taxes payable to the extent that SPR and the Utilities recognize taxable income.

The following table summarizes as of December 31, 2007 the NOL and tax credit carryovers and associated carryover periods, and valuation allowance for amounts which SPR has determined that realization is uncertain (dollars in thousands):

| | Deferred Tax Asset | Valuation Allowance | Net Deferred Tax Asset | Expiration Period |
|---|---|---|---|---|
| Federal NOL | $ 20,992 | $ - | $ 20,992 | 2020-2023 |
| State NOL | 127 | - | 127 | 2008-2013 |
| Research and development credit | 5,465 | - | 5,465 | 2021-2025 |
| Alternative minimum tax credit | 25,241 | - | 25,241 | indefinite |
| Arizona state coal credits | 1,100 | 588 | 512 | 2008-2012 |
| Total | $ 52,925 | $ 588 | $ 52,337 | |

At December 31, 2007, the Utilities had gross federal and state NOL carryovers of $60.0 million and $1.4 million, respectively.

Considering all positive and negative evidence regarding the utilization of the Utilities' deferred tax assets, it has been determined that the Utilities are more likely than not to realize all recorded deferred tax assets, except for the Arizona coal tax credits. As such, these Arizona coal tax credits represent the only valuation allowance that has been recorded as of December 31, 2007.

**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 Department of Air Quality and Environmental Management (DAQEM) 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 any 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.

Depending on whether environmental liabilities occurred from normal operations or as part of new environmental laws, the Utilities accrue for environmental remediation liabilities in accordance with SFAS 143, Accounting for Asset Retirement Obligations (SFAS 143) or Statement of Position 96-1 Environmental Remediation Liabilities (SOP 96-1). Estimated costs from environmental remediation obligations generally are recognized no later than completion of the remedial feasibility study or when the criteria for SFAS 143 or SOP 96-1 have been met. Such costs are adjusted as additional information develops or circumstances change. Certain environmental costs receive regulatory accounting treatment, under which the costs are recorded as regulatory assets. Recoveries of environmental remediation costs from other parties are recognized when their receipt is deemed probable. Environmental expenditures that have future economic benefits are capitalized in accordance with our asset capitalization policy.

Note 13, Commitments and Contingencies of the 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 11, Retirement Plan and Post-Retirement Benefits of the Notes to Financial Statements, SPR maintains a qualified pension plan, a non-qualified supplemental executive retirement plan (SERP) and restoration plan, as well as a postretirement benefit (OPEB) plan which provides health and life insurance for retired employees. All employees are eligible for these benefits if they terminate with certain age and service requirements from the qualified and restoration plans, or if they reach retirement age and meet certain service requirements under the SERP and OPEB plans 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 are ultimately collected in rates billed to customers. Amounts are funded to trusts maintained for the plans. The amounts funded are then used to meet benefit payments to plan participants. SPR contributed $59.9 million (including contributions to SERP) and $17.3 million to its pension plan, in 2007 and 2006, respectively, and $46.1 million and $8.6 million to the other postretirement benefits plan in 2007 and 2006, respectively. At the present time it is not expected that any additional funding for the pension plan will be required for plan years 2007 or 2008 to meet the minimum funding levels defined by ERISA. SPR's funding requirements may change subject to market conditions. SPR uses a September 30 measurement date for its benefit plans.

*Pension Plans*

SPR's reported costs of providing non-contributory defined pension benefits (described in Note 11, Retirement Plan and Post-Retirement Benefits of the Notes to Financial Statements) are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience.

For example, pension costs are impacted by actual employee demographics (including age and employment periods), the level of contributions SPR makes to the plan, and earnings on plan assets. Changes made to the provisions of the plan may also impact current and future pension costs. Pension costs may also be significantly affected by changes in key actuarial assumptions, including anticipated rates of return on plan assets, the discount rates and demographic (mortality, retirement, termination) assumptions 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. SPR adopted SFAS 158 in 2006, which requires the immediate recognition of changes in benefit obligations due to differences between actuarial assumptions and actual experience in Accumulated Other Comprehensive Income, net of taxes. However, since SPR recovers SFAS 87 and SFAS 106 costs through rates, these amounts will be recorded as Other Regulatory Assets under the provisions of SFAS 71, and will be recognized as expense over a period of time. For the year ended December 31, 2007, 2006, and 2005, SPR recorded pension expense for all pension plans of approximately $29.3 million, $30.6 million, and $23.5 million, respectively, in accordance with the provisions of SFAS No. 87. Actual payments of benefits made to retirees and terminated vested employees for the year ended September 30, 2007, 2006 and 2005 were $31.9 million, $21 million and $20.3 million respectively.

SPR has not made changes to pension plan provisions in 2007, 2006, and 2005 that had significant impacts on recorded pension expense for these years. As further described in Note 11, Retirement Plan and Post-Retirement Benefits of the Notes to Financial Statements, SPR increased the discount rate used in determining pension expense from 6.00% in 2007 to 6.30% for the calendar year 2008. In November 2007 the Board approved a change in the defined benefit pension plan for its management, professional, administrative and technical employees from a final average pay formula to a cash balance formula. Employees with combined age and service totaling 75 years or more have the choice of staying with the current plan or electing to switch to the new plan. They have until March 31, 2008 to make this election. The new plan will go into effect on April 1, 2008. This change is expected to reduce pension expense and the benefit obligation, but its impact is not known at this time.

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

The following chart reflects the sensitivities associated with a change in certain actuarial assumptions by the indicated percentage for all pension plans. 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 and the reported annual pension cost (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 (dollars in millions, except percentages):

| Actuarial Assumption (dollars in millions) | Change in Assumption Incr/(Decr) | Impact on PBO Incr/(Decr) | Impact on PC Incr/(Decr) |
|---|---|---|---|
| Discount Rate | 1% | $ (85.5) | $ (10.3) |
| Rate of Return on Plan Assets | 1% | N/A | $ (5.2) |

In selecting an assumed discount rate for fiscal years 2007 and 2006 disclosures, and for fiscal years 2007 and 2006 pension cost, SPR's projected benefit payments were matched to the yield curve derived from a portfolio of over 500 high quality Aa bonds with yields within the 40th to 90th percentiles of these bond yields.

In selecting an assumed rate of return on plan assets, SPR considers past performance and economic forecasts for the types of investments held by the plan. Investment returns on plan assets in the retirement plan gained approximately $73.5 million in 2007 and $34.4 million in 2006. These returns, in conjunction with SPR's contributions, have improved the funded status compared to prior years.

*Other Postretirement Benefits*

SPR's reported costs of providing other postretirement benefits (described in Note 11, Retirement Plan and Post-Retirement Benefits of the Notes to Financial Statements) are dependent upon numerous factors resulting from actual plan experience and assumptions of future experience.

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

discount rates and demographic (mortality, retirement, termination) assumptions used in determining the postretirement benefit obligation and postretirement costs.

For the year ended December 31, 2007, 2006 and 2005, SPR recorded other postretirement benefit expense of approximately $11.3 million, $14.9 million, and $14.1 million, respectively, in accordance with the provisions of SFAS No. 106. Actual payments of benefits made to retirees for the year ended September 30, 2007, 2006 and 2005 were $10.0 million, $12.0 million, and $8.1 million respectively.

In 2007, SPR completed negotiations with SPPC's bargaining unit 1245 employees, and reached a settlement with regard to postretirement medical coverage. This agreement resulted in changes to SPR's future obligations under this plan, and as a result of a re-measurement of the plan obligation, SPR's 2007 expense was reduced by $1.3 million. There were no changes made to other postretirement benefit plan provisions in 2006 and 2005 which had any significant impact on recorded benefit plan amounts in those years. As further described in Note 11, Retirement Plan and Post-Retirement Benefits of the Notes to Financial Statements, SPR has revised the discount rate for its 2007 disclosures to 6.30%, as compared to 2006 disclosures of 6.00%. For determining the expense to be recorded in 2008, SPR moved to a 6.30% discount rate from 6.00% in 2007. In determining the other postretirement benefit obligation and related cost, these assumptions can change from period to period, and such changes could result in material changes to such amounts.

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

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

| Actuarial Assumption | Change in Assumption Incr/(Decr) | Impact on APBO Incr/(Decr) | Impact on PBC Incr/(Decr) |
|---|---|---|---|
| Discount Rate | 1% | $ (15.0) | $ (3.4) |
| Health Care Cost Trend Rate | 1% | $ 9.9 | $ 2.9 |
| Rate of Return on Plan Assets | 1% | N/A | $ (0.6) |

In selecting an assumed discount rate for fiscal year 2007 other postretirement benefits cost and disclosures, SPR's projected benefit payments were matched to the yield curve derived from a portfolio of over 500 high quality Aa bonds with yields within the 40th to 90th percentiles of these bond yields.

In selecting an assumed rate of return on plan assets, SPR considers past performance and economic forecasts for the types of investments held by the plan. Investment returns on plan assets gained $7.6 million in 2007 and $8 million in 2006.

**Unbilled Receivables**

Revenues related to the sale of energy are recorded based on meter reads, which occur on a systematic basis throughout a month, rather than when the service is rendered or energy is delivered. At the end of each month, the energy delivered to the customers from the date of their last meter read to the end of the month is estimated and the corresponding unbilled revenues are calculated. These estimates of unbilled sales and revenues are based on the ratio of billable days versus unbilled days, amount of energy procured and generated during that month, historical customer class usage patterns and the Utilities' current tariffs. Customer accounts receivable as of December 31, 2007, include unbilled receivables of $106 million and $79 million for NPC and SPPC, respectively. Customer accounts receivable as of December 31, 2006 include unbilled receivables of $92 million and $83 million for NPC and SPPC, respectively.

## RECENT PRONOUNCEMENTS

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

## 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 $42.5 million, $51.4 million, and $74.3 million of long-term debt interest costs for the years ended December 31, 2007, 2006 and 2005, respectively. The decrease in interest costs for the year ended December 31, 2007 as compared to the same period in 2006 was primarily due to lower interest costs and amortization costs related to debt redemptions in 2006. See Note 6, Long-Term Debt of the Notes to Financial Statements, for further discussion of the debt repurchase. The decrease in interest costs for the year ended December 31, 2006 as compared to the same period in 2005 was primarily due to the conversion of SPR's $300 million 7.25% Convertible Notes due 2010, the repurchase of the 7.93% Senior Notes associated with the PIES, and the reduced interest rate of 7.803% on the Senior Notes associated with the New PIES. See Note 14, Common Stock and Other Paid-in Capital of the Notes to Financial Statements, for further discussion on the PIES and Convertible Notes. The Holding Company's operating results for 2005 were negatively affected by early conversion fees of the Convertible Notes of approximately $35 million after taxes and unamortized debt issuance costs and legal fees associated with the Convertible Notes of approximately $4.7 million after taxes.

#### Other Subsidiaries

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

### *Sierra Pacific Resources (Consolidated)*

See Executive Overview, Overview of Major Factors Affecting Results of Operations for SPR Consolidated.

## ANALYSIS OF CASH FLOWS

SPR's consolidated net cash flows increased during the year ended December 31, 2007 compared to the same period in 2006 due to increases in cash from operating and financing activities offset by an increase in cash used by investing activities.

***Cash From Operating Activities.*** Cash flows from operating activities increased during the year ended December 31, 2007 compared to the same period in 2006 primarily due to NPC's increased operating income (excluding Reinstated Deferred Energy). NPC's operating income (excluding Reinstated Deferred Energy) increased primarily as a result of increases in rates due to NPC's GRC, the Western Energy Crisis Rate Case and the 2001 Deferred Energy Case, as discussed in Note 3, Regulatory Actions of the Notes to Financial Statements.

Other factors contributing to the increase in cash flows were:

- a decrease in payments made to suppliers;
- the timing of payments;
- improved credit terms with vendors;
- a BTER rate which better reflects actual fuel and purchased power costs;
- a decrease in interest expense paid; and
- the net settlement with Enron in 2006.

This was partially offset by an increase in payments for Pension and Other Post Retirement Benefits of $100 million.

***Cash Used By Investing Activities.*** Cash used by investing activities increased for the year ended December 31, 2007 compared to the same period in 2006 primarily due to expenditures for the Clark Peaking Units, the expansion of the Tracy Generating Station, the Ely Energy Center and utility infrastructure to support growth.

***Cash From Financing Activities.*** Cash from financing activities increased during the year ended December 31, 2007 compared to the same period in 2006 primarily due to a reduction in the redemption of debt and preferred stock by the Utilities. This increase was partially offset by a decrease in the sale of common stock and the restoration of dividend payments by SPR in 2007 of approximately $35.4 million.

SPR's consolidated net cash flows increased for the year ended December 31, 2006 compared to the same period in 2005, due to increases in cash from operating and financing activities, offset by cash used in investing activities. Cash from operating activities increased during 2006 when compared to 2005 due to increases in deferred energy and general rates and a decrease in

accounts receivable offset partially by the settlement with Enron. The increase was also offset by a reduction in accounts payable primarily associated with purchased power suppliers. Cash from financing activities increased primarily due to the issuance of 20 million shares of common stock in 2006. SPR received net proceeds of approximately $281 million for the issuance. Cash from financing activities also increased during the year ended December 31, 2006 as compared to the same period in 2005 primarily as a result in increased debt offerings partially offset by redemption of debt and preferred stock. Cash used by investing activities for the year ended December 31, 2006 increased significantly when compared to the same period in 2005 primarily due to the acquisition of Silverhawk by NPC and the expansion of the Tracy Generating Station by SPPC. This increase was offset by the sale of the investment in Tuscarora for approximately $100 million and a reduction in construction at Lenzie that was placed in service in 2006.

## LIQUIDITY AND CAPITAL RESOURCES (SPR CONSOLIDATED)

### Overall Liquidity

SPR's consolidated operating cash flows are primarily derived from the operations of NPC and SPPC. The primary source of operating cash flows for the Utilities is revenues (including the recovery of previously deferred energy costs and natural gas costs) from sales of electricity and natural gas. Significant uses of cash flows from operations include the purchase of electricity and natural gas, other operating expenses, capital expenditures and interest. Operating cash flows can be significantly influenced by factors such as weather, regulatory outcomes, and economic conditions.

Available Liquidity as of December 31, 2007 (in millions)

| | SPR | NPC | SPPC |
|---|---|---|---|
| Cash and Cash Equivalents | $ 68.0 | $ 37.0 | $ 23.8 |
| Balance available on Revolving Credit Facility | N/A | 595.1 | 329.5 |
| | $ 68.0 | $ 632.1 | $ 353.3 |

In addition to cash on hand and the Utilities' revolving credit facilities, the Utilities may issue debt up to $1.1 billion on a consolidated basis, subject to certain limitations discussed below and in the Utilities' respective sections, to meet its financial obligations.

SPR and the Utilities anticipate that they will be able to meet short-term operating costs, such as fuel and purchased power costs, with internally generated funds, including the recovery of deferred energy, and the use of their revolving credit facilities. To manage liquidity needs as a result of seasonal peaks in fuel requirement, SPR and the Utilities may use hedging activities. However, to fund long-term capital requirements, SPR and the Utilities may meet such financial obligations with a combination of internally generated funds, the use of the Utilities' revolving credit facilities and the issuance of long-term debt, preferred securities, and/or capital contributions from SPR.

Continued improvement in the credit ratings of SPR and the Utilities in 2007 (see Credit Ratings below) has strengthened the liquidity position of the Utilities by allowing for the resumption of normal payment terms with our counterparties and the elimination of cash collateral requirements. Existing collateral requirements with counterparties have been satisfied with letters of credit. The recent credit rating upgrades will likely reduce the cost of borrowing under the Utilities' revolving credit facilities. In addition, the upgrades have the potential to provide SPR and the Utilities better access to capital markets and to reduce the cost of issuing additional long-term debt. However, disruptions in the banking and capital markets not specifically related to SPR or the Utilities may affect their ability to access funding sources or cause an increase in the return required by investors.

SPR has approximately $40.7 million payable of debt service obligations for 2008, which it intends to pay through dividends from subsidiaries. (See "Factors Affecting Liquidity-Dividends from Subsidiaries" below)

SPR designs operating and capital budgets to control operating costs and capital expenditures. In addition to operating expenses, SPR has continuing commitments for capital expenditures for construction, improvement and maintenance of facilities.

Detailed below are SPR's Capital Structure, Capital Requirements, recently completed stock and financing transactions and factors affecting our ability to obtain debt on favorable terms, including the effect of our holding company structure and limitation on dividends from the Utilities.

## Capital Structure (SPR Consolidated)

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

| | 2007 | | 2006 | |
|---|---|---|---|---|
| Current Maturities of Long-Term Debt | $ 110,285 | 1.5% | $ 8,348 | 0.1% |
| Long-Term Debt | 4,137,864 | 57.1% | 4,001,542 | 60.3% |
| Common Equity | 2,996,575 | 41.4% | 2,622,297 | 39.6% |
| Total | $ 7,244,724 | 100.0% | $ 6,632,187 | 100.0% |

## Capital Requirements

*Construction Expenditures*

SPR's annual consolidated cash construction expenditures have increased since 2003 and are expected to continue to increase due to programs designed to meet electric load growth and reliability needs. Cash construction expenditures for the years ended 2007, 2006 and 2005 were approximately $1.1 billion, $912 million and $591 million, respectively. SPR's consolidated cash requirements for construction expenditures for 2008 are projected to be $1.2 billion. SPR's consolidated cash requirements for cash construction expenditures for 2008-2012 are projected to be $7.6 billion. To fund these capital projects SPR and the Utilities may meet such financial obligations with a combination of internally generated funds, the use of the Utilities' revolving credit facilities, the issuance of long-term debt, and if necessary, the issuance of equity by SPR.

*Contractual Obligations (SPR Consolidated)*

The table below provides SPR's contractual obligations on a consolidated basis (except as otherwise indicated) 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. Certain contracts contain variable factors which required SPR to estimate the obligation depending on the final variable amount. Actual amounts could differ. The table does not include estimated construction expenditures described above, except for major capital projects for which the Utilities have executed contracts by December 31, 2007, or Pension funding requirements as discussed in Note 11, Retirement Plan and Post-Retirement Benefits of the Notes to Financial Statements, as of December 31, 2007 (dollars in thousands):

| | Payment Due by Period | | | | | | |
|---|---|---|---|---|---|---|---|
| | 2008 | 2009 | 2010 | 2011 | 2012 | Thereafter | Total |
| NPC/SPPC Long-Term Debt Maturities | $ 101,655 | $ 15,600 | $ - | $ 364,000 | $ 230,000 | $ 2,952,329 | $ 3,663,584 |
| NPC/SPPC Long-Term Debt Interest Payments | 230,973 | 227,285 | 226,685 | 209,655 | 186,655 | 2,755,738 | 3,836,991 |
| SPR Long-Term Debt Maturities | - | - | - | - | 63,670 | 460,539 | 524,209 |
| SPR Long-Term Debt Interest Payments | 40,743 | 40,743 | 40,743 | 40,743 | 38,052 | 91,774 | 292,798 |
| Other Long-Term Liabilities FIN 48[1] | 457 | - | - | - | - | - | 457 |
| Purchased Power | 501,750 | 409,991 | 505,580 | 563,412 | 598,530 | 8,640,656 | 11,219,919 |
| Coal and Natural Gas | 459,479 | 144,953 | 110,162 | 101,770 | 72,836 | 451,776 | 1,340,976 |
| Long-Term Service Agreements[2] | 20,250 | 22,469 | 22,469 | 22,469 | 22,469 | 175,377 | 285,503 |
| Capital Projects[3] | 196,593 | 72,425 | 2,873 | - | - | - | 271,891 |
| Operating Leases | 23,063 | 21,235 | 19,629 | 9,356 | 5,699 | 71,413 | 150,395 |
| Capital Leases | 7,158 | 7,218 | 8,004 | 5,924 | 6,449 | 26,671 | 61,424 |
| Total Contractual Cash Obligations | $ 1,582,121 | $961,919 | $ 936,145 | $1,317,329 | $1,224,360 | $ 15,626,273 | $21,648,147 |

(1) At December 31, 2007, SPR has recorded a $25.0 million liability in accordance with FIN 48, of which $24.6 million is classified as non-current. SPR is unable to make a reasonably reliable estimate of the period of cash payments to relevant tax authorities; consequently, only the current liability of $457 thousand is included in the contractual obligations table above.

(2) Includes long term service agreements for the Chuck Lenzie Generation Station, Silverhawk Facility, and Tracy Combined Cycle Plant.

(3) Capital Projects include the tenant improvement project for the Southern Operations Center, Harry Allen Combined Cycle Project, Clark Peaking Unit Turbine agreement, Clark Peaking Units EPC agreement, Clark 5-8 Dry Low Nox Burner Project, and Tracy Combined Cycle EPC agreement.

*Pension Plan Matters*

SPR has a qualified pension plan that covers substantially all employees of SPR, NPC and SPPC. The annual net benefit cost for the plan is expected to decrease in 2008 to $25.1 million compared to the 2007 cost of $29.3 million. As of September 30, 2007, the measurement date, the plan was under funded on a FAS 158 pension benefit obligation basis. Refer to Note 11, Retirement Plan and Post-Retirement Benefits, of the Notes to Financial Statements. During 2007, SPR contributed a total of $54 million to meet its funding obligations under the plan. At the present time it is not expected that any additional funding will be required in 2008 to meet the minimum funding level requirements defined by the Pension Benefit Guaranty Corporation and ERISA.

**Capital Stock Transaction (SPR-Holding Company)**

In December 2007, SPR issued 12 million shares of its $1 par value common stock. Net proceeds from the issuance were $202.8 million. In December 2007, SPR contributed capital to NPC of approximately $65 million, and to SPPC of approximately $65 million. Both Utilities used the proceeds to repay indebtedness under their revolving credit facilities, and for general corporate purposes. Additionally, SPR contributed $53 million and $20 million to NPC and SPPC, respectively, in January 2008.

**Financing Transactions (SPR-Holding Company)**

*Debt Repurchase*

In December 2007, SPR repurchased approximately $10.5 million of the 7.803% Senior Notes and approximately $14.5 million of the 6.75% Senior Notes. SPR used cash on hand to pay the total consideration of approximately $26 million, which included a premium and accrued interest. As of December 31, 2007, the outstanding balances for the 7.803% Senior Notes and 6.75% Senior Notes were $63.7 million and $210.5 million, respectively.

**Factors Affecting Liquidity**

*Effect of Holding Company Structure*

As of December 31, 2007, SPR (on a stand-alone basis) has outstanding debt and other obligations including, but not limited to: $63.7 million of its unsecured 7.803% Senior Notes due 2012; $210.5 million of its unsecured 6.75% Senior Notes due 2017; and $250 million of its unsecured 8.625% Senior Notes due 2014.

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

As of December 31, 2007, SPR, NPC, SPPC and their subsidiaries had approximately $4.2 billion of debt and other obligations outstanding, consisting of approximately $2.5 billion of debt at NPC, approximately $1.2 billion of debt at SPPC and approximately $524 million of debt at the holding company and other subsidiaries. Although SPR and the Utilities are parties to agreements that limit the amount of additional indebtedness they may incur, SPR and the Utilities retain the ability to incur substantial additional indebtedness and other liabilities.

*Dividends from Subsidiaries*

Since SPR is a holding company, substantially all of its cash flow is provided by dividends paid to SPR by NPC and SPPC on their common stock, all of which is owned by SPR. Since NPC and SPPC are public utilities, they are subject to regulation by state utility commissions, which impose limits on investment returns or otherwise impact the amount of dividends that the Utilities may declare and pay.

In addition, certain agreements entered into by the Utilities set restrictions on the amount of dividends they may declare and pay and restrict the circumstances under which such dividends may be declared and paid. In addition to the restrictions imposed by specific agreements, the Federal Power Act prohibits the payment of dividends from "capital accounts." 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.

As of December 31, 2007, NPC and SPPC were able to pay dividends of $757.0 million and $223.5 million, respectively, under the most restrictive test in its financing agreements. Management does not believe the total amount of dividends that the Utilities can pay to SPR under their financing agreements is significantly restrictive. In 2007, NPC paid $28.2 million in dividends to

SPR and approximately $10.8 million, declared in November 2007, was outstanding as of December 31, 2007. In 2007 SPPC paid $14.2 million in dividends to SPR and approximately $5.3 million, declared in November 2007, was outstanding as of December 31, 2007. In January 2008, NPC and SPPC paid the outstanding dividends of $10.8 million and $5.3 million, respectively. On February 7, 2008, NPC and SPPC declared dividends to SPR of approximately $14.0 million and $8.0 million, respectively.

*Credit Ratings*

SPR, NPC and SPPC are rated by four Nationally Recognized Statistical Rating Organizations (NRSRO's): Dominion Bond Rating Service (DBRS), Fitch Ratings Ltd. (Fitch), Moody's Investors Service, Inc. (Moody's) and Standard & Poor's (S&P). As of February 22, 2008**,** the ratings are as follows:

| | | Rating Agency | | | |
|---|---|---|---|---|---|
| | | DBRS | Fitch | Moody's | S&P |
| SPR | Sr. Unsecured Debt | BB (low) | BB- | Ba3 | B |
| NPC | Sr. Secured Debt | BBB (low)* | BBB-* | Baa3* | BB+ |
| NPC | Sr. Unsecured Debt | Not rated | BB | Not rated | B |
| SPPC | Sr. Secured Debt | BBB (low)* | BBB-* | Baa3* | BB+ |

* Ratings are investment grade

Three of the four rating agencies currently rate the Utilities' senior secured debt investment grade. Moody's and DBRS's rating outlook for SPR, NPC and SPPC is Stable. In June 2007, S&P and Fitch revised their outlook on all three companies to Positive from Stable.

A security rating is not a recommendation to buy, sell or hold securities. Security ratings are subject to revision and withdrawal at any time by the assigning rating organization, and each rating should be evaluated independently of any other rating.

*Credit Ratings of Bond Insurers*

Recent sub-prime mortgage issues have adversely affected the overall financial markets, generally resulting in increased interest rates, reduced access to the capital markets, and actual or potential downgrades of bond insurers, among other negative matters. The interest rates on certain issues of the Utilities, Variable Rate Notes of approximately $556 million, as presented in our Consolidated Statements of Capitalization are periodically reset through auction processes. These securities are supported by bond insurance policies provided by either Ambac, FGIC, or MBIA (collectively, the "Insurers"), and the interest rates on those securities are directly affected by the rating of the bond insurer due to, among other things, the impact that such ratings have on the success or failure of the auction process. The uncertainty with the Insurers' credit quality has had an impact on the Utilities' interest costs for these specific securities in the fourth quarter of 2007, although not significant. However, if the credit quality of the Insurers continues to deteriorate, the Utilities' could experience higher interest costs for these securities.

*Energy Supplier Matters*

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.

Under these contracts, a material adverse change in NPC and SPPC would allow the counterparty to request adequate financial assurance, which, if not provided within three business days, could cause a default. A default must be declared within 30 days of the event, giving rise to the default becoming known. A default will result in a termination payment equal to the present value of the net gains and losses for the entire remaining term of all contracts between the parties aggregated to a single liquidated amount due within three business days following the date the notice of termination is received. The mark-to-market value, which is substantially based on quoted market prices, can be used to roughly approximate the termination payment and benefit at any point in time. The net mark-to-market value as of December 31, 2007 for all suppliers continuing to provide power under a WSPP agreement would approximate a $10.4 million payment by NPC and an approximate $1.1 million payment by SPPC. These contracts qualify for the normal purchases scope exception of SFAS No. 133, and as such, are not required to be mark-to-market on the balance sheet. Refer to Note 9, Derivatives and Hedging Activities, of the Notes to Financial Statements for further discussion.

*Gas Supplier Matters*

With respect to the purchase and sale of natural gas, NPC and SPPC use several types of standard industry contracts. The natural gas contract terms and conditions are more varied than the electric contracts. Consequently, some of the contracts contain language similar to that found in the WSPP agreement and other agreements have unique provisions dealing with material adverse changes. Because of creditworthiness concerns, most contracts and confirmations for natural gas purchases have been modified or

separate agreements have been made to either shorten the normal payment due date or require payment in advance of delivery. At the present time, no counter-parties require payment in advance of delivery.

Gas transmission service is secured under FERC Tariffs or custom agreements. These service contracts and Tariffs require the user to 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.

*Financial Covenants*

*Nevada Power Company and Sierra Pacific Power Company*

Each of NPC's $600 million Second Amended and Restated Revolving Credit Agreement and SPPC's $350 million Amended and Restated Revolving Credit Agreement, dated November 2005, and amended in April 2006, contains two financial maintenance covenants. The first requires that the Utility maintain a ratio of consolidated indebtedness to consolidated capital, determined as of the last day of each fiscal quarter, not to exceed 0.68 to 1. The second requires that the Utility maintain a ratio of consolidated cash flow to consolidated interest expense, determined as of the last day of each fiscal quarter for the period of four consecutive fiscal quarters, not to be less than 2.0 to 1. As of December 31, 2007, both Utilities were in compliance with these covenants.

***Ability to Issue Debt***

*Sierra Pacific Resources*

Certain debt of SPR places restrictions on debt incurrence, liens and dividends, unless, at the time the debt is incurred, the ratio of consolidated cash flow to fixed charges for SPR's most recently ended four quarter period on a pro forma basis is at least 2 to 1. Under this covenant restriction, as of December 31, 2007, SPR would be allowed to incur up to $1.1 billion of additional indebtedness on a consolidated basis.

Notwithstanding this restriction, under the terms of the debt, SPR would still be permitted to incur debt including, but not limited to, obligations incurred to finance property construction or improvement, certain intercompany indebtedness, or indebtedness incurred to finance capital expenditures, pursuant to the two Utilities' integrated resource plans. NPC and SPPC would also be permitted to incur a combined total of up to $500 million in indebtedness and letters of credit under their respective revolving credit facilities.

If the applicable series of debt is 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 remain investment grade by both Moody's and S&P (see Credit Ratings above).

*Nevada Power Company*

*Ability to Issue Debt*

Certain factors impact NPC's ability to issue debt:

1. Financing Authority from the PUCN: On June 22, 2007, NPC received PUCN authorization to enter into financings of $3.91 billion through 2009. Of this total, $1.35 billion is contingent upon the PUCN's approval of the Ely Energy Center in 2008. The remaining authority, $2.56 billion, includes authority for the revolving credit facility, and authority to issue new debt and to refinance existing debt. As of December 31, 2007, NPC had used $600 million of the $2.56 billion authority for the revolving credit facility, and $350 million for the issuance of the 6.75% General and Refunding Mortgage Notes, Series R. As a result, approximately $1.6 billion of the authority remains.

2. Financial Covenants in its and SPR's financing agreements. The terms of certain SPR debt prohibit NPC and SPPC from incurring additional indebtedness unless certain conditions have been met. See SPR's Ability to Issue Debt. In addition to the SPR debt, the terms of NPC's Series G, I and L General and Refunding Mortgage Notes which mature in 2013, 2012, and 2015, respectively, collectively (NPC's Debt) restrict NPC from incurring any additional indebtedness unless certain covenants are satisfied. However, as of December 31, 2007, the financial covenants under NPC's Debt allow for greater borrowings than SPR's cap on additional indebtedness; therefore, NPC is limited by SPR's cap on additional consolidated indebtedness of $1.1 billion. If NPC's Series G, I or L General and Refunding Mortgage Notes are upgraded to investment grade by S&P, the restrictions imposed by those Notes will be suspended and will no longer be in effect so long as the applicable series of securities remain investment grade by both Moody's and S&P.

Since SPR's debt covenant limitations are calculated on a consolidated basis, SPR's debt covenant limitations may allow for higher or lower borrowing than $1.1 billion, depending on the Utilities' combined outstanding balances under their revolving credit facilities at the time of the covenant calculations.

*Ability to Issue General and Refunding Mortgage Securities*

To the extent that NPC has the ability to issue debt under the most restrictive covenants in its financing agreements and has financing authority to do so from the PUCN, NPC's ability to issue secured debt is still limited by the amount of bondable property or retired bonds that can be used to issue debt under NPC's General and Refunding Mortgage Indenture ("Indenture").

The Indenture creates a lien on substantially all of NPC's properties in Nevada. As of December 31, 2007, $2.8 billion of NPC's General and Refunding Mortgage Securities were outstanding. NPC had the capacity to issue $758 million of General and Refunding Mortgage Securities as of December 31, 2007. That amount is determined on the basis of:

1. 70% of net utility property additions;
2. the principal amount of retired General and Refunding Mortgage Securities; and/or
3. the principal amount of first mortgage bonds retired after October 2001.

Property Additions include plant in service and specific assets in construction work in progress. The amount of bond capacity listed above does not include eligible property in construction work in progress.

NPC also has the ability to release property from the lien of the mortgage indenture 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.

*Sierra Pacific Power Company*

*Ability to Issue Debt*

Certain factors impact SPPC's ability to issue debt:

1. Financing Authority from the PUCN: On June 22, 2007, SPPC received PUCN authorization to enter into financings of $1.72 billion through 2009. Of this total, $300 million is contingent upon the PUCN's approval of the Ely Energy Center in 2008. The remaining authority, $1.42 billion, includes authority for the revolving credit facility, and authority to issue new debt and to refinance existing debt. As of December 31, 2007, SPPC had used $350 million of the $1.42 billion authority for the revolving credit facility, and $325 million for the issuance of the 6.75% General and Refunding Notes, Series P. As such, approximately $745 million of the authority remains.

2. Financial Covenants in its and SPR's financing agreements. The terms of certain SPR debt prohibit NPC and SPPC from incurring additional indebtedness unless certain conditions have been met. See SPR's Ability to Issue Debt. In addition to the SPR debt, the terms of SPPC's Series H General and Refunding Mortgage Notes, which mature in 2012, (collectively "SPPC's Debt") restrict SPPC from incurring any additional indebtedness unless certain covenants are satisfied. However, as of December 31, 2007, the financial covenants under SPPC's debt allow for greater borrowings than SPR's cap on additional indebtedness; therefore, SPPC is limited by SPR's cap on additional consolidated indebtedness of $1.1 billion. If SPPC's Series H General and Refunding Mortgage Notes are upgraded to investment grade by S&P, the restrictions imposed by those Notes will be suspended and will no longer be in effect so long as the applicable series of securities remain investment grade by both Moody's and S&P.

Since SPR's debt covenant limitations are calculated on a consolidated basis, SPR's debt covenant limitations may allow for higher or lower borrowing than $1.1 billion, depending on the Utilities' combined outstanding balances under their revolving credit facilities at the time of the covenant calculations.

*Ability to Issue General and Refunding Mortgage Securities*

To the extent that SPPC has the ability to issue debt under the most restrictive covenants in its financing agreements and has financing authority to do so from the PUCN, SPPC's ability to issue secured debt is still limited by the amount of bondable property or retired bonds that can be used to issue debt under SPPC's General and Refunding Mortgage Indenture (Indenture).

The Indenture creates a lien on substantially all of SPPC's properties in Nevada and California. As of December 31, 2007, $1.5 billion of SPPC's General and Refunding Mortgage Securities were outstanding. SPPC had the capacity to issue $348 million of General and Refunding Mortgage Securities as of December 31, 2007. That amount is determined on the basis of:

1. 70% of net utility property additions;
2. the principal amount of retired General and Refunding Mortgage Securities; and/or
3. the principal amount of first mortgage bonds retired after October 2001.

Property Additions include plant in service and specific assets in construction work in progress. The amount of bond capacity listed above does not include eligible property in construction work in progress.

*Cross Default Provisions*

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

## 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 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. Some 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 filed every three years, which has a twenty-year planning horizon;
(2) the Energy Supply Plan ("ESP"), which is an intermediate term resource procurement and risk management plan that establishes the supply portfolio strategies 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 ESP operates in conjunction with the PUCN-approved twenty-year IRP. It serves as a guide for near-term execution and fulfillment of energy needs. When the ESP calls for executing contracts with a duration of more than three years, the IRP regulations require PUCN approval as part of the resource planning process.

In developing and executing ESPs, management guidelines followed by the Utilities include:

- Maintaining an energy supply plan that balances the goals of minimizing costs, risks and price volatility (retail price stability), while maximizing reliability and predictability of supply;
- Investigating feasible commercial options to execute the ESP;
- Applying quantitative techniques and diligence commensurate with risk to evaluate and execute each transaction;
- Monitoring the portfolio against evolving market conditions and managing the resource optimization options; and
- Ensuring 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 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 thresholds 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 June 2006 and received approval in November 2006. SPPC's IRP was filed in June 2007 and received approval in December 2007. Between IRP filings, the Utilities are required to seek PUCN approval for modifications to their resource plans and for power purchases with terms of three years or greater by filing amendments to prior IRP filings.

The Utilities 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 update their intermediate term ESPs annually. In June 2007, SPPC filed a new 20-year IRP, which included an ESP for the years 2008-2010. In July 2007, NPC filed the Fourth Amendment to its 2006 IRP which included, among other things, an ESP update for the two remaining years of the planning cycle, 2008 and 2009. Both plans were approved by the EROC and the CEO prior to submission to the PUCN. The ESPs operate within the framework of the PUCN-approved 20-year IRPs. They serve as a guide for near-term execution and fulfillment of energy needs. When the ESPs call for the execution of contracts of duration of more than three years, an amendment to the IRP is prepared and submitted for PUCN approval. In December 2007, NPC filed the fifth amendment to the IRP agreement that requested PUCN approval of a ten-year tolling agreement for the purchase of 570 MW of capacity and energy. The fuel, power procurement and risk management strategies contained in the ESPs filed in 2007 were found to be reasonable and prudent by the PUCN in November 2007.

In 2008, NPC is anticipating the addition of the Clark Peaking units of 619 MWs and SPPC is anticipating the addition of 541 MWs at Tracy and a 203 MW purchase power contract with Newmont. For the remainder of their power needs, the PUCN approved ESPs provide for a competitive acquisition process to secure the required resources. Both Utilities have issued Requests for Proposals and executed forward contracts for their resource needs for the summer of 2008. The portfolio mix consists of owned generating resources, forward contracts for power and 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 purchased power cost and market price and supply 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 some counter-parties in weak financial conditions.
- Procure to match a difficult load profile, to the extent possible.
- Hedge the gas price risk exposure in the fuel portfolio through the purchase of a set of risk management options.
- Manage energy price risk through ongoing intermediate and short-term optimization activities (e.g., optimizing the dispatch of NPC generation and/or buying directly from the market).

Both of the ESPs reflect the Utilities' strategies, embedded in their filed IRPs, to minimize supply and price risk through acquisition or construction of company owned generating resources in the intermediate term (e.g., peaking capacity at Clark Generating Station; Tracy combined cycle addition), forward contracts to meet capacity needs in the shorter term, and pursuit of fuel diversity options such as coal and renewables in the longer term.

**Long Term Purchased Power Activities**

The Utilities update their long-term energy supply plans on an annual basis in concert with the preparation of their respective ESPs, which are described in the preceding section. As noted above, the ESPs serve as a guide for near-term execution and fulfillment of energy needs. When the energy supply plans call for contracts of duration more than three years, requests for proposals are issued, bids are evaluated, and contracts are executed with the successful bidders. Those contracts are submitted to the PUCN for approval through an amended IRP.

Currently, NPC has approximately 1,204 MW of long term contracts with various providers, terms and expiration dates. In addition, NPC has two pending contracts filed with the PUCN that if approved will provide NPC with 1,824 MW of long term contracts with various providers. SPPC currently has 286 MWs of long term contracts with various providers, terms and expirations dates.

Currently, NPC and SPPC obtain 90.6 MWs and 184.0 MWs, respectively of renewable energy and associated portfolio energy credits from solar, geothermal, hydroelectric, and biomass long term purchase power contracts with renewable providers. In addition, NPC and SPPC have contracts with similar renewable providers for 287.9 MWs and 27.4 MWs, respectively, which are currently under development.

**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 and operating reserve requirement. The Utilities commit and dispatch generating units based on the comparative economics of generation versus spot-market purchase opportunities. Any amount of excess capacity or energy is sold on the wholesale market, while any deficient capacity or energy position is filled by either buying on the spot market or utilizing available generating capacity.

The day-ahead resource optimization begins with an analysis of projected hourly loads, existing resources and operating reserve requirements. Firm forward take-or-pay contracts are scheduled and counted towards meeting the capacity needs of the day being pre-scheduled. The day-of resource optimization involves minimizing system production costs each hour by lowering or raising generating unit output or buying power and/or selling excess power in the wholesale market all in order to meet the system load requirement and operating reserve requirement. 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 available excess energy when it exists.

Real-time resource optimization requires an hourly determination of whether to increase or decrease the loading of on-line generating units, commit previously off-line generating units, un-commit on-line generating units, sell excess power, or purchase power in the real-time market to meet the companies' resource needs. In order to achieve the lowest production cost, the projected incremental or decremental cost of the next available generation resource options is compared to determine the lowest cost option.

The Utilities have developed a Portfolio Optimization Strategy, approved by the PUCN, to sell excess generating capacity during the shoulder months. The objective of the Portfolio Optimization Strategy is to reduce ratepayer costs by offsetting any profit from the sales of electricity against fuel and purchased power costs.

## NEVADA POWER COMPANY

## RESULTS OF OPERATIONS

NPC recognized net income of $165.7 million in 2007 compared to net income of $224.5 million in 2006 and $132.7 million in 2005. NPC's operating results for 2007 decreased over 2006 primarily as a result of the reinstatement of deferred energy of approximately $116.2 million net of taxes recorded in 2006. NPC's operating results for 2006 improved over 2005 primarily as a result of the reinstatement of deferred energy and the carrying charge associated with the Lenzie generating station, partially offset by increased interest expense.

In February 2008, NPC declared a dividend to SPR for approximately $14.0 million. In 2007, NPC paid $28.2 million in dividends to SPR and declared an additional $10.8 million dividend, which was subsequently paid in January 2008. In 2006, NPC

paid $35.8 million in dividends to SPR and declared an additional $13.5 million dividend. In 2005, NPC paid and declared common stock dividends of $35.3 million to SPR.

Gross margin is presented by NPC in order to provide information that management believes aids the reader in determining how profitable the electric business is at the most fundamental level. Gross margin, which is a "non-GAAP financial measure" as defined in accordance with SEC rules, provides a measure of income available to support the other operating expenses of the business and is a key factor utilized by management in its analysis of its business.

NPC believes presenting gross margin allows the reader to assess the impact of NPC's regulatory treatment and its overall regulatory environment on a consistent basis. Gross margin, as a percentage of revenue, is primarily impacted by the fluctuations in electric and natural gas supply costs versus the fixed rates collected from customers. While these fluctuating costs impact gross margin as a percentage of revenue, they only impact gross margin amounts if the costs cannot be passed through to customers. Gross margin, which NPC calculates as operating revenues less fuel and purchased power costs, provides a measure of income available to support the other operating expenses of NPC. Gross margin changes based on such factors as general base rate adjustments (which are required to be filed by statute every two years) and reflect NPC's strategy to increase internal power generation versus purchased power, which generates no gross margin.

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

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2007 | Change from Prior Year | 2006 | Change from Prior Year | 2005 |
| Operating Revenues: | | | | | |
| Electric | $ 2,356,620 | 10.9% | $ 2,124,081 | 12.8% | $ 1,883,267 |
| Energy Costs: | | | | | |
| Purchased power | 688,606 | -10.0% | 764,850 | -20.6% | 963,888 |
| Fuel for power generation | 594,382 | 7.5% | 552,959 | 99.6% | 277,083 |
| Deferral of energy costs-net | 233,166 | 152.6% | 92,322 | -302.2% | (45,668) |
| | $ 1,516,154 | 7.5% | $ 1,410,131 | 18.0% | $ 1,195,303 |
| Gross Margin before reinstatement of Deferred Energy Cost | $ 840,466 | 17.7% | $ 713,950 | 3.8% | $ 687,964 |
| Reinstatement of Deferred Energy Costs[1] | $ - | N/A | $ 178,825 | N/A | $ - |
| Gross Margin after reinstatement of Deferred Energy Costs | $ 840,466 | -5.9% | $ 892,775 | 29.8% | $ 687,964 |

[1]Gross Margin for the year ended December 31, 2006 increased significantly from prior periods primarily due to the reinstatement of deferred energy costs as discussed further in Note 3. Regulatory Actions of the Notes to Financial Statements.

NPC's gross margin before reinstatement of deferred energy cost increased for the year ended 2007 compared to the same period in 2006 primarily due to an increase in Base Tariff General Rates (BTGR) as a result of NPC's 2006 GRC, effective June 1, 2007, which increased general rates $120 million, a 5.66% increase. Also contributing to the increase was customer growth.

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

| | 2007 | | 2006 | | 2005 |
|---|---|---|---|---|---|
| | Amount | Change from Prior year | Amount | Change from Prior year | Amount |
| **Electric Operating Revenues:** | | | | | |
| Residential | $ 1,102,418 | 13.0% | $ 975,568 | 18.5% | $ 823,095 |
| Commercial | 480,613 | 8.6% | 442,477 | 12.0% | 395,016 |
| Industrial | 684,221 | 8.3% | 631,762 | 12.8% | 560,059 |
| Retail Revenues | 2,267,252 | 10.6% | 2,049,807 | 15.3% | 1,778,170 |
| Other [1] | 89,368 | 20.3% | 74,274 | -29.3% | 105,097 |
| **Total Revenues** | $ 2,356,620 | 10.9% | $ 2,124,081 | 12.8% | $ 1,883,267 |
| Retail sales in thousands of megawatt-hours (MWh) | 21,621 | 3.8% | 20,820 | 7.0% | 19,455 |
| Average retail revenue per MWh | $ 104.86 | 6.5% | $ 98.45 | 7.7% | $ 91.40 |

[1] Primarily wholesale, as discussed below

NPC's retail revenues increased in 2007 compared to 2006 due to increases in retail rates, customer growth and hotter summer weather. Retail rates increased as a result of NPC's various Base Tariff Energy Rate (BTER) and Deferred Energy Cases and NPC 2006 GRC, effective June 1, 2007 (see Note 3, Regulatory Actions of the Notes to Financial Statements). Residential, commercial and industrial customers increased by 2.7%, 4.6% and 4.6%, respectively.

NPC's retail revenues increased in 2006 compared to 2005 due to increases in retail rates, customer growth and weather. Retail rates increased as a result of NPC's various Base Tariff Energy Rate (BTER) and deferred energy cases (see Note 3, Regulatory Actions of the Notes to Financial Statements). Residential, commercial and industrial customers increased by 4.9%, 5.1% and 4.3%, respectively. Customer usage increased due to colder winter weather and hotter spring weather.

Electric Operating Revenues – Other increased in 2007 compared to 2006, primarily due to a decrease in the reclassification of revenues in 2007 associated with Mohave which have been reclassified to Other Regulatory Assets as a result of the shut down of the Mohave Generating Station. For further discussion on Mohave refer to Note 1, Summary of Significant Accounting Policies in the Notes to Financial Statements. This increase was partially offset by a decrease in energy usage by Public Authority customers due to their transitioning to distribution only services by purchasing their energy from other sources, as allowed by Nevada law under certain circumstances.

Electric Operating Revenues – Other decreased in 2006 compared to 2005, primarily due to revenues associated with Mohave which have been reclassified to Other Regulatory Assets as a result of the shut down of the Mohave Generating Station. For further discussion on Mohave refer to Note 1, Summary of Significant Accounting Policies in the Notes to Financial Statements. Also contributing to the decrease was a decrease in transmission revenues as a result of the purchase of Silverhawk. In 2005, the previous owner of Silverhawk used NPC's transmission system to distribute electricity from the facility.

## Energy Costs

Energy Costs include Purchased Power and Fuel for Generation. Energy costs are dependent upon several factors which may vary by season or period. As a result, NPC's usage and average cost per MWh of Purchased Power versus Fuel for Generation to meet demand can vary significantly. Factors that may affect Energy Costs include, but are not limited to:

- Weather
- Generation efficiency
- Plant outages
- Total system demand
- Resource constraints
- Transmission constraints
- Natural gas constraints,
- Long term contracts; and
- Mandated power purchases

| | 2007 | | 2006 | | 2005 |
|---|---|---|---|---|---|
| | Amount | Change from Prior Year | Amount | Change from Prior Year | Amount |
| Energy Costs | $1,282,988 | -2.6% | $1,317,809 | 6.2% | $1,240,971 |
| Total System Demand | 23,030 | 2.8% | 22,408 | 6.8% | 20,988 |
| Average cost per MWH | $55.71 | -5.3% | $58.81 | -0.5% | $59.13 |

Energy costs and the average cost per MWH decreased for the year ended December 31, 2007 as compared to 2006 primarily due to NPC's increased ability to generate its own power economically and a decrease in natural gas prices. The decrease in the average cost per MWh was partially offset by an increase in the average cost per MWh for purchased power due to hotter weather. NPC's generation capacity is not sufficient to meet total system demand, particularly during peak times, therefore it must purchase power which is on average typically more expensive than internal generation. Total system demand increased slightly as a result of hotter weather and customer growth.

Energy costs increased in 2006 compared to 2005, primarily due to an increase in total system demand as a result of customer growth and hotter weather, an increase in the cost of hedging instruments purchased when gas prices were escalating as a result of the 2005 hurricanes in the southern United States and the shutdown of Mohave which is a coal generating facility. These increases were partially offset by the increase in generation volume as a result of the addition of Lenzie Block 1 & 2, which were placed in service in February and May 2006, respectively, and Silverhawk which was placed in service in January 2006. These generating plants are highly efficient and more economical than purchasing power.

**Purchased Power**

| | 2007 | | 2006 | | 2005 |
|---|---|---|---|---|---|
| | Amount | Change from Prior Year | Amount | Change from Prior Year | Amount |
| **Purchased Power** | $ 688,606 | -10.0% | $ 764,850 | -20.6% | $ 963,888 |
| Purchased power in thousands of MWhs | 8,510 | -17.0% | 10,248 | -20.5% | 12,894 |
| Average cost per MWh of Purchased power | $ 80.92 | 8.4% | $ 74.63 | -0.2% | $ 74.75 |

Purchased power costs decreased for the year ended December 31, 2007 compared to the same period in 2006 primarily due to a decrease in volume. The average cost per MWh increased due to fixed capacity charges associated with long term Qualified Facility contracts and other mid to long term contracts, coupled with a decrease in volume for the year. Also contributing to the increase in average cost of MWh was hotter weather, particularly during the third quarter 2007, which increased the demand for electricity and therefore required NPC to purchase additional power at peak rates.

NPC's purchased power costs decreased in 2006 compared to 2005, primarily due to an increase in internal generation with the addition of the Silverhawk and Lenzie plants. As a result, the volume of MWh purchased decreased compared to the prior year.

**Fuel for Power Generation**

| | 2007 | | 2006 | | 2005 |
|---|---|---|---|---|---|
| | Amount | Change from Prior year | Amount | Change from Prior year | Amount |
| **Fuel for Power Generation** | $ 594,382 | 7.5% | $ 552,959 | 99.6% | $ 277,083 |
| Thousands of MWhs generated | 14,520 | 19.4% | 12,160 | 50.2% | 8,094 |
| Average fuel cost per MWh of Generated Power | $ 40.94 | -10.0% | $ 45.47 | 32.8% | $ 34.23 |

Fuel for power generation increased for the year ended December 31, 2007, as compared to the same time period in 2006 primarily due to an increase in volume. The additions of Silverhawk and Lenzie, which are highly efficient generating plants, greatly increased NPC's ability to generate power at economical rates. As a result volume has increased significantly in 2007 when compared to 2006. Also contributing to the increase in volume was a 2.8% growth in total system demand as a result of hotter weather and customer growth. The average cost per MWh decreased primarily due to lower natural gas prices and efficiency of the Lenzie and Silverhawk plants.

Fuel for power generation increased in 2006 as compared to 2005 due to several factors:

- With the addition of Silverhawk and Lenzie it was more economical for NPC to rely on its own generation rather than the purchase of power. As a result, the increase in volume of MWh's generated increased significantly compared to the prior year.
- The shutdown of Mohave as of the beginning of 2007 increased the cost per MWh of generated power. Although Silverhawk and Lenzie are highly efficient generation stations, the cost of coal is substantially lower than the cost of natural gas. Mohave generation during 2005 represented approximately 17% of total generation.
- Hedging instruments purchased when gas prices were escalating as a result of the 2005 hurricanes in the southern United States increased fuel for power generation costs. The settlement of these instruments during 2006 negatively impacted the average cost per MWh as natural gas prices were decreasing during this period.

**Deferral of Energy Costs – Net**

| | 2007 | | 2006 | | 2005 |
|---|---|---|---|---|---|
| | Amount | Change from Prior year | Amount | Change from Prior year | Amount |
| Reinstatement of deferred energy | $ - | N/A | $ (178,825) | N/A | $ - |
| Deferral of energy costs-net | 233,166 | 152.6% | 92,322 | 302.2% | (45,668) |
| | $ 233,166 | 369.5% | $ (86,503) | -89.4 % | $ (45,668) |

Reinstatement of deferred energy represents the July 2006 decision by the Nevada Supreme Court which allowed NPC to recover $178.8 million of previously disallowed deferred energy costs. In March 2007, the PUCN approved the settlement agreement allowing NPC to recover such costs. Reference further discussion in Note 3, Regulatory Actions of the Notes to Financial Statements.

Deferred energy costs – net represent the difference between actual fuel and purchased power costs incurred during the period and amounts recoverable through current rates. To the extent actual costs exceed amounts recoverable through current rates, the excess is recognized as a reduction in costs. Conversely to the extent actual costs are less than amounts recoverable through current rates, the difference is recognized as an increase in costs. Deferred energy costs – net also include the current amortization of fuel and purchased power costs previously deferred. See Note 1, Summary of Significant Accounting Policies, Deferral of Energy Costs of the Notes to Financial Statements for further detail of deferred energy balances.

Amounts for 2007, 2006 and 2005 include amortization of deferred energy costs of $177.3 million, $120.5 million and $131.5 million, respectively; and an over-collection of amounts recoverable in rates of $55.8 million in 2007, and an under-collection of $28.2 million and $177.1 million in 2006 and 2005, respectively.

**Allowance for Funds Used During Construction (AFUDC)**

| | 2007 | | 2006 | | 2005 |
|---|---|---|---|---|---|
| | Amount | Change from Prior year | Amount | Change from Prior year | Amount |
| Allowance for other funds used during construction | $ 15,861 | 34.9% | $ 11,755 | -37.1% | $ 18,683 |
| Allowance for borrowed funds used during construction | 13,196 | 13.6% | 11,614 | -49.9% | 23,187 |
| | $ 29,057 | 24.3% | $ 23,369 | -44.2% | $ 41,870 |

AFUDC was higher in 2007 compared to 2006 primarily due to construction of the Clark Peaking Units partially offset by the completion of the Lenzie Blocks 1 and 2 in early spring of 2006.

AFUDC for NPC was lower in 2006 compared to 2005 due to a decrease in Construction Work in Progress (CWIP) balance on which AFUDC is calculated. The decrease in the average CWIP balance was primarily due to the completion of Blocks 1 and 2 of the Chuck Lenzie Station and Harry Allen Unit 4 in early spring of 2006.

**Other (Income) and Expenses**

| | 2007 | | 2006 | | 2005 |
|---|---|---|---|---|---|
| | Amount | Change from Prior year | Amount | Change from Prior year | Amount |
| Other operating expense | $ 232,610 | 6.6% | $ 218,120 | 3.4% | $ 211,039 |
| Maintenance expense | $ 67,482 | 9.0% | $ 61,899 | 18.9% | $ 52,040 |
| Depreciation and amortization | $ 152,139 | 7.5% | $ 141,585 | 14.1% | $ 124,098 |
| Interest charges on long-term debt | $ 164,002 | -4.2% | $ 171,188 | 7.6% | $ 159,106 |
| Interest for energy suppliers | $ - | N/A | $ - | N/A | $ (14,825) |
| Interest charges-other | $ 23,861 | 40.0% | $ 17,038 | 25.6% | $ 13,563 |
| Carrying charge for Lenzie | $ (16,080) | 51.9% | $ (33,440) | N/A | $ - |
| Interest accrued on deferred energy | $ (14,213) | 35.1% | $ (21,902) | -7.6% | $ (20,350) |
| Other income | $ (14,423) | 15.1% | $ (16,992) | 33.7% | $ (25,626) |
| Other expense | $ 11,352 | 33.9% | $ 8,480 | -0.5% | $ 8,525 |

Other operating expense increased in 2007 compared to 2006 as a result of higher operating expenses for Navajo, operating costs associated with the Centennial Transmission line that was placed in service in 2007, increased costs for claims, legal fees and higher regulatory amortizations, partially offset by lower consulting fees and the reversal of Enron legal fees, which are now being recovered in rates as a result of NPC's Western Energy Crisis Rate Case, see Note 3, Regulatory Actions of the Notes to Financial Statements for further discussion. Additionally, in 2006, operating expenses were lower primarily as a result of the settlement of contingency fees associated with Enron in the second quarter and a reallocation of expenses to our joint facility partner which decreased other operating expenses.

Other operating expense increased in 2006 compared to 2005 due to various costs all of which were not individually significant. These increases were partially offset by a decrease in legal fees and operating expense related to Mohave, Reid Gardner and Clark compared to 2005.

Maintenance expense increased for 2007 compared to 2006 mainly due to the operation of Lenzie Units 1 and 2, which were placed in service in January 2006 and April 2006, respectively, the timing of outages at Reid Gardner (forced outages and scheduled maintenance in 2007 and deferred maintenance in 2006) and forced outages at Harry Allen in 2007. Also contributing to the increase were costs incurred to implement new transmission compliance requirements. These expenses were partially offset by scheduled and forced outages at Clark Station in 2006 and deferred maintenance in 2007.

The increase in Maintenance expense in 2006 compared to 2005 was primarily due to the addition of Lenzie and Silverhawk Generating Stations in 2006; partially offset by reduced maintenance expenses for Mohave and Navajo.

Depreciation and amortization increased for the year ended December 31, 2007 compared to the same period in 2006 primarily due to the inclusion of Lenzie in depreciation, beginning June 2007, as a result of NPC's 2006 GRC, an adjustment for Silverhawk depreciation based on regulatory clarification, an increase to plant-in-service for Harry Allen Unit IV in May 2006, an increase to plant-in service for Centennial Transmission Project in March 2007, partially offset by the overall reduction in depreciation rates, as ordered by PUCN in NPC's 2006 GRC.

Depreciation and amortization increased in 2006 compared to 2005 primarily as a result of increases in plant-in-service. The increase is primarily due to the purchase of Silverhawk and completion of the Harry Allen Unit IV.

Interest charges on Long-Term Debt decreased for the year ended December 31, 2007, compared to 2006 due primarily to various re-financings of debt in 2006 and 2007 at lower interest rates and a decrease in the use of the Revolving Credit Facility in 2007. Interest expense for the Revolving Credit Facility was approximately $6.5 million compared to $12 million in the prior year.

Interest charges on Long-Term Debt increased for the year ended December 31, 2006, compared to 2005, due primarily to the issuance in January 2006 of $210 million Series M, General and Refunding Mortgage Notes and the use of the Revolving Credit Facility, partially offset by various re-financings of debt at lower interest rates. The $210 million was issued to fund the acquisition of the Silverhawk Generating Facility. Interest charges related to this issuance was approximately $11.9 million. NPC's use of the Revolving Credit Facility increased in 2006 primarily due to increased capital expenditures and fuel and purchased power expenses. Interest expense for the Revolving Credit Facility was approximately $12 million compared to $1.9 million in the prior year. See Note 6, Long-Term Debt of the Notes to Financial Statements for additional information regarding long-term debt.

NPC's interest charges for energy suppliers are comprised of interest accruals for terminated supplier balances that had been subject to litigation. The amount reported in 2005 includes reversals of accrued balances due to settlements reached with suppliers.

See Note 13, Commitments and Contingencies of the Notes to Financial Statements, for more information regarding the Enron litigation.

Interest charges-other increased for the year ended December 31, 2007, when compared to the same period in 2006, due to amortization of debt issuances and redemption costs, as well as additional interest associated with customer transmission deposits, and lease of property.

Interest charges-other increased for the year ended December 31, 2006, when compared to the same period in 2005, due to higher costs related to new debt issues and redemptions. See Note 6, Long-Term Debt of the Notes to Financial Statements, for additional information regarding long-term debt.

Carrying charges on Lenzie represent carrying charges earned on the incurred debt component of the acquisition and construction costs of the completed Lenzie Generating Station. The PUCN authorized NPC to accrue a carrying charge for the cost of acquisition and construction until the plant is included in rates. Carrying charges decreased for the year ended December 31, 2007, as compared to the same period in 2006, as a result of NPC's 2006 GRC, which includes the cost of Lenzie in rates. See Note 1, Summary of Significant Accounting Policies, of the Notes to Financial Statements for discussion of the accounting for the carrying charge for Lenzie and Note 3, Regulatory Actions of the Notes to Financial Statements for discussion of NPC's 2006 GRC.

Interest accrued on deferred energy decreased for the year ended December 31, 2007, when compared to the same period in 2006, due to lower deferred energy balances, partially offset by carrying charges associated with NPC's Western Energy Crisis Rate Case, which began June 1, 2007.

Interest accrued on deferred energy for the year ended December 31, 2006, were slightly higher than the same period in 2005 due to slightly higher average deferred energy balances during 2006, excluding deferred energy assets of $179 million associated with the Nevada Supreme Court decision reversing the deferred energy costs disallowance. See Note 1, Summary of Significant Accounting Policies of the Notes to Financial Statements for further details of deferred energy balances and Note 3, Regulatory Actions of the Notes to Financial Statements for further discussion of deferred energy accounting issues.

Reinstated interest on deferred energy represents the carrying charges which were previously expensed as a result of the PUCN's decision on NPC's 2001 Deferred Energy Case. In March 2007, the PUCN approved a settlement agreement allowing NPC to recover past carrying charges. See Note 3, Regulatory Actions of the Notes to Financial Statements for discussion.

Other income decreased for the year ended December 31, 2007, compared to the same period in 2006, due to lower interest income, and the adjustment for and expiration of the amortization of gains associated with the disposition of property. Other income decreased for the year ended December 31, 2006 compared to the same period in 2005 due primarily to the lower amortization of gains associated with disposition of SO2 allowances and the expiration of the amortization associated with the disposition of property offset slightly by higher interest income

Other expense increased for the year ended December 31, 2007 compared to the same period in 2006 due primarily to costs associated with the Energy Savings Project for the Clark County School District, as agreed upon in the Reid Gardner Consent Decree discussed in Note 13, Commitments and Contingencies of the Notes to Financial Statements. Other expense was comparable for 2006 to 2005.

## ANALYSIS OF CASH FLOWS

NPC's cash flows increased during the year ended December 31, 2007, when compared to the same period in 2006 due to an increase in cash from operating activities offset by a decrease in cash from financing activities and an increase in cash used by investing activities.

***Cash From Operating Activities.*** Cash flows from operating activities increased during the year ended December 31, 2007 compared to the same period in 2006 primarily due to increased operating income (excluding Reinstated Deferred Energy). Operating income (excluding Reinstated Deferred Energy) increased primarily as a result of increases in rates due to NPC's GRC, the Western Energy Crisis Rate Case and the 2001 Deferred Energy Case as discussed in Note 3, Regulatory Actions of the Notes to Financial Statements.

In addition, operating cash flow (excluding Reinstated Deferred Energy) increased as a result of:

- a decrease in payments made to suppliers;
- the timing of payments;
- improved credit terms with vendors, resulting in a decrease in deposits and prepayments;
- a BTER rate which better reflects actual fuel and purchased power costs;
- a decrease in interest expense paid; and

- the net settlement with Enron in 2006.

This was partially offset by an increase in payments for Pension and Other Post Retirement Benefits of $60.5 million.

***Cash Used By Investing Activities.*** Cash used by investing activities for the year ended December 31, 2007 increased compared to the same period in 2006. The increase is primarily due to 2007 expenditures for the Clark Peaking Units, the Ely Energy Center and utility infrastructure to support the growth in the Las Vegas area, compared to expenditures for the Silverhawk and the Lenzie Generating Station in 2006.

***Cash From Financing Activities.*** Cash flows from financing activities decreased for the year ended December 31, 2007 compared to the same period in 2006 due to a decrease in financing activities and capital contributions from SPR. Financing activities decreased as a result of the utilization of cash generated from operating activities.

NPC's cash flows increased during the year ended December 31, 2006, compared to the same period in 2005, due to an increase in cash from financing activities and a slight increase in cash from operating activities offset partially by an increase in cash used by investing activities. Cash from financing activities increased for the year ended December 31, 2006 when compared to the same period in 2005 primarily as a result of increased debt offerings partially offset by the retirement of debt. In 2006, SPR contributed capital of $200 million to NPC and NPC paid dividends to SPR of approximately $35.8 million. Cash from operating activities increased during the year ended December 31, 2006 compared to the same period in 2005 due to rate increases for deferred energy and a decrease in accounts receivable, offset by a decrease in collections for deferred energy balances due to the ending of collection periods and a reduction in accounts payable primarily associated with purchased power suppliers. The increase was also offset by the net settlement with Enron. Cash used by investing activities increased for the year ended December 31, 2006 when compared to the same period in 2005 primarily due to the acquisition of Silverhawk and improvements at other generating stations, offset by a reduction in spending at the Lenzie plant that was placed in service in 2006.

## LIQUIDITY AND CAPITAL RESOURCES

### Overall Liquidity

NPC's primary source of operating cash flows is electric revenues, including the recovery of previously deferred energy costs. Significant uses of cash flows from operations include the purchase of electricity and natural gas, other operating expenses, capital expenditures and the payment of interest on NPC's outstanding indebtedness. Operating cash flows can be significantly influenced by factors such as weather, regulatory outcome, and economic conditions.

Available Liquidity as of December 31, 2007 (in millions)

| | NPC |
|---|---|
| Cash and Cash Equivalents | $ 37.0 |
| Balance available on Revolving Credit Facility | 595.1 |
| | $ 632.1 |

[1] As of February 22, 2008, NPC had approximately $594.9 million available under its revolving credit facility.

In 2007, SPR contributed capital, using proceeds from its December 2007 common stock offering, to NPC of approximately $65 million. NPC used the proceeds to repay indebtedness under its revolving credit facility and for general corporate purposes. In January 2008, SPR contributed additional capital to NPC of approximately $53 million for general corporate purposes.

In 2007, NPC paid $28.2 million in dividends to SPR and an additional $10.8 million, declared in November 2007, was outstanding as of December 31, 2007. The remaining $10.8 million was paid in January 2008. In February 2008, NPC declared a dividend to SPR for approximately $14.0 million.

NPC anticipates that it will be able to meet short-term operating costs, such as fuel and purchased power costs, with internally generated funds, including the recovery of deferred energy and the use of its revolving credit facility. To manage liquidity needs as a result of seasonal peaks in fuel requirement, NPC may use hedging activities. However, to fund long-term capital requirements, as discussed below, NPC may meet such financial obligations with a combination of internally generated funds, the use of the revolving credit facility and the issuance of long-term debt, preferred securities, and/or capital contributions from SPR.

Continued improvement in the credit ratings of NPC (see Credit Ratings below) has strengthened the liquidity position of the company by allowing for the resumption of normal payment terms with our counterparties and the elimination of cash collateral requirements. Existing collateral requirements with counterparties have been satisfied with letters of credit. The recent credit rating upgrades reduce the cost of borrowing under NPC's revolving credit facility. In addition, the upgrades have the potential to provide NPC better access to capital markets and to reduce the cost of issuing additional long-term debt. However, disruptions in the banking

and capital markets not specifically related to NPC may affect its ability to access funding sources or cause an increase in the return required by investors.

NPC designs operating and capital budgets to control operating costs and capital expenditures. In addition to operating expenses, NPC has continuing commitments for capital expenditures for construction, improvement and maintenance of facilities.

Detailed below are NPC's Capital Structure, Capital Requirements, Contractual Obligations, recently completed Financing Transactions and Factors Affecting Liquidity, including our ability to obtain debt on favorable terms.

**Capital Structure**

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

| | 2007 | | 2006 | |
|---|---|---|---|---|
| Current Maturities of Long-Term Debt | $ 8,642 | 0.2% | $ 5,948 | 0.1% |
| Long-Term Debt | 2,528,141 | 51.4% | 2,380,139 | 52.2% |
| Common Equity | 2,376,740 | 48.4% | 2,172,198 | 47.7% |
| Total | $ 4,913,523 | 100.0% | $ 4,558,285 | 100.0% |

**Capital Requirements**

*Construction Expenditures*

NPC's cash construction expenditures have increased since 2004 and are expected to continue to increase due to programs designed to meet electric load growth and reliability needs. Cash construction expenditures for the years ended 2007, 2006 and 2005 were approximately $732 million, $627 million, and $478 million, respectively. NPC's cash requirement for construction expenditures for 2008 are projected to be $949.8 million. NPC's cash requirement for construction expenditures for 2008 through 2012 are projected to be $5.9 billion. To fund these capital projects NPC may meet such financial obligations with a combination of internally generated funds, the use of its revolving credit facility, the issuance of long-term debt, and if necessary, capital contributions from SPR.

*Contractual Obligations*

The table below provides NPC's consolidated contractual obligations 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. Certain contracts contain variable factors which required NPC to estimate the obligation depending on the final variable amount. Actual amounts could differ. The table does not include estimated construction expenditures described above, except for major capital projects for which NPC has executed contracts by December 31, 2007. Additionally, at December 31, 2007, NPC has recorded a $20.1 million liability in accordance with FIN 48, all of which is classified as non-current. NPC is unable to make a reasonably reliable estimate of the period of cash payments to relevant tax authorities; consequently, none of the FIN 48 liability is included in the contractual obligations table below (dollars in thousands):

| | Payment Due by Period | | | | | | |
|---|---|---|---|---|---|---|---|
| | 2008 | 2009 | 2010 | 2011 | 2012 | Thereafter | Total |
| Long-Term Debt Maturities | $ 12 | $ 15,000 | $ - | $ 364,000 | $ 130,000 | $1,979,079 | $2,488,091 |
| Long-Term Debt Interest Payments | 162,185 | 161,987 | 161,397 | 144,367 | 125,794 | 1,748,600 | 2,504,330 |
| Purchased Power | 349,322 | 286,016 | 338,323 | 372,613 | 394,765 | 5,151,777 | 6,892,816 |
| Coal and Natural Gas | 264,564 | 57,140 | 49,400 | 41,018 | 28,429 | 156,410 | 596,961 |
| Long-Term Service Agreements(1) | 17,144 | 17,144 | 17,144 | 17,144 | 17,144 | 113,607 | 199,327 |
| Capital Projects(2) | 190,565 | 72,425 | 2,873 | - | - | - | 265,863 |
| Operating Leases | 10,391 | 9,630 | 8,947 | 6,027 | 4,142 | 33,961 | 73,098 |
| Capital Leases | 7,158 | 7,218 | 8,004 | 5,924 | 6,449 | 26,671 | 61,424 |
| Total Contractual Cash Obligations | $1,001,341 | $626,560 | $ 586,088 | $951,093 | $ 706,723 | $ 9,210,105 | $13,081,910 |

(1) Includes long term service agreements for the Chuck Lenzie Generation Station and the Silverhawk Facility.

(2) Capital Projects include tenant improvement project for the Southern Operations Center, Harry Allen Combined Cycle Project, Clark Peaking Unit Turbine agreement, Clark Peaking Units EPC agreement, and the Clark 5-8 Dry Low Nox Burner project.

**Pension Plan Matters**

SPR has a qualified pension plan that covers substantially all employees of SPR, NPC and SPPC. The annual net benefit cost for the plan is expected to decrease in 2008 to $25.1 million compared to the 2007 cost of $29.3 million. As of September 30, 2007, the measurement date, the plan was under funded on a FAS 158 pension benefit obligation basis. Refer to Note 11, Retirement Plan and Post-Retirement Benefits, of the Notes to Financial Statements. During 2007, SPR contributed a total of $54 million to meet their funding obligations under the plan. At the present time it is not expected that any additional funding will be required in 2008 to meet the minimum funding level requirements defined by the Pension Benefit Guaranty Corporation and ERISA.

**Financing Transactions**

*6.75% General and Refunding Mortgage Notes, Series R*

On June 28, 2007, NPC issued and sold $350 million of its 6.750% General and Refunding Mortgage Notes, Series R, due July 1, 2037. The Series R Notes were issued pursuant to a registration statement previously filed with the Securities and Exchange Commission. The net proceeds from the issuance were used to fund the purchase of the tendered Series G Notes (discussed below), repay amounts outstanding under NPC's revolving credit facility, and for general corporate purposes.

*Tender Offer for General and Refunding Mortgage Notes, Series G*

On June 28, 2007, NPC settled its cash tender offer, which commenced on June 15, 2007 and expired on June 22, 2007, for its 9.00% General and Refunding Mortgage Notes, Series G, due 2013. Those holders who tendered their notes by the expiration date were entitled to receive a purchase price of $1,079.75 per $1,000 principal amount of Series G Notes. Approximately $210.3 million of the $227.5 million Series G Notes outstanding were validly tendered and accepted by NPC.

**Factors Affecting Liquidity**

*Financial Covenants*

NPC's $600 million Second Amended and Restated Revolving Credit Agreement dated November 2005, and amended in April 2006, contains two financial maintenance covenants. The first requires that NPC maintain a ratio of consolidated indebtedness to consolidated capital, determined as of the last day of each fiscal quarter, not to exceed 0.68 to 1. The second requires that NPC maintain a ratio of consolidated cash flow to consolidated interest expense, determined as of the last day of each fiscal quarter for the period of four consecutive fiscal quarters, not to be less than 2.0 to 1. As of December 31, 2007, NPC was in compliance with these covenants.

*Ability to Issue Debt*

Certain factors impact NPC's ability to issue debt:

1. Financing Authority from the PUCN: On June 22, 2007, NPC received PUCN authorization to enter into financings of $3.91 billion through 2009. Of this total, $1.35 billion is contingent upon the PUCN's approval of the Ely Energy Center in 2008. The remaining authority, $2.56 billion, includes authority for the revolving credit facility, and authority to issue new debt and to refinance existing debt. As of December 31, 2007, NPC used $600 million of the $2.56 billion authority for the revolving credit facility, and $350 million for the issuance of the 6.75% General and Refunding Mortgage Notes, Series R (see Financing Transactions, above). As such, approximately $1.6 billion of the authority remains.

2. Financial Covenants in its and SPR's financing agreements. The terms of certain SPR debt prohibit NPC and SPPC from incurring additional indebtedness unless certain conditions have been met. See SPR's Ability to Issue Debt. In addition to the SPR debt, the terms of NPC's Series G, I and L General and Refunding Mortgage Notes which mature in 2013, 2012, and 2015, respectively, collectively (NPC's Debt) restrict NPC from incurring any additional indebtedness unless certain covenants are satisfied. However, as of December 31, 2007, the financial covenants under NPC's Debt allow for greater borrowings than SPR's cap on additional indebtedness; therefore, NPC is limited by SPR's cap on additional consolidated indebtedness of $1.1 billion. If NPC's Series G, I or L General and Refunding Mortgage Notes are upgraded to investment grade by S&P,the restrictions imposed by those Notes will be suspended and will no longer be in effect so long as the applicable series of securities remain investment grade by both Moody's and S&P.

Since SPR's debt covenant limitations are calculated on a consolidated basis, SPR's debt covenant limitations may allow for higher or lower borrowing than $1.1 billion, depending on the Utilities' combined outstanding balances under their revolving credit facilities at the time of the covenant calculations.

*Ability to Issue General and Refunding Mortgage Securities*

To the extent that NPC has the ability to issue debt under the most restrictive covenants in its financing agreements and has financing authority to do so from the PUCN, NPC's ability to issue secured debt is still limited by the amount of bondable property or retired bonds that can be used to issue debt under NPC's General and Refunding Mortgage Indenture ("Indenture").

The Indenture creates a lien on substantially all of NPC's properties in Nevada. As of December 31, 2007, $2.8 billion of NPC's General and Refunding Mortgage Securities were outstanding. NPC had the capacity to issue $758 million of General and Refunding Mortgage Securities as of December 31, 2007. That amount is determined on the basis of:

1. 70% of net utility property additions;
2. the principal amount of retired General and Refunding Mortgage Securities; and/or
3. the principal amount of first mortgage bonds retired after October 2001.

Property Additions include plant in service and specific assets in construction work in progress. The amount of bond capacity listed above does not include eligible property in construction work in progress.

NPC also has the ability to release property from the lien of the mortgage indenture 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.

*Credit Ratings*

NPC is rated by four Nationally Recognized Statistical Rating Organizations: DBRS, Fitch, Moody's and S&P. As of February 22, 2008, the ratings are as follows:

| | | Rating Agency | | | |
|---|---|---|---|---|---|
| | | DBRS | Fitch | Moody's | S&P |
| NPC | Sr. Secured Debt | BBB (low)* | BBB-* | Baa3* | BB+ |
| NPC | Sr. Unsecured Debt | Not rated | BB | Not rated | B |

* Ratings are investment grade

Three of the four rating agencies currently rate NPC's senior secured debt investment grade. Moody's and DBRS's rating outlook for NPC is Stable. In June 2007, S&P and Fitch revised their outlook on NPC to Positive from Stable.

A security rating is not a recommendation to buy, sell or hold securities. Security ratings are subject to revision and withdrawal at any time by the assigning rating organization, and each rating should be evaluated independently of any other rating.

*Credit Ratings of Bond Insurers*

Recent sub-prime mortgage issues have adversely affected the overall financial markets, generally resulting in increased interest rates, reduced access to the capital markets, and actual or potential downgrades of bond insurers, among other negative matters. The interest rates on certain issues of NPC's, Variable Rate Notes of approximately $207.5 million, as presented in its Consolidated Statements of Capitalization are periodically reset through auction processes. These securities are supported by bond insurance policies provided by either Ambac, or FGIC (collectively, the "Insurers"), and the interest rates on those securities are directly affected by the rating of the bond insurer due to, among other things, the impact that such ratings have on the success or failure of the auction process. The uncertainty with the Insurers' credit quality has had an impact on NPC's interest costs for these specific securities in the fourth quarter of 2007, although not significant. However, if the credit quality of the Insurers continues to deteriorate, NPC could experience higher interest costs for these securities.

*Energy Supplier Matters*

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

Under these contracts, a material adverse change in NPC would allow the counterparty to request adequate financial assurance, which, if not provided within three business days, could cause a default. A default must be declared within 30 days of the event, giving rise to the default becoming known. A default will result in a termination payment equal to the present value of the net gains and losses for the entire remaining term of all contracts between the parties aggregated to a single liquidated amount due within three business days following the date the notice of termination is received. The mark-to-market value, which is substantially based on quoted market prices, can be used to roughly approximate the termination payment and benefit at any point in time. The net mark-to-market value as of December 31, 2007 for all suppliers continuing to provide power under a WSPP agreement would approximate a $10.1 million payment by NPC. These contracts qualify for the normal purchases scope exception of SFAS No. 133, and as such, are not required to be mark-to-market on the balance sheet. Refer to Note 9, Derivatives and Hedging Activities, of the Notes to Financial Statements for further discussion.

*Gas Supplier Matters*

With respect to the purchase and sale of natural gas, NPC uses several types of standard industry contracts. The natural gas contract terms and conditions are more varied than the electric contracts. Consequently, some of the contracts contain language similar to that found in the WSPP agreement and other agreements have unique provisions dealing with material adverse changes. Because of creditworthiness concerns, most contracts and confirmations for natural gas purchases have been modified or separate agreements have been made to either shorten the normal payment due date or require payment in advance of delivery. At the present time, no counter-parties require payment in advance of delivery.

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

*Cross Default Provisions*

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

## SIERRA PACIFIC POWER COMPANY

## RESULTS OF OPERATIONS

SPPC recognized net income of $65.7 million for the year ended December 31, 2007 compared to net income of $57.7 million in 2006 and a net income of $52.1 million in 2005. SPPC's operating results for 2007 increased over 2006 primarily as a result of decreased interest charges and increased AFUDC due to the construction of Tracy. SPPC's operating results for 2006 increased over 2005 primarily as a result of increased operating revenues.

In February 2008, SPPC declared a dividend to SPR for approximately $8.0 million. In 2007, SPPC paid $14.2 million in dividends to SPR and declared an additional $5.3 million dividend. In 2006, SPPC paid $17.9 million in dividends to SPR and declared an additional $6.7 million dividend. In January 2007, SPPC paid the $6.7 million dividend to SPR.

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, which is a "non-GAAP financial measure" as defined in accordance with SEC rules, 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.

SPPC believes presenting gross margin allows the reader to assess the impact of SPPC's regulatory treatment and its overall regulatory environment on a consistent basis. Gross margin, as a percentage of revenue, is primarily impacted by the fluctuations in regulated electric and natural gas supply costs versus the fixed rates collected from customers. While these fluctuating costs impact gross margin as a percentage of revenue, they only impact gross margin amounts if the costs cannot be passed through to customers. Gross margin, which SPPC calculates as operating revenues less fuel and purchased power costs, provides a measure of income available to support the other operating expenses of SPPC. Gross margin changes based on such factors as general base rate adjustments (which are required to be filed by statute every two years) and reflect SPPC's strategy to increase internal power generation versus purchased power, which generates no gross margin.

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

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2007 | Change from Prior Year | 2006 | Change from Prior Year | 2005 |
| Operating Revenues: | | | | | |
| Electric | $ 1,038,867 | 1.8% | $ 1,020,162 | 5.5% | $ 967,427 |
| Gas | 205,430 | -2.2% | 210,068 | 17.8% | 178,270 |
| | $ 1,244,297 | 1.1% | $ 1,230,230 | 7.4% | $ 1,145,697 |
| Energy Costs: | | | | | |
| Purchased power | $ 348,299 | 1.1% | $ 344,590 | -2.1% | $ 352,098 |
| Fuel for power generation | 242,973 | -1.9% | 247,626 | 6.0% | 233,653 |
| Gas purchased for resale | 150,879 | -6.1% | 160,739 | 14.1% | 140,850 |
| Deferral of energy costs-electric-net | 63,873 | 35.8% | 47,043 | 480.1% | 8,110 |
| Deferral of energy costs-gas-net | 10,763 | 54.9% | 6,947 | -1027.5% | (749) |
| | $ 816,787 | 1.2% | $ 806,945 | 9.9% | $ 733,962 |
| Energy Costs by Segment: | | | | | |
| Electric | $ 655,145 | 2.5% | $ 639,259 | 7.6% | $ 593,861 |
| Gas | 161,642 | -3.6% | 167,686 | 19.7% | 140,101 |
| | $ 816,787 | 1.2% | $ 806,945 | 9.9% | $ 733,962 |
| Gross Margin by Segment before Deferred Energy Costs Disallowed: | | | | | |
| Electric | $ 383,722 | 0.7% | $ 380,903 | 2.0% | $ 373,566 |
| Gas | 43,788 | 3.3% | 42,382 | 11.0% | 38,169 |
| | $ 427,510 | 1.0% | $ 423,285 | 2.8% | $ 411,735 |
| Deferred energy costs disallowed[1] | 14,171 | N/A | - | N/A | - |
| Gross Margin by Segment after Deferred Energy Costs Disallowed: | | | | | |
| Electric | $ 369,551 | -3.0% | $ 380,903 | 2.0% | $ 373,566 |
| Gas | 43,788 | 3.3% | 42,382 | 11.0% | 38,169 |
| | $ 413,339 | -2.3% | $ 423,285 | 2.8% | $ 411,735 |

(1) For further discussion on the $14.2 million deferred energy costs disallowed see Note 3, Regulatory Actions of the Notes to Financial Statements.

SPPC's electric gross margin before deferred energy costs disallowed increased slightly for the year ended 2007 compared to the same period in 2006, primarily due to customer growth, this was partially offset by a decrease in revenue per MWh for commercial and industrial customers and usage per industrial customers.

SPPC's gas gross margin increased slightly for the year ended 2007 compared to the same period in 2006, primarily due to customer growth, partially offset by a decrease in usage by customers due to warmer weather, and a decrease in BTGR rates as a result of SPPC's gas GRC.

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

| | 2007 | | 2006 | | 2005 |
|---|---|---|---|---|---|
| | Amount | Change from Prior year | Amount | Change from Prior year | Amount |
| **Electric Operating Revenues:** | | | | | |
| Residential | $ 330,557 | 3.6% | $ 319,140 | 12.9% | $ 282,655 |
| Commercial | 384,364 | 3.7% | 370,617 | 13.9% | 325,456 |
| Industrial | 293,270 | -2.0% | 299,163 | -10.3% | 333,621 |
| Retail revenues | 1,008,191 | 1.9% | 988,920 | 5.0% | 941,732 |
| Other | 30,676 | -1.8% | 31,242 | 21.6% | 25,695 |
| **Total Revenues** | $ 1,038,867 | 1.8% | $ 1,020,162 | 5.5% | $ 967,427 |
| Retail sales in thousands of megawatt-hours (MWh) | 8,773 | 0.7% | 8,711 | -5.7% | 9,234 |
| Average retail revenue per MWh | $ 114.92 | 1.2% | $ 113.53 | 11.3% | $ 101.99 |

SPPC's retail revenues increased in 2007 compared to 2006 primarily due to customer growth and increases in retail rates. The number of residential, commercial, and industrial customers increased (1.6%, 3.0%, and 5.4% respectively). Retail rates increased as a result of SPPC's various general, energy, and deferred energy cases. See Note 3, Regulatory Actions of the Notes to Financial Statements. These increases were partially offset by lower industrial energy revenues and MWh's as a result of two large industrial customers moving to distribution-only service and standby service.

SPPC's retail revenues increased in 2006 as compared to 2005 primarily due to increases in retail rates and to a lesser extent customer growth. Retail rates increased as a result of SPPC's various BTER and Deferred Energy. (Refer to Note 3, Regulatory Actions of the Notes to Financial Statements). The number of residential, commercial, and industrial customers increased (2.8%, 3.0%, and 2.1% respectively). These increases were offset by lower industrial energy revenues and MWh's as a result of SPPC's large industrial customer, Barrick Gold, moving to distribution-only services effective December 1, 2005.

The decrease in Electric Operating Revenues – Other in 2007 compared to 2006, was primarily due to a decrease in the amortization of impact charges resulting from Barrick becoming a distribution-only services customer.

The increase in Electric Operating Revenues – Other in 2006 compared to 2005, was primarily due to the amortization of impact charges and increased wheeling revenues resulting from Barrick becoming a distribution-only services customer.

**Gas Operating Revenues**

| | 2007 | | 2006 | | 2005 |
|---|---|---|---|---|---|
| | Amount | Change from Prior Year | Amount | Change from Prior Year | Amount |
| **Gas Operating Revenues:** | | | | | |
| Residential | $ 117,871 | -2.4% | $ 120,734 | 25.4% | $ 96,292 |
| Commercial | 53,551 | -1.4% | 54,316 | 22.6% | 44,286 |
| Industrial | 20,145 | -1.8% | 20,509 | 21.0% | 16,953 |
| Retail revenues | 191,567 | -2.0% | 195,559 | 24.1% | 157,531 |
| Wholesale | 11,116 | -4.6% | 11,650 | -34.5% | 17,786 |
| Miscellaneous | 2,747 | -3.9% | 2,859 | -3.2% | 2,953 |
| **Total Revenues** | $ 205,430 | -2.2% | $ 210,068 | 17.8% | $ 178,270 |
| Retail sales in thousands of decatherms | 14,893 | -1.1% | 15,058 | 1.6% | 14,819 |
| Average retail revenues per decatherm | $ 12.86 | -1.0% | $ 12.99 | 22.2% | $ 10.63 |

SPPC's retail gas revenues decreased in 2007 compared to 2006 primarily due to warmer temperatures during 2007 and decreases in retail customer rates. Retail rates decreased as a result of SPPC's Gas GRC and 2006 and 2007 Natural Gas and Propane Deferred Rate Case and BTER updates. See Note 3, Regulatory Actions of the Notes to Financial Statements. Partially offsetting these decreases was the growth in retail customers. The number of residential, commercial and industrial customers increased (2.9%, 3.6% and 12.6%, respectively).

SPPC's retail gas revenues increased in 2006 compared to 2005 primarily due to increases in customer rates and customer growth. Retail rates increased as a result of SPPC's various general, energy and deferred energy rate cases (refer to Note 3, Regulatory Actions of the Notes to Financial Statements). The number of residential, commercial and industrial customers increased (4.3%, 3.7% and 16.7%, respectively).

The wholesale revenues for the year ended December 31, 2007 and 2006 decreased compared to prior years primarily due to decreased availability of gas for wholesale sales.

**Energy Costs**

Energy Costs include Purchased Power and Fuel for Generation. These costs are dependent upon many factors which may vary by season or period. As a result, SPPC's usage and average cost per MWh of Purchased Power versus Fuel for Generation can vary significantly as the company meets the demands of the season. These factors include, but are not limited to:

- Weather
- Plant outages
- Total system demand
- Resource constraints
- Transmission constraints

- Gas transportation constraints
- Natural gas constraints
- Long term contracts
- Mandated power purchases; and
- Generation efficiency

| | 2007 | | 2006 | | 2005 |
|---|---|---|---|---|---|
| | Amount | Change from Prior Year | Amount | Change from Prior Year | Amount |
| Energy Costs | $ 591,272 | -0.2% | $ 592,216 | 1.1% | $ 585,751 |
| Total System Demand | 9,408 | 0.6% | 9,350 | -4.8% | 9,820 |
| Average cost per MWH | $ 62.85 | -0.8% | $ 63.34 | 6.2% | $ 59.65 |

Although the average cost per MWH for Energy costs, as well as, the average cost per MWh of Purchased Power and the average cost per MWH for Fuel for Generation fluctuated considerably during the quarters, energy costs remained relatively stable for the year ended, 2007 compared to 2006. Typically, it is more economical for SPPC to purchase power than to generate in the first two quarters of the year; however transmission capacity constraints limit SPPC's ability to purchase additional power at the lower seasonal rates; therefore it must generate power. Conversely, during the third and fourth quarter, it is more economical for SPPC to rely on internal generation as demand and cost for purchased power increases. However, SPPC is limited by its generation capabilities, therefore, must purchase power to meet its total system demand. If natural gas prices remain relatively stable, SPPC anticipates the addition of the Tracy Generating Station will increase our ability to generate electricity at more economical rates,

Similar to the above, energy costs for 2006 compared to 2005 stayed relatively stable. The total system demand decreased primarily due to a decrease in the volume associated with the loss of Barrick, which transitioned to distribution-only services. The increase was primarily due to hedging instruments which were purchased during the period when gas prices escalated as a result of the 2005 hurricane season.

**Purchased Power**

| | 2007 | | 2006 | | 2005 |
|---|---|---|---|---|---|
| | Amount | Change from Prior Year | Amount | Change from Prior Year | Amount |
| **Purchased Power** | $ 348,299 | 1.1% | $ 344,590 | -2.1% | $ 352,098 |
| Purchased power in thousands Of MWh | 5,376 | 0.8% | 5,334 | -2.0% | 5,441 |
| Average cost per MWh of Purchased power | $ 64.79 | 0.3% | $ 64.60 | -0.2% | $ 64.71 |

SPPC's Purchased Power costs increased slightly in 2007 compared to 2006. The increase was primarily due to the higher than normal purchased power costs during the second quarter of 2007. Typically, in the first half of the year, SPPC is able to purchase hydro power at low prices; however the availability of hydro power can fluctuate from year to year depending on weather. In the first half of 2007, the availability of hydro power was lower compared to 2006 as such purchased power costs were higher. This increase in costs was partially offset by a decrease in purchased power costs in the second half of 2007 as a result of lower natural gas prices.

SPPC's purchased power costs decreased in 2006 compared to 2005 primarily due to a decrease in volume associated with the loss of Barrick, which transitioned to a distribution only services.

**Fuel for Power Generation**

| | 2007 | | 2006 | | 2005 |
|---|---|---|---|---|---|
| | Amount | Change from Prior year | Amount | Change from Prior year | Amount |
| **Fuel for Power Generation** | $ 242,973 | -1.9% | $ 247,626 | 6.0% | $ 233,653 |
| Thousands of MWhs generated | 4,032 | 0.4% | 4,016 | -8.3% | 4,379 |
| Average fuel cost per MWh of Generated Power | $ 60.26 | -2.3% | $ 61.66 | 15.6% | $ 53.36 |

Fuel for power generation and the average fuel cost per MWh decreased in 2007 compared to 2006. The decrease is primarily due to a decrease in natural gas costs in 2007 and higher cost for hedging instruments in 2006.

Fuel for power generation and the average fuel cost per MWh increased in 2006 compared to 2005. The increase is primarily due to hedging instruments which were purchased during the period when gas prices were escalating as a result of the 2005 hurricanes in the southern United States. The settlement of these instruments negatively impacted the average cost per MWh as natural gas prices were decreasing in 2006. The settlements of hedging instruments in the fourth quarter 2005 partially offset the gas cost in 2005. MWH generated decreased as compared to 2005 primarily due to Barrick, which transitioned to distribution-only services in 2006.

**Gas Purchased for Resale**

| | 2007 | | 2006 | | 2005 |
|---|---|---|---|---|---|
| | Amount | Change from Prior Year | Amount | Change from Prior Year | Amount |
| **Gas Purchased for Resale** | $ 150,879 | -6.1% | $ 160,739 | 14.1% | $ 140,850 |
| Gas Purchased for Resale (in thousands of decatherms) | 17,378 | -0.6% | 17,491 | 5.4% | 16,592 |
| Average Cost per decatherm | $ 8.68 | -5.5% | $ 9.19 | 8.2% | $ 8.49 |

The cost of gas purchased for resale and average cost per decatherm decreased in 2007 compared to 2006. The decrease is primarily due to a decrease in natural gas prices which were partially offset by an increase in hedging instrument costs. The volume of gas purchased for resale decreased slightly in 2007 compared to 2006 primarily due to milder winter weather in the beginning of 2007.

The cost of gas purchased for resale increased in 2006 as compared to 2005 due to hedging instruments which were purchased during the period when gas prices were escalating as a result of the 2005 hurricanes in the southern United States. The settlement of these instruments negatively impacted the average cost per decatherm as natural gas prices were decreasing in 2006. The volume of gas purchased for resale increased primarily due to the colder winter weather during the fourth quarter of 2006.

**Deferral of Energy Costs – Net**

| | 2007 | | 2006 | | 2005 |
|---|---|---|---|---|---|
| | Amount | Change from Prior Year | Amount | Change from Prior Year | Amount |
| Deferred energy costs disallowed | $ 14,171 | N/A | $ - | N/A | $ - |
| Deferred energy costs - electric - net | 63,873 | 35.8% | 47,043 | 480.1% | 8,110 |
| Deferred energy costs - gas - net | 10,763 | 54.9% | 6,947 | 1027.5% | (749) |
| Total | $ 88,807 | | $ 53,990 | | $ 7,361 |

Deferred energy costs disallowed represents the November 2007 disallowance by the PUCN of deferred settlement costs incurred to resolve claims arising from the Western Energy Crisis. Reference further discussion in Note 3, Regulatory Actions of the Notes to Financial Statements.

Deferred energy costs – net represents the difference between actual fuel and purchased power costs incurred during the period and amounts recoverable through current rates. To the extent actual costs exceed amounts recoverable through current rates the excess is recognized as a reduction in costs. Conversely to the extent actual costs are less than amounts recoverable through current rates the difference is recognized as an increase in costs. Deferred energy costs – net also include the current amortization of fuel and purchased power costs previously deferred.

Deferred energy costs - electric – net for 2007, 2006 and 2005 reflect amortization of deferred energy costs of $44.1 million, $46.3 million and $56.7 million, respectively; and an over-collection of amounts recoverable in rates of $19.7 million and $0.7 million, in 2007 and 2006 respectively, and an under-collection of $48.6 million in 2005. See Note 1, Summary of Significant Accounting Policies, Deferral of Energy Costs of the Notes to Financial Statements for further detail of deferred energy balances.

Deferred energy costs - gas - net for 2007, 2006 and 2005 reflect amortization of deferred energy costs of $0.7 million, $6.3 million and $1.5 million, respectively; and an over-collection of amounts recoverable in rates of $10.1 million and $0.6 million in 2007 and 2006, respectively, and an under-collection of $2.3 million in 2005.

**Allowance for Funds Used During Construction (AFUDC)**

| | 2007 | | 2006 | | 2005 |
|---|---|---|---|---|---|
| | Amount | Change from Prior Year | Amount | Change from Prior Year | Amount |
| Allowance for other funds used during construction | $ 15,948 | 146.5% | $ 6,471 | 294.8% | $ 1,639 |
| Allowance for borrowed funds used during construction | 12,771 | 132.0% | 5,505 | 266.0% | 1,504 |
| | $ 28,719 | 139.8% | $ 11,976 | 281.0% | $ 3,143 |

AFUDC increased in for the years ended December 31, 2007 and 2006 compared to 2005 primarily due to an increase in the Construction Work-In-Progress (CWIP) balance due to the expansion of the Tracy Generating Station which started in late 2005.

**Other (Income) and Expenses**

| | 2007 | | 2006 | | 2005 |
|---|---|---|---|---|---|
| | Amount | Change from Prior year | Amount | Change from Prior year | Amount |
| Other operating expense | $ 142,348 | 0.7% | $ 141,350 | 7.2% | $ 131,901 |
| Maintenance expense | $ 31,553 | 0.9% | $ 31,273 | 17.2% | $ 26,690 |
| Depreciation and amortization | $ 83,393 | -4.5% | $ 87,279 | -3.6% | $ 90,569 |
| Interest charges on long-term debt | $ 67,502 | -6.1% | $ 71,869 | 3.8% | $ 69,240 |
| Interest for energy suppliers | $ - | N/A | $ - | N/A | $ (2,396) |
| Interest charges-other | $ 6,004 | 16.8% | $ 5,142 | 38.0% | $ 3,727 |
| Interest accrued on deferred energy | $ (865) | -85.6% | $ (5,996) | -15.5% | $ (7,092) |
| Other income | $ (8,091) | -14.0% | $ (9,412) | 58.5% | $ (5,940) |
| Other expense | $ 8,441 | -0.2% | $ 8,422 | 12.4% | $ 7,493 |

Other operating expense increased slightly in 2007 compared to 2006, primarily due to an increase in legal claims, higher regulatory amortizations and in 2006, operating expenses were lower primarily as a result of the settlement of contingency fees associated with Enron in the second quarter.

Other operating expense increased for 2006 compared to 2005 due to increased amortization of regulatory assets resulting from SPPC's GRC, as discussed in Regulatory Proceedings. Also contributing to the increase was the recovery in 2005 of a claim against Pacific Gas and Electric; partially offset by Enron legal fees incurred in 2005.

Maintenance expense increased slightly in 2007 compared to 2006 primarily due to new transmission regulations, partially offset by lower maintenance cost for Ft. Churchill due to planned outages in 2006 and delayed outages for 2007.

The increase in Maintenance expense for 2006 compared to 2005 is primarily due to higher costs for scheduled maintenance and forced outages in 2006 at Ft. Churchill and Valmy; partially offset by a 2006 planned major outage at Tracy that was rescheduled to 2007.

Depreciation and amortization decreased in 2007 compared to 2006 due to retirement of plant assets as approved by the PUCN in SPPC's General Electric and Gas Rates Cases in June 2006. Also contributing to the decrease was a reduction in depreciation rates as ordered by the PUCN in SPPC's General Electric and Gas Rate Cases in June 2006.

Depreciation and amortization were lower in 2006 than 2005 due to the change in depreciation rates as ordered by PUCN in SPPC's General Electric and Gas Rate Case. For further information on SPPC's General and Electric Rate Case see Note 3, Regulatory Actions of the Notes to Financial Statements.

Interest charges on Long-Term Debt for the year ended December 31, 2007 decreased from 2006 primarily due to various re-financings of debt in 2006 at lower interest rates, redemption of debt, and the refinancing of $80 million Water Facilities Refunding Revenue Bonds from fixed to variable rate in April 2007. These re-financings and redemptions were partially offset by the issue of $300 million Series M notes in March 2006 and the issue of $325 million Series P notes in June 2007.

Interest charges on Long-Term Debt for the year ended December 31, 2006 increased from 2005 primarily due to interest on the $300 million Series M Notes issued in March 2006, partially offset by debt redemptions in 2006 of $188 million, and the refinancing of $268 million of tax exempt debt from fixed rate to variable in November 2006. See Note 6, Long-Term Debt of the Notes to Financial Statements for additional information regarding long-term debt.

SPPC's interest charges for energy suppliers for the year ended December 31, 2005 reflects the reversal of interest of $3.2 million resulting from the November 2005 settlement agreement between the Utilities and Enron. See Note 13, Commitments and Contingencies, of the Notes to Financial Statements, for more information regarding the Enron litigation.

Interest charges-other for the year ended December 31, 2007 increased compared to the same period in 2006 due to higher amortization costs related to new debt issues in 2006 and 2007. Interest charges-other for the year ended December 31, 2006 increased compared to the same period in 2005 primarily due to higher amortization of debt issuance costs related to new debt issuances. See Financing Transactions under Liquidity and Capital Resources later in this section.

Interest accrued on deferred energy costs for the year ended December 31, 2007 decreased compared to the same period in 2006 primarily due to lower deferred energy balances during 2007. Interest accrued on deferred energy costs for the year ended December 31, 2006 decreased compared to the same period in 2005 primarily due to lower deferred energy balances during 2006. See Note 3, Regulatory Actions of the Notes to Financial Statements for further discussion of deferred energy accounting issues.

Other income decreased for the year ended December 31, 2007, compared to the same period in 2006 due to the expiration of the amortization of gains associated with the disposition of property and lower interest income in 2007, offset by a refund of expenses. Other income increased for the year ended December 31, 2006, compared to the same period in 2005, primarily due to an increase in interest income associated with higher cash balances from the issuance of new debt in March 2006, as well as gains from the sale of property.

Other expense for the year ended December 31, 2007 was comparable to the same period in 2006. Other expense for the year ended December 31, 2006 increased compared to the same period in 2005, primarily due to a loss on the disposition of property, higher donations, assistance program expenses, and penalties.

## ANALYSIS OF CASH FLOWS

Cash flows decreased for the year ended December 31, 2007 compared to the same period in 2006 due to an increase in cash used by investing activities and a decrease in cash from operating activities, partially offset by an increase in cash from financing activities.

***Cash From Operating Activities.*** Cash from operating activities decreased for the year ended December 31, 2007 as compared to the same period in 2006 as a result of a decrease in cash from accounts receivable and an increase in payments for Pension and Other Post Retirement Benefits of $36.5 million offset by an increase in accrued interest related to the issuance of SPPC's 6.75% General and Refunding Mortgage Notes, Series P, a reduction in prepayments for energy in 2006 and the net settlement with Enron in 2006. The decrease in cash from accounts receivable is primarily due to $49.7 million affiliated accounts receivable related to tax sharing agreements which were outstanding at December 31, 2005 and settled in 2006 offset by increased customer payments.

***Cash Used By Investing Activities.*** Cash used by investing activities increased during the year ended December 31, 2007 compared to the same period in 2006 primarily due to construction costs associated with the expansion of the Tracy Generating Station and utility infrastructure to support growth.

***Cash From Financing Activities.*** Cash from financing activities increased during the year ended December 31, 2007 compared to the same period in 2006 primarily due to the issuance of $325 million of SPPC's 6.75% General and Refunding Mortgage Notes, Series P, a reduction in the redemption of debt and preferred stock and dividends paid to SPR from 2006.

SPPC's cash flows decreased slightly during the year ended December 31, 2006, when compared to the same period in 2005, as a result of an increase in cash used by investing activities offset by an increase in cash from operating and financing activities. Cash used by investing activities increased during the year ended December 31, 2006 as compared to the same period in 2005 primarily as a result of the expansion of the Tracy Generating Station. Cash from operating activities were higher for the year ended December 31, 2006 as compared to the same period in 2005 mainly due to the settlement of balances outstanding for tax sharing agreements, a reduction in prepayments for energy and increases in general and energy rates, offset by the settlement with Enron during the first quarter of 2006. Cash from financing activities increased during the year ended December 31, 2006 as compared to the same period in 2005 primarily as a result of a capital contribution from SPR of $75 million. Also contributing to the increase were debt offerings partially offset by redemption of debt and preferred stock. In 2006, SPPC paid dividends to SPR of approximately $17.9 million.

## LIQUIDITY AND CAPITAL RESOURCES

### Overall Liquidity

SPPC's primary source of operating cash flows is electric revenues, including the recovery of previously deferred energy costs. Significant uses of cash flows from operations include the purchase of electricity and natural gas, other operating expenses,

capital expenditures and the payment of interest on SPPC's outstanding indebtedness. Operating cash flows can be significantly influenced by factors such as weather, regulatory outcomes, and economic conditions.

Available Liquidity as of December 31, 2007 (in millions)

| | SPPC |
|---|---|
| Cash and Cash Equivalents | $ 23.8 |
| Balance available on Revolving Credit Facility | 329.5 |
| | $ 353.3 |

[1] As of February 22, 2008, SPPC had approximately $330.5 million available under its revolving credit facility.

In 2007, SPR contributed capital, using proceeds from its December 2007 common stock offering, to SPPC of approximately $65 million. SPPC used the proceeds to repay indebtedness under its revolving credit facility and for general corporate purposes. In January 2008, SPR contributed additional capital to SPPC of approximately $20 million for general corporate purposes.

In 2007, SPPC paid $14.2 million in dividends to SPR and an additional $5.3 million, declared in November 2007 was outstanding as of December 31, 2007. In January 2008, SPPC paid the remaining $5.3 million in dividends to SPR. In February 2008, SPPC declared a dividend to SPR for approximately $8.0 million.

SPPC anticipates that it will be able to meet short-term operating costs, such as fuel and purchased power costs, with internally generated funds, including the recovery of deferred energy and the use of its revolving credit facility. To manage liquidity needs as a result of seasonal peaks in fuel requirement, SPPC may use hedging activities. However, to fund long-term capital requirements, as discussed below, SPPC may meet such financial obligations with a combination of internally generated funds, the use of the revolving credit facility and the issuance of long-term debt, preferred securities, and/or capital contributions from SPR.

Continued improvement in the credit ratings of SPPC (see Credit Ratings below) has strengthened the liquidity position of the company by allowing for the resumption of normal payment terms with our counterparties and the elimination of cash collateral requirements. Existing collateral requirements with counterparties have been satisfied with letters of credit. The recent credit rating upgrades reduce the cost of borrowing under SPPC's revolving credit facility. In addition, the upgrades have the potential to provide SPPC better access to capital markets and to reduce the cost of issuing additional long-term debt. However, disruptions in the banking and capital markets not specifically related to SPPC may affect its ability to access funding sources or cause an increase in the return required by investors.

SPPC designs operating and capital budgets to control operating costs and capital expenditures. In addition to operating expenses, SPPC has continuing commitments for capital expenditures for construction, improvement and maintenance of facilities.

Detailed below are SPPC's Capital Structure, Capital Requirements, Contractual Obligations, recently completed Financing Transactions and Factors Affecting Liquidity, including our ability to obtain debt on favorable terms.

**Capital Structure**

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

| | 2007 | | 2006 | |
|---|---|---|---|---|
| Current Maturities of Long-Term Debt | $ 101,643 | 4.6% | $ 2,400 | 0.1% |
| Long-Term Debt | 1,084,550 | 49.6% | 1,070,858 | 54.7% |
| Common Equity | 1,001,840 | 45.8% | 884,737 | 45.2% |
| Total | $ 2,188,033 | 100% | $ 1,957,995 | 100% |

**Capital Requirements**

*Construction Expenditures*

SPPC's cash construction expenditures are expected to increase due to programs designed to meet electric load growth and reliability needs. Cash construction expenditures for the years ended 2007, 2006 and 2005 were approximately $393 million, $285 million and $113 million, respectively. SPPC's cash construction expenditures for 2008 are projected to be $270 million. SPPC's cash construction expenditures for 2008 through 2012 are projected to be $1.7 billion. To fund these capital projects SPPC may meet such financial obligations with a combination of internally generated funds, the use of its revolving credit facility and if necessary, the issuance of long-term debt and/or capital contributions from SPR.

*Contractual Obligations*

The table below provides SPPC's consolidated contractual obligations 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. Certain contracts contain variable factors which required SPPC to estimate the obligation depending on the final variable amount. Actual amounts could differ. The table does not include estimated construction expenditures described above, except for major capital projects for which SPPC has executed contracts by December 31, 2007. Additionally, at December 31, 2007, SPPC recorded a $4.4 million liability in accordance with FIN 48, all of which is classified as non-current. SPPC is unable to make a reasonably reliable estimate of the period of cash payments to relevant tax authorities; consequently, none of the FIN 48 liability is included in the contractual obligations table below (dollars in thousands):

| | Payment Due by Period | | | | | | |
|---|---|---|---|---|---|---|---|
| | 2008 | 2009 | 2010 | 2011 | 2012 | Thereafter | Total |
| Long-Term Debt Maturities | $ 101,643 | $ 600 | $ - | $ - | $ 100,000 | $ 973,250 | $1,175,493 |
| Long-Term Debt Interest Payments | 68,788 | 65,298 | 65,288 | 65,288 | 60,861 | 1,007,138 | 1,332,661 |
| Purchased Power | 152,428 | 123,975 | 167,257 | 190,799 | 203,765 | 3,488,879 | 4,327,103 |
| Coal and Natural Gas | 194,915 | 87,813 | 60,762 | 60,752 | 44,407 | 295,366 | 744,015 |
| Long-Term Service Agreements[(1)] | 3,106 | 5,325 | 5,325 | 5,325 | 5,325 | 61,770 | 86,176 |
| Capital Projects[(2)] | 6,028 | - | - | - | - | - | 6,028 |
| Operating Leases | 12,672 | 11,605 | 10,682 | 3,329 | 1,557 | 37,452 | 77,297 |
| Total Contractual Cash Obligations | $ 539,580 | $294,616 | $ 309,314 | $ 325,493 | $ 415,915 | $ 5,863,855 | $7,748,773 |

(1) Represents the long term service agreement for the Tracy Combined Cycle station expected to be operational in 2008.
(2) Tracy Combined Cycle Station agreement.

## Pension Plan Matters

SPR has a qualified pension plan that covers substantially all employees of SPR, NPC and SPPC. The annual net benefit cost for the plan is expected to decrease in 2008 to $25.1 million compared to the 2007 cost of $29.3 million. As of September 30, 2007, the measurement date, the plan was under funded on a FAS 158 pension benefit obligation basis. Refer to Note 11, Retirement Plan and Post-Retirement Benefits, of the Notes to Financial Statements. During 2007, SPR contributed a total of $54 million to meet their funding obligations under the plan. At the present time it is not expected that any additional funding will be required in 2008 to meet the minimum funding level requirements defined by the Pension Benefit Guaranty Corporation and ERISA.

## Financing Transactions

*6.75% General and Refunding Mortgage Notes, Series P*

On June 28, 2007, SPPC issued and sold $325 million of its 6.750% General and Refunding Mortgage Notes, Series P, due July 1, 2037. The Series P Notes were issued pursuant to a registration statement previously filed with the Securities and Exchange Commission. The net proceeds from the issuance were used to fund the purchase of the tendered Series A Notes (discussed below), repay amounts outstanding under SPPC's revolving credit facility, and for general corporate purposes.

*Tender Offer for General and Refunding Mortgage Notes, Series A*

On June 28, 2007, SPPC settled its cash tender offer, which commenced on June 15, 2007 and expired on June 22, 2007, for its 8.00% General and Refunding Mortgage Notes, Series A, due 2008. Those holders who tendered their notes by the expiration date were entitled to receive a purchase price of $1,022.10 per $1,000 principal amount of Series A Notes. Approximately $220.8 million of the $320 million Series A Notes outstanding were validly tendered and accepted by SPPC.

*Washoe County Water Facilities Refunding Revenue Bonds*

On April 27, 2007, on behalf of SPPC, Washoe County, Nevada (Washoe County) issued $80 million aggregate principal amount of its Water Facilities Refunding Revenue Bonds, Series 2007A and B, due March 1, 2036 (the "Water Bonds").

In connection with the issuance of the Water Bonds, SPPC entered into financing agreements with Washoe County, pursuant to which Washoe County loaned the proceeds from the sales of the Water Bonds to SPPC. SPPC's payment obligations under the financing agreements are secured by SPPC's General and Refunding Mortgage Notes, Series O.

The Water Bonds initial rates, as determined by auction on April 25, 2007, were 3.85%. The method of determining the interest rate on the Water Bonds may be converted from time to time so that such Bonds would thereafter bear interest at a daily, weekly, flexible, auction or term rate as designated.

The proceeds of the offerings were used to refund the $80 million aggregate principal amount of 5.00% Washoe County Water Facilities Revenue Bonds, Series 2001.

**Factors Affecting Liquidity**

*Financial Covenants*

SPPC's $350 million Second Amended and Restated Revolving Credit Agreement dated November 2005, and amended in April 2006, contains two financial maintenance covenants. The first requires that SPPC maintain a ratio of consolidated indebtedness to consolidated capital, determined as of the last day of each fiscal quarter, not to exceed 0.68 to 1. The second requires that SPPC maintain a ratio of consolidated cash flow to consolidated interest expense, determined as of the last day of each fiscal quarter for the period of four consecutive fiscal quarters, not to be less than 2.0 to 1. As of December 31, 2007, SPPC was in compliance with these covenants.

*Ability to Issue Debt*

Certain factors impact SPPC's ability to issue debt:

1. Financing Authority from the PUCN: On June 22, 2007, SPPC received PUCN authorization to enter into financings of $1.72 billion through 2009. Of this total, $300 million is contingent upon the PUCN's approval of the Ely Energy Center in 2008. The remaining authority, $1.42 billion, includes authority for the revolving credit facility, and authority to issue new debt and to refinance existing debt. As of December 31, 2007, SPPC used $350 million of the $1.42 billion authority for the revolving credit facility, and $325 million for the issuance of the 6.75% General and Refunding Notes, Series P (see Financing Transactions, above). As such, approximately $745 million of the authority remains.

2. Financial Covenants in its and SPR's financing agreements. The terms of certain SPR debt prohibit NPC and SPPC from incurring additional indebtedness unless certain conditions have been met. See SPR's Ability to Issue Debt. In addition to the SPR debt, the terms of SPPC's Series H General and Refunding Mortgage Notes, which mature in 2012, (collectively "SPPC's Debt") restrict SPPC from incurring any additional indebtedness unless certain covenants are satisfied. As of December 31, 2007, the financial covenants under SPPC's debt allow for greater borrowings than SPR's cap on additional consolidated indebtedness; therefore, SPPC is limited by SPR's cap on additional consolidated indebtedness of $1.1 billion. If SPPC's Series H General and Refunding Mortgage Notes are upgraded to investment grade by S&P, the restrictions imposed by those Notes will be suspended and will no longer be in effect so long as the Series of H Notes remain investment grade by both Moody's and S&P.

Since SPR's debt covenant limitations are calculated on a consolidated basis, SPR's debt covenant limitations may allow for higher or lower borrowing than $1.1 billion, depending on the Utilities' combined outstanding balances under their revolving credit facilities at the time of the covenant calculations.

*Ability to Issue General and Refunding Mortgage Securities*

To the extent that SPPC has the ability to issue debt under the most restrictive covenants in its financing agreements and has financing authority to do so from the PUCN, SPPC's ability to issue secured debt is still limited by the amount of bondable property or retired bonds that can be used to issue debt under SPPC's General and Refunding Mortgage Indenture ("Indenture").

The Indenture creates a lien on substantially all of SPPC's properties in Nevada and California. As of December 31, 2007, $1.5 billion of SPPC's General and Refunding Mortgage Securities were outstanding. SPPC had the capacity to issue $348 million of General and Refunding Mortgage Securities as of December 31, 2007. That amount is determined on the basis of:

1. 70% of net utility property additions;
2. the principal amount of retired General and Refunding Mortgage Securities; and/or
3. the principal amount of first mortgage bonds retired after October 2001.

Property Additions include plant in service and specific assets in construction work in progress. The amount of bond capacity listed above does not include eligible property in construction work in progress.

*Credit Ratings*

SPPC is rated by four Nationally Recognized Statistical Rating Organizations: DBRS, Fitch, Moody's and S&P. As of February 22, 2008, the ratings are as follows:

| | | Rating Agency | | | |
|---|---|---|---|---|---|
| | | DBRS | Fitch | Moody's | S&P |
| SPPC | Sr. Secured Debt | BBB (low)* | BBB-* | Baa3* | BB+ |

* Ratings are investment grade

Three of the four rating agencies currently rate SPPC's senior secured debt investment grade. Moody's and DBRS's rating outlook for SPPC is Stable. In June 2007, S&P and Fitch revised their outlook on SPPC to Positive from Stable.

A security rating is not a recommendation to buy, sell or hold securities. Security ratings are subject to revision and withdrawal at any time by the assigning rating organization, and each rating should be evaluated independently of any other rating.

*Credit Ratings of Bond Insurers*

Recent sub-prime mortgage issues have adversely affected the overall financial markets, generally resulting in increased interest rates, reduced access to the capital markets, and actual or potential downgrades of bond insurers, among other negative matters. The interest rates on certain issues of SPPC's, Variable Rate Notes of approximately $348.3 million, as presented in its Consolidated Statements of Capitalization are periodically reset through auction processes. These securities are supported by bond insurance policies provided by either Ambac, FGIC, or MBIA (collectively, the "Insurers"), and the interest rates on those securities are directly affected by the rating of the bond insurer due to, among other things, the impact that such ratings have on the success or failure of the auction process. The uncertainty with the Insurers' credit quality has had an impact on SPPC's interest costs for these specific securities in the fourth quarter of 2007, although not significant. However, if the credit quality of the Insurers continues to deteriorate, SPPC could experience higher interest costs for these securities.

*Energy Supplier Matters*

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

Under these contracts, a material adverse change in SPPC would allow the counterparty to request adequate financial assurance, which, if not provided within three business days, could cause a default. A default must be declared within 30 days of the event giving rise to the default becoming known. A default will result in a termination payment equal to the present value of the net gains and losses for the entire remaining term of all contracts between the parties aggregated to a single liquidated amount due within three business days following the date the notice of termination is received. The mark-to-market value, which is substantially based on quoted market prices, can be used to roughly approximate the termination payment and benefit at any point in time. The net mark-to-market value as of December 31, 2007 for all suppliers continuing to provide power under a WSPP agreement would approximate a $1.1 million payment by SPPC. These contracts qualify for the normal purchases scope exception of SFAS No. 133, and as such, are not required to be marked to market on the balance sheet. Refer to Note 9, Derivatives and Hedging Activities, of the Notes to Financial Statements for further discussion.

*Gas Supplier Matters*

With respect to the purchase and sale of natural gas, SPPC uses several types of standard industry contracts. The natural gas contract terms and conditions are more varied than the electric contracts. Consequently, some of the contracts contain language similar to that found in the WSPP agreement and other agreements have unique provisions dealing with material adverse changes. Because of creditworthiness concerns, most contracts and confirmations for natural gas purchases have been modified or separate agreements have been made to either shorten the normal payment due date or require payment in advance of delivery. At the present time, no counter-parties require payment in advance of delivery.

Gas transmission service is secured under FERC Tariffs or custom agreements. These service contracts and Tariffs require the user establish and maintain creditworthiness to obtain service or otherwise post cash or a letter of credit to be able to receive service. Service contracts are subject to FERC approved tariffs, which, under certain circumstances, require the Utility to provide collateral to continue receiving service.

*Cross Default Provisions*

SPPC's financing agreements do not contain any cross-default provisions that would result in an event of default by SPPC upon an event of default by SPR or NPC under any of their respective financing agreements. Certain financing agreements of SPPC provide for an event of default if there is a failure under other financing agreements of SPPC to meet payment terms or to observe other covenants that would result in an acceleration of payments due. Most of these default provisions (other than ones relating to a failure to pay such other indebtedness when due) provide for a cure period of 30-60 days from the occurrence of a specified event during which time SPPC may rectify or correct the situation before it becomes an event of default.

## REGULATORY PROCEEDINGS (UTILITIES)

SPR is a "holding company" under the Public Utility Holding Company Act of 2005 (PUHCA 2005). As a result, SPR and all of its subsidiaries (whether or not engaged in any energy related business) are required to maintain books, accounts and other records in accordance with FERC regulations and to make them available to the FERC, the PUCN and CPUC. In addition, the PUCN, CPUC, or the FERC have the authority to review allocations of costs of non-power goods and administrative services among SPR and its subsidiaries. The FERC has the authority generally to require that rates subject to its jurisdiction be just and reasonable and in this context would continue to be able to, among other things, review transactions between SPR, NPC and/or SPPC and/or any other affiliated company.

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

Under federal law, the Utilities 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 Utilities are required to file annual electric and gas Deferred Energy Accounting Adjustment (DEAA) cases on March 1 as mandated by the 2007 Nevada Legislature, quarterly Base Tariff Energy Rate (BTER) Updates for the Utilities' electric and gas departments, and triennial GRCs in Nevada. A DEAA case is filed to recover/refund any under/over collection of prior energy costs and the BTER Updates recover current energy costs. As of December 31, 2007, NPC's and SPPC's balance sheets included approximately $281.0 million and credit of $28.9 million, respectively, of deferred energy costs of which $324.7 million and $12.0 million had been previously approved for collection over various periods. The remaining amounts will be requested in future DEAA filings. Refer to Note 1, Summary of Significant Accounting Policies, of the Notes to Financial Statements. A GRC filing is to set rates to recover operation and maintenance expenses, depreciation, taxes and provide a return on invested capital.

Rate case applications filed in 2006 and 2007, as well as other regulatory matters such as, the Utilities' IRPs and subsequent amendments, other Nevada matters, California matters and FERC matters, are discussed in more detail in Note 3, Regulatory Actions, of the Notes to Financial Statements.

## ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

### Interest Rate Risk

As of December 31, 2007, 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. 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, 2007**

| | Expected Maturity Date | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 2008 | 2009 | 2010 | 2011 | 2012 | Thereafter | Total | Fair Value |
| **Long-term Debt** | | | | | | | | |
| **SPR** | | | | | | | | |
| Fixed Rate | $ - | $ - | $ - | $ - | $ 63,670 | $ 460,539 | $ 524,209 | $ 544,587 |
| Average Interest Rate | - | - | - | - | 7.80% | 7.77% | 7.77% | |
| **NPC** | | | | | | | | |
| Fixed Rate | $ 12 | $ - | $ - | $ 364,000 | $ 130,000 | $1,786,579 | $2,280,591 | $2,354,641 |
| Average Interest Rate | 8.17% | - | - | 8.14% | 6.50% | 6.34% | 6.64% | |
| Variable Rate | $ - | $ 15,000 | $ - | $ - | $ - | $ 192,500 | $ 207,500 | $ 207,500 |
| Average Interest Rate | - | 4.33% | - | - | - | 4.05% | 4.07% | |
| **SPPC** | | | | | | | | |
| Fixed Rate | $101,643 | $ 600 | $ - | $ - | $100,000 | $ 625,000 | $ 827,243 | $ 842,654 |
| Average Interest Rate | 7.96% | 6.40% | - | - | 6.25% | 6.39% | 6.57% | |
| Variable Rate | $ - | $ - | $ - | $ - | $ - | $ 348,250 | $ 348,250 | $ 348,250 |
| Average Interest Rate | - | - | - | - | - | 3.86% | 3.86% | |
| **Total Debt** | $101,655 | $ 15,600 | $ - | $ 364,000 | $ 293,670 | $ 3,412,868 | $4,187,793 | $4,297,632 |

**December 31, 2006**

| | Expected Maturity Date | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| | 2007 | 2008 | 2009 | 2010 | 2011 | Thereafter | Total | Fair Value |
| **Long-term Debt** | | | | | | | | |
| **SPR** | | | | | | | | |
| Fixed Rate | $ - | $ - | $ - | $ - | $ - | $ 549,209 | $ 549,209 | $ 568,541 |
| Average Interest Rate | - | - | - | - | - | 7.75% | 7.75% | |
| **NPC** | | | | | | | | |
| Fixed Rate | $ 15 | $ 15 | $ - | $ - | $ 364,000 | $1,776,835 | $2,140,865 | $2,246,234 |
| Average Interest Rate | 8.17% | 8.17% | - | - | 8.14% | 6.58% | 6.85% | |
| Variable Rate | $ - | $ - | $ 15,000 | $ - | $ - | $ 192,500 | $ 207,500 | $ 207,500 |
| Average Interest Rate | - | - | 3.63% | - | - | 3.57% | 3.57% | |
| **SPPC** | | | | | | | | |
| Fixed Rate | $ 2,400 | $322,400 | $ 80,600 | $ - | $ - | $ 400,000 | $ 805,400 | $ 819,744 |
| Average Interest Rate | 6.40% | 7.99% | 5.01% | - | - | 6.06% | 6.73% | |
| Variable Rate | $ - | $ - | $ - | $ - | $ - | $ 268,250 | $ 268,250 | $ 268,250 |
| Average Interest Rate | - | - | - | - | - | 3.62% | 3.62% | |
| **Total Debt** | $ 2,415 | $322,415 | $ 95,600 | $ - | $ 364,000 | $ 3,186,794 | $3,971,224 | $4,110,269 |

### Commodity Price Risk

Commodity price increases due to changes in market conditions are recovered through the deferred energy mechanism. Although the Utilities actively manage energy commodity (electric, natural gas, coal and oil) price risk through their procurement strategies, the ability to recover commodity price changes through future rates substantially mitigates commodity price risk. However, the Utilities are subject to cash flow risk due to changes in the value of their open positions and are subject to regulatory risk because

the PUCN may disallow recovery for any costs that it considers imprudently incurred. The Utilities mitigate both risk associated with its open positions and regulatory risk through prudent energy supply practices which include the use of long-term fuel supply agreements, long-term purchase power agreements and derivative instruments such as forwards, options and swaps to meet the anticipated fuel and power requirements. See Energy Supply in Item 7, Management's Discussion and Analysis of Financial Condition and Results of Operations, for a discussion of the Utilities' purchased power procurement strategies.

**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 $4.9 million as of December 31, 2007, which decreased significantly from December 31, 2006 as a result of two large plant tolling agreements that were in place at December 31, 2006 expiring during 2007. 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.

Pursuant to rules and tariffs governing the extension of electric service to residential and commercial real estate developments the Utilities' have made certain electric system investments which may be affected by the current real estate and credit markets. The Utilities are exposed to credit risk in the event that developers are unable to satisfy their obligations to complete these projects. At the present time, the Utilities' credit risk related to the recovery of these investments is not believed to be significant.

## ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets and statements of capitalization of Sierra Pacific Resources and subsidiaries (the "Company") as of December 31, 2007 and 2006, and the related consolidated income statements and statements of comprehensive income, common stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2007. Our audits also included the financial statement schedules listed in the Index at Item 15(a) (2). These financial statements and financial statement schedules are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedules based on our audits.

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

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Sierra Pacific Resources and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, on January 1, 2006, the Company adopted the provisions of Statement of Financial Accounting Standards No. 123(R).

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 27, 2008 expressed an unqualified opinion on the Company's internal control over financial reporting.

DELOITTE & TOUCHE LLP

Reno, Nevada
February 27, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Shareholder of
Nevada Power Company
Las Vegas, Nevada

We have audited the accompanying consolidated balance sheets and statements of capitalization of Nevada Power Company and subsidiaries (the "Company") as of December 31, 2007 and 2006, and the related consolidated income statements, statements of comprehensive income, common shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2007. Our audits also included the financial statement schedule listed in the Index at Item 15(a) (2). These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Nevada Power Company and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

DELOITTE & TOUCHE LLP

Reno, Nevada
February 27, 2008

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the accompanying consolidated balance sheets and statements of capitalization of Sierra Pacific Power Company and subsidiaries (the "Company") as of December 31, 2007 and 2006, and the related consolidated income statements and statements of comprehensive income, common shareholder's equity, and cash flows for each of the three years in the period ended December 31, 2007. Our audits also included the financial statement schedule listed in the Index at Item 15(a) (2). These financial statements and financial statement schedule are the responsibility of the Company's management. Our responsibility is to express an opinion on the financial statements and financial statement schedule based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. The Company is not required to have, nor were we engaged to perform, an audit of its internal control over financial reporting. Our audits included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company's internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the financial position of Sierra Pacific Power Company and subsidiaries as of December 31, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly, in all material respects, the information set forth therein.

DELOITTE & TOUCHE LLP

Reno, Nevada
February 27, 2008

**SIERRA PACIFIC RESOURCES**
**CONSOLIDATED BALANCE SHEETS**
**(Dollars in Thousands)**

| | December 31, 2007 | December 31, 2006 |
|---|---|---|
| **ASSETS** | | |
| Utility Plant at Original Cost: | | |
| Plant in service | $ 8,468,711 | $ 7,954,337 |
| Less accumulated provision for depreciation | 2,526,379 | 2,333,357 |
| | 5,942,332 | 5,620,980 |
| Construction work-in-progress | 1,068,666 | 466,018 |
| | 7,010,998 | 6,086,998 |
| Investments and other property, net (Note 4) | 31,061 | 34,325 |
| Current Assets: | | |
| Cash and cash equivalents | 129,140 | 115,709 |
| Accounts receivable less allowance for uncollectible accounts: 2007-$36,061; 2006-$39,566 | 434,359 | 415,082 |
| Deferred energy costs - electric (Note 1) | 75,948 | 168,260 |
| Materials, supplies and fuel, at average cost | 117,483 | 103,757 |
| Risk management assets (Note 9) | 22,286 | 27,305 |
| Deferred income taxes (Note 10) | 43,295 | 55,546 |
| Deposits and prepayments for energy | 1,142 | 15,968 |
| Other | 44,767 | 31,580 |
| | 868,420 | 933,207 |
| Deferred Charges and Other Assets: | | |
| Deferred energy costs - electric (Note 1) | 205,030 | 382,286 |
| Regulatory tax asset (Note 10) | 267,848 | 263,170 |
| Regulatory asset for pension plans (Note 11) | 133,984 | 223,218 |
| Other regulatory assets (Note 1) | 758,287 | 668,624 |
| Risk management assets (Note 9) | 12,429 | 7,586 |
| Risk management regulatory assets - net (Note 9) | 26,067 | 122,911 |
| Unamortized debt issuance costs | 65,218 | 67,106 |
| Other | 85,408 | 42,645 |
| | 1,554,271 | 1,777,546 |
| **TOTAL ASSETS** | $ 9,464,750 | $ 8,832,076 |
| **CAPITALIZATION AND LIABILITIES** | | |
| Capitalization: | | |
| Common shareholders' equity | $ 2,996,575 | $ 2,622,297 |
| Long-term debt | 4,137,864 | 4,001,542 |
| | 7,134,439 | 6,623,839 |
| Current Liabilities: | | |
| Current maturities of long-term debt | 110,285 | 8,348 |
| Accounts payable | 357,867 | 282,463 |
| Accrued interest | 69,485 | 56,426 |
| Accrued salaries and benefits | 35,020 | 33,146 |
| Current income taxes payable (Note 10) | 3,544 | 5,914 |
| Risk management liabilities (Note 9) | 39,509 | 123,065 |
| Accrued taxes | 8,336 | 6,290 |
| Deferred energy costs-electric (Note 1) | 17,573 | - |
| Deferred energy costs - gas (Note 1) | 11,369 | 112 |
| Other current liabilities | 65,991 | 60,310 |
| | 718,979 | 576,074 |
| Commitments and Contingencies (Note 13) | | |
| Deferred Credits and Other Liabilities: | | |
| Deferred income taxes (Note 10) | 852,630 | 791,428 |
| Deferred investment tax credit | 28,895 | 35,218 |
| Regulatory tax liability (Note 10) | 28,445 | 34,075 |
| Customer advances for construction | 100,125 | 91,895 |
| Accrued retirement benefits | 77,525 | 226,420 |
| Risk Management Liabilities (Note 9) | 7,369 | 10,746 |
| Regulatory liabilities | 304,026 | 301,903 |
| Other | 212,317 | 140,478 |
| | 1,611,332 | 1,632,163 |
| **TOTAL CAPITALIZATION AND LIABILITIES** | $ 9,464,750 | $ 8,832,076 |

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

**SIERRA PACIFIC RESOURCES**
**CONSOLIDATED INCOME STATEMENTS**
**(Dollars in Thousands, Except Per Share Amounts)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2007** | **2006** | **2005** |
| **OPERATING REVENUES:** | | | |
| Electric | $ 3,395,487 | $ 3,144,243 | $ 2,850,694 |
| Gas | 205,430 | 210,068 | 178,270 |
| Other | 43 | 1,639 | 1,278 |
| | 3,600,960 | 3,355,950 | 3,030,242 |
| **OPERATING EXPENSES:** | | | |
| Operation: | | | |
| Purchased power | 1,036,905 | 1,109,440 | 1,315,986 |
| Fuel for power generation | 837,355 | 800,585 | 510,736 |
| Gas purchased for resale | 150,879 | 160,739 | 140,850 |
| Deferred energy costs disallowed | 14,171 | - | - |
| Deferral of energy costs - electric - net | 297,039 | 139,365 | (37,558) |
| Deferral of energy costs - gas - net | 10,763 | 6,947 | (749) |
| Reinstatement of deferred energy (Note 3) | - | (178,825) | - |
| Other | 379,446 | 367,198 | 363,802 |
| Maintenance | 99,035 | 93,172 | 78,730 |
| Depreciation and amortization | 235,532 | 228,875 | 214,662 |
| Taxes: | | | |
| Income taxes (Note 10) | 75,155 | 91,571 | 39,185 |
| Other than income | 50,113 | 48,086 | 45,920 |
| | 3,186,393 | 2,867,153 | 2,671,564 |
| **OPERATING INCOME** | 414,567 | 488,797 | 358,678 |
| **OTHER INCOME (EXPENSE):** | | | |
| Allowance for other funds used during construction | 31,809 | 18,226 | 20,322 |
| Interest accrued on deferred energy | 15,078 | 27,898 | 27,442 |
| Early debt conversion fees | - | - | (54,000) |
| Carrying charge for Lenzie (Note 1) | 16,080 | 33,440 | - |
| Gain on sale of investment | 1,369 | 62,927 | - |
| Reinstated interest on deferred energy (Note 3) | 11,076 | - | - |
| Other income | 24,580 | 37,123 | 41,200 |
| Other expense | (25,076) | (23,497) | (18,645) |
| Income taxes (Note 10) | (12,400) | (54,034) | (3,933) |
| | 62,516 | 102,083 | 12,386 |
| Total Income Before Interest Charges | 477,083 | 590,880 | 371,064 |
| **INTEREST CHARGES:** | | | |
| Long-term debt | 273,985 | 294,488 | 302,668 |
| Interest for Energy Suppliers (Note 13) | - | - | (17,221) |
| Other | 31,770 | 33,719 | 24,171 |
| Allowance for borrowed funds used during construction | (25,967) | (17,119) | (24,691) |
| | 279,788 | 311,088 | 284,927 |
| Preferred stock dividend requirements of subsidiary and premium on redemption | - | 2,341 | 3,900 |
| **NET INCOME APPLICABLE TO COMMON STOCK** | $ 197,295 | $ 277,451 | $ 82,237 |
| Amount per share basic and diluted - (Note 15) | | | |
| Net Income applicable to common stock | $ 0.89 | $ 1.33 | $ 0.44 |
| Weighted Average Shares of Common Stock Outstanding - basic | 222,180,440 | 208,531,134 | 185,548,314 |
| Weighted Average Shares of Common Stock Outstanding - diluted | 222,554,024 | 209,020,896 | 185,932,504 |

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

**SIERRA PACIFIC RESOURCES**
**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)**
**(Dollars in Thousands)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2007** | **2006** | **2005** |
| **NET INCOME APPLICABLE TO COMMON STOCK** | $ 197,295 | $ 277,451 | $ 82,237 |
| **OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX:** | | | |
| Change in market value of risk management assets and liabilities as of December 31 (Net of taxes of $1,155 in 2005) | - | - | (2,146) |
| Minimum pension liability adjustment (net of taxes of ($1,132) and $1,569 in 2006 and 2005, respectively) | - | 2,106 | (4,311) |
| Change in SFAS 158 liability and amortization (net of taxes of $1,250) | (2,323) | - | - |
| **OTHER COMPREHENSIVE INCOME (LOSS)** | (2,323) | 2,106 | (6,457) |
| **COMPREHENSIVE INCOME** | $ 194,972 | $ 279,557 | $ 75,780 |

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

**SIERRA PACIFIC RESOURCES**
**CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDERS' EQUITY**
**(Dollars in Thousands)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2007** | **2006** | **2005** |
| Common Stock: | | | |
| Balance at Beginning of Year | $ 221,030 | $ 200,792 | $ 117,469 |
| Stock issuance/exchange, CSIP, DRP, ESPP and other | 12,709 | 20,238 | 83,323 |
| Balance at end of year | 233,739 | 221,030 | 200,792 |
| Other Paid-In Capital: | | | |
| Balance at Beginning of Year | 2,483,244 | 2,220,896 | 1,818,453 |
| Premium on issuance/exchange of common stock | 190,808 | 260,600 | 405,767 |
| Common Stock issuance costs | (298) | (857) | (6,486) |
| Revaluation of investment | - | - | 119 |
| Stock purchase and dividend reinvestment | 504 | - | - |
| Tax Benefit from stock option exercises | 891 | - | - |
| CSIP, DRP, ESPP and other | 9,696 | 2,605 | 3,043 |
| Balance at End of Year | 2,684,845 | 2,483,244 | 2,220,896 |
| Retained Earnings (Deficit): | | | |
| Balance at Beginning of Year | (78,432) | (355,883) | (438,112) |
| FIN 48 Adjustment to beginning balance | 487 | - | - |
| Net Income applicable to Common Stock | 197,295 | 277,451 | 82,237 |
| Common stock dividends declared, net of adjustments | (35,491) | - | (8) |
| Balance at End of Year | 83,859 | (78,432) | (355,883) |
| Accumulated Other Comprehensive Income (Loss): | | | |
| Balance at Beginning of Year | (3,545) | (5,651) | 806 |
| Change in market value of risk management assets and liabilities as of December 31 (Net of taxes of $1,155 in 2005 ) | - | - | (2,146) |
| Minimum pension liability adjustment (net of taxes of ($1,132) and $1,569 in 2006 and 2005, respectively) | - | 2,106 | (4,311) |
| Change in SFAS 158 liability and amortization (net of taxes of $1,250) | (2,323) | - | - |
| Balance at End of Year | (5,868) | (3,545) | (5,651) |
| Total Common Shareholder's Equity at End of Year | $ 2,996,575 | $ 2,622,297 | $ 2,060,154 |

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

**SIERRA PACIFIC RESOURCES**
**CONSOLIDATED STATEMENTS OF CASH FLOWS**
**(Dollars in Thousands)**

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2007** | **2006** | **2005** |
| **CASH FLOWS FROM OPERATING ACTIVITIES:** | | | |
| Net Income applicable to common stock | $ 197,295 | $ 277,451 | $ 82,237 |
| Adjustments to reconcile net income to net cash from operating activities: | | | |
| Depreciation and amortization | 235,532 | 228,875 | 214,662 |
| Deferred taxes and deferred investment tax credit | 79,337 | 136,026 | 41,609 |
| AFUDC | (31,809) | (18,226) | (45,013) |
| Amortization of deferred energy costs - electric | 246,907 | 166,821 | 188,221 |
| Amortization of deferred energy costs - gas | 701 | 6,234 | 1,446 |
| Deferral of energy costs - electric | 51,311 | (54,737) | (241,103) |
| Deferral of energy costs - gas | 10,668 | 436 | (2,519) |
| Deferral of energy costs - terminated suppliers | - | 8,741 | 218,040 |
| Reinstatement of deferred energy | - | (178,825) | - |
| Carrying charge on Lenzie plant | (16,080) | (33,440) | - |
| Reinstated interest on deferred energy | (11,076) | - | - |
| Gain on sale of investment | (1,369) | (62,927) | - |
| Other, net | 23,679 | 24,650 | (219) |
| Changes in certain assets and liabilities: | | | |
| Accounts receivable | (19,276) | (43,214) | (92,452) |
| Materials, supplies and fuel | (13,725) | (15,312) | (12,251) |
| Other current assets | 1,639 | 24,050 | 20,663 |
| Accounts payable | 42,958 | (2,739) | 55,985 |
| Payment to terminating supplier | - | (65,368) | - |
| Proceeds from claim on terminating supplier | - | 41,365 | - |
| Accrued retirement benefits | (75,820) | (3,393) | 9,338 |
| Other current liabilities | 22,475 | 2,356 | (162,416) |
| Risk Management assets and liabilities | 10,088 | (5,950) | (6,685) |
| Other assets | 2,498 | (10,122) | (9,950) |
| Other liabilities | (2,112) | 6,690 | (24,997) |
| Net Cash from by Operating Activities | 753,821 | 429,442 | 234,596 |
| **CASH FLOWS USED BY INVESTING ACTIVITIES:** | | | |
| Additions to utility plant | (1,197,326) | (986,019) | (686,394) |
| AFUDC | 31,809 | 18,226 | 45,013 |
| Customer advances for construction | 8,230 | 17,348 | 27,358 |
| Contributions in aid of construction | 32,165 | 38,792 | 23,351 |
| Proceeds from sale of investment | 1,935 | 99,730 | - |
| Investments and other property - net | 2,810 | 8,423 | 10,200 |
| Net Cash used by Investing Activities | (1,120,377) | (803,500) | (580,472) |
| **CASH FLOWS FROM FINANCING ACTIVITIES:** | | | |
| Change in restricted cash and investments | - | 3,612 | 23,711 |
| Proceeds from issuance of long-term debt | 1,246,383 | 2,491,883 | 370,211 |
| Retirement of long-term debt | (1,044,866) | (2,407,745) | (373,938) |
| Redemption of preferred stock | - | (51,366) | - |
| Sale of Common Stock | 213,339 | 281,554 | 235,618 |
| Proceeds from exercise of stock option | 548 | 1,040 | 590 |
| Dividends paid | (35,417) | (1,945) | (3,911) |
| Net Cash from Financing Activities | 379,987 | 317,033 | 252,281 |
| **Net Increase (Decrease) in Cash and Cash Equivalents** | 13,431 | (57,025) | (93,595) |
| Beginning Balance in Cash and Cash Equivalents | 115,709 | 172,734 | 266,330 |
| Ending Balance in Cash and Cash Equivalents | $ 129,140 | $ 115,709 | $ 172,735 |
| **Supplemental Disclosures of Cash Flow Information:** | | | |
| Cash paid during period for: | | | |
| Interest | $ 267,082 | $ 338,665 | $ 330,889 |
| Income taxes | $ 9,727 | $ 4,726 | $ - |
| **Noncash Activities:** | | | |
| Exchange of Convertible Debt for SPR Common Stock | $ - | $ - | $ 248,168 |

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

**SIERRA PACIFIC RESOURCES**
**CONSOLIDATED STATEMENTS OF CAPITALIZATION**
**(Dollars in Thousands, Except Per Share Amounts)**

| | December 31, 2007 | December 31, 2006 |
|---|---|---|
| **Common Shareholders' Equity:** | | |
| Common stock, $1.00 par value, authorized 350 million; issued and outstanding 2007: 233,739,000 shares; issued and outstanding 2006: 221,030,000 shares issued and outstanding | $ 233,739 | $ 221,030 |
| Other paid-in capital | 2,684,845 | 2,483,244 |
| Retained Earnings (Deficit) | 83,859 | (78,432) |
| Accumulated other comprehensive loss | (5,868) | (3,545) |
| Total Common Shareholders' Equity | 2,996,575 | 2,622,297 |
| **Long-Term Debt:** | | |
| **Secured Debt** | | |
| Debt Secured by General and Refunding Mortgage Indenture | | |
| Nevada Power Company | | |
| 8.25% NPC Series A due 2011 | 350,000 | 350,000 |
| 6.50% NPC Series I due 2012 | 130,000 | 130,000 |
| 9.00% NPC Series G due 2013 | 17,244 | 227,500 |
| 5.875% NPC Series L due 2015 | 250,000 | 250,000 |
| 5.95% NPC Series M due 2016 | 210,000 | 210,000 |
| 6.65% NPC Series N due 2036 | 370,000 | 370,000 |
| 6.00% NPC Series O due 2018 | 325,000 | 325,000 |
| 6.75% NPC Series R due 2037 | 350,000 | - |
| Subtotal | 2,002,244 | 1,862,500 |
| Sierra Pacific Power Company | | |
| 8.00% SPPC Series A due 2008 | 99,243 | 320,000 |
| 6.25% SPPC Series H due 2012 | 100,000 | 100,000 |
| 6.00% SPPC Series M due 2016 | 300,000 | 300,000 |
| 5.00% SPPC Series 2001 due 2036 | - | 80,000 |
| 6.75% SPPC Series P due 2037 | 325,000 | - |
| Subtotal | 824,243 | 800,000 |
| Variable Rate Notes | | |
| Nevada Power Company | | |
| NPC PCRB Series 2000B due 2009 | 15,000 | 15,000 |
| NPC IDRB Series 2000A due 2020 | 100,000 | 100,000 |
| NPC PCRB Series 2006 due 2036 | 39,500 | 39,500 |
| NPC PCRB Series 2006A due 2032 | 40,000 | 40,000 |
| NPC PCRB Series 2006B due 2039 | 13,000 | 13,000 |
| Subtotal | 207,500 | 207,500 |
| Sierra Pacific Power Company | | |
| SPPC PCRB Series 2006 due 2029 | 49,750 | 49,750 |
| SPPC PCRB Series 2006A due 2031 | 58,700 | 58,700 |
| SPPC PCRB Series 2006B due 2036 | 75,000 | 75,000 |
| SPPC PCRB Series 2006C due 2036 | 84,800 | 84,800 |
| SPPC WFRB Series 2007A due 2036 | 40,000 | - |
| SPPC WFRB Series 2007B due 2036 | 40,000 | - |
| Subtotal | 348,250 | 268,250 |
| **Unsecured Debt** | | |
| Revenue Bonds | | |
| Nevada Power Company | | |
| 5.30% NPC Series 1995D due 2011 | 14,000 | 14,000 |
| 5.45% NPC Series 1995D due 2023 | 6,300 | 6,300 |
| 5.50% NPC Series 1995C due 2030 | 44,000 | 44,000 |
| 5.60% NPC Series 1995A due 2030 | 76,750 | 76,750 |
| 5.90% NPC Series 1995B due 2030 | 85,000 | 85,000 |
| 5.90% NPC Series 1997A due 2032 | 52,285 | 52,285 |
| Subtotal | 278,335 | 278,335 |

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

(Continued)

**SIERRA PACIFIC RESOURCES**
**CONSOLIDATED STATEMENTS OF CAPITALIZATION**
**(Dollars in Thousands)**

| | December 31, | |
|---|---|---|
| | **2007** | **2006** |
| Other Notes | | |
| Sierra Pacific Resources | | |
| 7.803% SPR Senior Notes due 2012 | 63,670 | 74,170 |
| 8.625% SPR Notes due 2014 | 250,039 | 250,039 |
| 6.75% SPR Senior Notes due 2017 | 210,500 | 225,000 |
| Subtotal, excluding current portion | 524,209 | 549,209 |
| Unamortized bond premium and discount, net | (1,068) | (11,813) |
| Obligations under capital leases | 61,424 | 50,479 |
| Current maturities and sinking fund requirements | (110,285) | (8,348) |
| Other, excluding current portion | 3,012 | 5,430 |
| Total Long-Term Debt | 4,137,864 | 4,001,542 |
| **TOTAL CAPITALIZATION** | $ 7,134,439 | $ 6,623,839 |

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

(Concluded)

**NEVADA POWER COMPANY**
**CONSOLIDATED BALANCE SHEETS**
**(Dollars in Thousands)**

| | December 31, 2007 | December 31, 2006 |
|---|---|---|
| **ASSETS** | | |
| Utility Plant at Original Cost: | | |
| Plant in service | $ 5,571,492 | $ 5,187,665 |
| Less accumulated provision for depreciation | 1,407,334 | 1,276,192 |
| | 4,164,158 | 3,911,473 |
| Construction work-in-progress | 576,127 | 238,518 |
| | 4,740,285 | 4,149,991 |
| Investments and other property, net (Note 4) | 19,544 | 22,176 |
| Current Assets: | | |
| Cash and cash equivalents | 37,001 | 36,633 |
| Accounts receivable less allowance for uncollectible accounts: 2007-$30,392, 2006-$32,834 | 274,242 | 244,623 |
| Deferred energy costs - electric (Note 1) | 75,948 | 129,304 |
| Materials, supplies and fuel, at average cost | 68,671 | 60,754 |
| Risk management assets (Note 9) | 16,078 | 16,378 |
| Deferred income taxes (Note 10) | 2,383 | 72,294 |
| Deposits and prepayments for energy | 280 | 7,056 |
| Other | 28,072 | 19,901 |
| | 502,675 | 586,943 |
| Deferred Charges and Other Assets: | | |
| Deferred energy costs - electric (Note 1) | 205,030 | 359,589 |
| Regulatory tax asset (Note 10) | 165,257 | 153,471 |
| Regulatory asset for pension plans (Note 11) | 86,909 | 113,646 |
| Other regulatory assets (Note 1) | 524,460 | 440,369 |
| Risk management assets (Note 9) | 9,069 | 5,379 |
| Risk management regulatory assets - net (Note 9) | 17,186 | 83,886 |
| Unamortized debt issuance costs | 36,551 | 38,856 |
| Other | 70,403 | 33,209 |
| | 1,114,865 | 1,228,405 |
| **TOTAL ASSETS** | $ 6,377,369 | $ 5,987,515 |
| **CAPITALIZATION AND LIABILITIES** | | |
| Capitalization: | | |
| Common shareholder's equity | $ 2,376,740 | $ 2,172,198 |
| Long-term debt | 2,528,141 | 2,380,139 |
| | 4,904,881 | 4,552,337 |
| Current Liabilities: | | |
| Current maturities of long-term debt | 8,642 | 5,948 |
| Accounts payable | 231,205 | 148,003 |
| Accounts payable, affiliated companies | 32,706 | 20,656 |
| Accrued interest | 41,920 | 37,010 |
| Dividends declared | 10,907 | 13,472 |
| Accrued salaries and benefits | 16,881 | 14,989 |
| Current income taxes payable (Note 10) | 3,544 | 3,981 |
| Intercompany Income taxes payable | 15,403 | 884 |
| Deferred income taxes (Note 10) | - | - |
| Risk management liabilities (Note 9) | 26,982 | 84,674 |
| Accrued taxes | 4,529 | 2,671 |
| Deferred energy costs-electric (Note 1) | - | - |
| Other current liabilities | 50,902 | 48,298 |
| | 443,621 | 380,586 |
| Commitments and Contingencies (Note 13) | | |
| Deferred Credits and Other Liabilities: | | |
| Deferred income taxes (Note 10) | 585,168 | 599,747 |
| Deferred investment tax credit | 11,169 | 15,213 |
| Regulatory tax liability (Note 10) | 10,038 | 13,451 |
| Customer advances for construction | 58,890 | 60,040 |
| Accrued retirement benefits | 25,693 | 90,474 |
| Risk management liabilities (Note 9) | 5,116 | 7,061 |
| Regulatory liabilities (Note 1) | 168,381 | 171,298 |
| Other | 164,412 | 97,308 |
| | 1,028,867 | 1,054,592 |
| **TOTAL CAPITALIZATION AND LIABILITIES** | $ 6,377,369 | $ 5,987,515 |

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

**NEVADA POWER COMPANY**
**CONSOLIDATED INCOME STATEMENTS**
**(Dollars in Thousands)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2007** | **2006** | **2005** |
| **OPERATING REVENUES:** | | | |
| Electric | $ 2,356,620 | $ 2,124,081 | $ 1,883,267 |
| **OPERATING EXPENSES:** | | | |
| Operation: | | | |
| Purchased power | 688,606 | 764,850 | 963,888 |
| Fuel for power generation | 594,382 | 552,959 | 277,083 |
| Deferral of energy costs-net | 233,166 | 92,322 | (45,668) |
| Reinstatement of deferred energy (Note 3) | - | (178,825) | - |
| Other | 232,610 | 218,120 | 211,039 |
| Maintenance | 67,482 | 61,899 | 52,040 |
| Depreciation and amortization | 152,139 | 141,585 | 124,098 |
| Taxes: | | | |
| Income taxes (Note 10) | 61,108 | 91,781 | 46,425 |
| Other than income | 29,823 | 28,118 | 25,535 |
| | 2,059,316 | 1,772,809 | 1,654,440 |
| **OPERATING INCOME** | 297,304 | 351,272 | 228,827 |
| **OTHER INCOME (EXPENSE):** | | | |
| Allowance for other funds used during construction | 15,861 | 11,755 | 18,683 |
| Interest accrued on deferred energy | 14,213 | 21,902 | 20,350 |
| Carrying charge for Lenzie (Note 1) | 16,080 | 33,440 | - |
| Reinstated interest on deferred energy (Note 3) | 11,076 | - | - |
| Other income | 14,423 | 16,992 | 25,626 |
| Other expense | (11,352) | (8,480) | (8,525) |
| Income taxes (Note 10) | (17,244) | (25,729) | (17,570) |
| | 43,057 | 49,880 | 38,564 |
| Total Income Before Interest Charges | 340,361 | 401,152 | 267,391 |
| **INTEREST CHARGES:** | | | |
| Long-term debt | 164,002 | 171,188 | 159,106 |
| Interest for Energy Suppliers (Note 13) | - | - | (14,825) |
| Other | 23,861 | 17,038 | 13,563 |
| Allowance for borrowed funds used during construction | (13,196) | (11,614) | (23,187) |
| | 174,667 | 176,612 | 134,657 |
| **NET INCOME** | $ 165,694 | $ 224,540 | $ 132,734 |

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

**NEVADA POWER COMPANY**
**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)**
**(Dollars in Thousands)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2007** | **2006** | **2005** |
| **NET INCOME** | $ 165,694 | $ 224,540 | $ 132,734 |
| **OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX:** | | | |
| Change in market value of risk management assets and liabilities as of December 31 (Net of taxes of $785 in 2005) | - | - | (1,460) |
| Minimum pension liability adjustment (net of taxes of ($520) and $740 in 2006 and 2005, respectively) | - | 965 | (2,769) |
| Change in SFAS 158 liability and amortization (net of taxes of $487) | (904) | - | - |
| **OTHER COMPREHENSIVE INCOME (LOSS)** | (904) | 965 | (4,229) |
| **COMPREHENSIVE INCOME** | $ 164,790 | $ 225,505 | $ 128,505 |

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

**NEVADA POWER COMPANY**
**CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDER'S EQUITY**
**(Dollars in Thousands)**

| | December 31, | | |
|---|---|---|---|
| | **2007** | **2006** | **2005** |
| Common Stock: | | | |
| Balance at Beginning of Year and End of Year | $ 1 | $ 1 | $ 1 |
| Other Paid-In Capital: | | | |
| Balance at Beginning of Year | 2,042,369 | 1,808,848 | 1,576,794 |
| Revaluation of investment | - | - | 119 |
| Transfer of pension assets | - | 33,521 | - |
| Capital contribution from parent | 65,000 | 200,000 | 231,935 |
| Tax Benefit from stock option exercises | 213 | - | - |
| Balance at End of Year | 2,107,582 | 2,042,369 | 1,808,848 |
| Retained Earnings (Deficit): | | | |
| Balance at Beginning of Year | 132,201 | (43,422) | (140,898) |
| FIN 48 Adjustment to beginning balance | 207 | - | - |
| Income for the year | 165,694 | 224,540 | 132,734 |
| Common stock dividends declared | (25,667) | (48,917) | (35,258) |
| Balance at End of Year | 272,435 | 132,201 | (43,422) |
| Accumulated Other Comprehensive Income (Loss): | | | |
| Balance at Beginning of Year | (2,373) | (3,338) | 891 |
| Change in market value of risk management assets and liabilities as of December 31 (Net of taxes of $785 in 2005) | - | - | (1,460) |
| Minimum pension liability adjustment (net of taxes of ($520) and $740 in 2006 and 2005, respectively) | - | 965 | (2,769) |
| Change in SFAS 158 liability and amortization (net of taxes of $487) | (905) | - | - |
| Balance at End of Year | (3,278) | (2,373) | (3,338) |
| Total Common Shareholder's Equity at End of Year | $2,376,740 | $2,172,198 | $1,762,089 |

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

**NEVADA POWER COMPANY**
**CONSOLIDATED STATEMENTS OF CASH FLOWS**
**(Dollars in Thousands)**

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2007** | **2006** | **2005** |
| **CASH FLOWS FROM OPERATING ACTIVITIES:** | | | |
| Net Income | $ 165,694 | $ 224,540 | $ 132,734 |
| Adjustments to reconcile net income to net cash from or (used by) operating activities: | | | |
| Depreciation and amortization | 152,139 | 141,585 | 124,098 |
| Deferred taxes and deferred investment tax credit | 56,868 | 107,392 | 86,910 |
| AFUDC | (15,861) | (11,755) | (41,870) |
| Amortization of deferred energy costs | 203,213 | 120,499 | 131,471 |
| Deferral of energy costs | 15,779 | (49,982) | (186,338) |
| Deferral of energy costs - terminated suppliers | - | 3,896 | 155,119 |
| Reinstatement of deferred energy | - | (178,825) | - |
| Carrying charge on Lenzie plant | (16,080) | (33,440) | - |
| Reinstated interest on deferred energy | (11,076) | - | - |
| Other, net | 5,831 | 3,394 | (7,433) |
| Changes in certain assets and liabilities: | | | |
| Accounts receivable | (29,619) | (35,191) | (57,746) |
| Materials, supplies and fuel | (7,916) | (13,919) | (1,977) |
| Other current assets | (1,395) | 5,421 | 14,434 |
| Accounts payable | 60,269 | (2,431) | 30,855 |
| Payment to terminating supplier | - | (37,410) | - |
| Proceeds from claim on terminating supplier | - | 26,391 | - |
| Accrued retirement benefits | (46,067) | (11,853) | 3,589 |
| Other current liabilities | 11,267 | 5,083 | (107,575) |
| Risk Management assets and liabilities | 3,673 | (2,219) | (6,597) |
| Other assets | (964) | (9,902) | (9,950) |
| Other liabilities | 18,873 | 8,907 | (35,515) |
| Net Cash from Operating Activities | 564,628 | 260,181 | 224,209 |
| **CASH FLOWS USED BY INVESTING ACTIVITIES:** | | | |
| Additions to utility plant | (766,136) | (670,441) | (546,748) |
| AFUDC | 15,861 | 11,755 | 41,870 |
| Customer advances for construction | (1,150) | 10,417 | 18,813 |
| Contributions in aid of construction | 19,576 | 21,241 | 8,544 |
| Investments and other property - net | 2,768 | 7,363 | 1,875 |
| Net Cash used by Investing Activities | (729,081) | (619,665) | (475,646) |
| **CASH FLOWS FROM FINANCING ACTIVITIES:** | | | |
| Proceeds from issuance of long-term debt | 724,391 | 1,687,726 | 150,000 |
| Retirement of long-term debt | (596,339) | (1,554,521) | (238,486) |
| Additional investment by parent company | 65,000 | 200,000 | 230,541 |
| Dividends paid | (28,231) | (35,769) | (35,260) |
| Net Cash from Financing Activities | 164,821 | 297,436 | 106,795 |
| **Net Increase (Decrease) in Cash and Cash Equivalents** | 368 | (62,048) | (144,642) |
| Beginning Balance in Cash and Cash Equivalents | 36,633 | 98,681 | 243,323 |
| Ending Balance in Cash and Cash Equivalents | $ 37,001 | $ 36,633 | $ 98,681 |
| **Supplemental Disclosures of Cash Flow Information:** | | | |
| Cash paid during period for: | | | |
| Interest | $ 164,704 | $ 190,023 | $ 173,775 |
| Income taxes | $ 6,760 | $ 4,714 | $ - |

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

**NEVADA POWER COMPANY**
**CONSOLIDATED STATEMENTS OF CAPITALIZATION**
**(Dollars in Thousands, Except Per Share Amounts)**

| | December 31, | |
|---|---|---|
| | **2007** | **2006** |
| **Common Shareholder's Equity:** | | |
| Common stock, $1.00 par value, 1,000 shares authorized, issued and Outstanding | $ 1 | $ 1 |
| Other paid-in capital | 2,107,582 | 2,042,369 |
| Retained Earnings | 272,435 | 132,201 |
| Accumulated other comprehensive loss | (3,278) | (2,373) |
| Total Common Shareholder's Equity | 2,376,740 | 2,172,198 |
| **Long-Term Debt:** | | |
| **Secured Debt** | | |
| Debt Secured by General and Refunding Mortgage Indenture | | |
| 8.25% Series A due 2011 | 350,000 | 350,000 |
| 6.50% Series I due 2012 | 130,000 | 130,000 |
| 9.00% Series G due 2013 | 17,244 | 227,500 |
| 5.875% Series L due 2015 | 250,000 | 250,000 |
| 5.95% Series M due 2016 | 210,000 | 210,000 |
| 6.65% Series N due 2036 | 370,000 | 370,000 |
| 6.00% Series O due 2018 | 325,000 | 325,000 |
| 6.75% Series R due 2037 | 350,000 | - |
| Subtotal | 2,002,244 | 1,862,500 |
| Variable Rate Notes | | |
| PCRB Series 2000B due 2009 | 15,000 | 15,000 |
| IDRB Series 2000A due 2020 | 100,000 | 100,000 |
| PCRB Series 2006 due 2036 | 39,500 | 39,500 |
| PCRB Series 2006A due 2032 | 40,000 | 40,000 |
| PCRB Series 2006B due 2039 | 13,000 | 13,000 |
| Subtotal | 207,500 | 207,500 |
| **Unsecured Debt** | | |
| Revenue Bonds | | |
| 5.30% Series 1995D due 2011 | 14,000 | 14,000 |
| 5.45% Series 1995D due 2023 | 6,300 | 6,300 |
| 5.50% Series 1995C due 2030 | 44,000 | 44,000 |
| 5.60% Series 1995A due 2030 | 76,750 | 76,750 |
| 5.90% Series 1995B due 2030 | 85,000 | 85,000 |
| 5.90% Series 1997A due 2032 | 52,285 | 52,285 |
| Subtotal | 278,335 | 278,335 |
| Unamortized bond premium and discount, net | (12,732) | (12,757) |
| Obligations under capital leases | 61,424 | 50,479 |
| Current maturities and sinking fund requirements | (8,642) | (5,948) |
| Other, excluding current portion | 12 | 30 |
| Total Long-Term Debt | 2,528,141 | 2,380,139 |
| **TOTAL CAPITALIZATION** | $ 4,904,881 | $ 4,552,337 |

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

**SIERRA PACIFIC POWER COMPANY**
**CONSOLIDATED BALANCE SHEETS**
**(Dollars in Thousands)**

| | December 31, | |
|---|---|---|
| | **2007** | **2006** |
| **ASSETS** | | |
| Utility Plant at Original Cost: | | |
| Plant in service | $ 2,897,219 | $ 2,766,672 |
| Less accumulated provision for depreciation | 1,119,045 | 1,057,165 |
| | 1,778,174 | 1,709,507 |
| Construction work-in-progress | 492,539 | 227,500 |
| | 2,270,713 | 1,937,007 |
| Investments and other property, net (Note 4) | 570 | 609 |
| Current Assets: | | |
| Cash and cash equivalents | 23,807 | 53,260 |
| Accounts receivable less allowance for uncollectible accounts: 2007-$5,669; 2006 - $6,732 | 160,014 | 170,106 |
| Deferred energy costs - electric (Note 1) | - | 38,956 |
| Materials, supplies and fuel, at average cost | 48,799 | 42,990 |
| Risk management assets (Note 9) | 6,208 | 10,927 |
| Deferred income taxes (Note 10) | 17,728 | - |
| Deposits and prepayments for energy | 862 | 8,912 |
| Other | 16,393 | 11,184 |
| | 273,811 | 336,335 |
| Deferred Charges and Other Assets: | | |
| Deferred energy costs - electric (Note 1) | - | 22,697 |
| Regulatory tax asset (Note 10) | 102,591 | 109,699 |
| Regulatory asset for pension plans (Note 11) | 43,778 | 106,666 |
| Other regulatory assets (Note 1) | 233,827 | 228,255 |
| Risk management assets (Note 9) | 3,360 | 2,207 |
| Risk management regulatory assets - net (Note 9) | 8,881 | 39,025 |
| Unamortized debt issuance costs | 19,976 | 17,981 |
| Other | 19,017 | 7,356 |
| | 431,430 | 533,886 |
| **TOTAL ASSETS** | $ 2,976,524 | $ 2,807,837 |
| **CAPITALIZATION AND LIABILITIES** | | |
| Capitalization: | | |
| Common shareholder's equity | $ 1,001,840 | $ 884,737 |
| Long-term debt | 1,084,550 | 1,070,858 |
| | 2,086,390 | 1,955,595 |
| Current Liabilities: | | |
| Current maturities of long-term debt | 101,643 | 2,400 |
| Accounts payable | 94,722 | 89,743 |
| Accounts payable, affiliated companies | 19,288 | 11,769 |
| Accrued interest | 15,750 | 7,200 |
| Dividends declared | 5,333 | 6,736 |
| Accrued salaries and benefits | 14,830 | 15,209 |
| Current income taxes payable (Note 10) | - | - |
| Intercompany income taxes payable | 2,479 | 9,055 |
| Deferred income taxes (Note 10) | - | 8,881 |
| Risk management liabilities (Note 9) | 12,527 | 38,391 |
| Accrued taxes | 3,542 | 3,407 |
| Deferred energy costs-electric (Note 1) | 17,573 | - |
| Deferred energy costs - gas (Note 1) | 11,369 | 112 |
| Other current liabilities | 15,015 | 12,013 |
| | 314,071 | 204,916 |
| Commitments and Contingencies (Note 13) | | |
| Deferred Credits and Other Liabilities: | | |
| Deferred income taxes (Note 10) | 267,801 | 278,515 |
| Deferred investment tax credit | 17,726 | 20,005 |
| Regulatory tax liability (Note 10) | 18,407 | 20,624 |
| Customer advances for construction | 41,235 | 31,855 |
| Accrued retirement benefits | 48,025 | 124,254 |
| Risk management liabilities (Note 9) | 2,253 | 3,685 |
| Regulatory liabilities (Note 1) | 135,645 | 130,605 |
| Other | 44,971 | 37,783 |
| | 576,063 | 647,326 |
| **TOTAL CAPITALIZATION AND LIABILITIES** | $ 2,976,524 | $ 2,807,837 |

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

**SIERRA PACIFIC POWER COMPANY**
**CONSOLIDATED INCOME STATEMENTS**
**(Dollars in Thousands)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2007** | **2006** | **2005** |
| **OPERATING REVENUES:** | | | |
| Electric | $ 1,038,867 | $ 1,020,162 | $ 967,427 |
| Gas | 205,430 | 210,068 | 178,270 |
| | 1,244,297 | 1,230,230 | 1,145,697 |
| **OPERATING EXPENSES:** | | | |
| Operation: | | | |
| Purchased power | 348,299 | 344,590 | 352,098 |
| Fuel for power generation | 242,973 | 247,626 | 233,653 |
| Gas purchased for resale | 150,879 | 160,739 | 140,850 |
| Deferred energy costs disallowed (Note 3) | 14,171 | - | - |
| Deferral of energy costs - electric - net | 63,873 | 47,043 | 8,110 |
| Deferral of energy costs - gas - net | 10,763 | 6,947 | (749) |
| Other | 142,348 | 141,350 | 131,901 |
| Maintenance | 31,553 | 31,273 | 26,690 |
| Depreciation and amortization | 83,393 | 87,279 | 90,569 |
| Taxes: | | | |
| Income taxes (Note 10) | 29,991 | 23,570 | 26,038 |
| Other than income | 20,097 | 19,796 | 20,233 |
| | 1,138,340 | 1,110,213 | 1,029,393 |
| **OPERATING INCOME** | 105,957 | 120,017 | 116,304 |
| **OTHER INCOME (EXPENSE):** | | | |
| Allowance for other funds used during construction | 15,948 | 6,471 | 1,639 |
| Interest accrued on deferred energy | 865 | 5,996 | 7,092 |
| Other income | 8,091 | 9,412 | 5,940 |
| Other expense | (8,441) | (8,422) | (7,493) |
| Income taxes (Note 10) | 3,982 | (4,259) | (2,341) |
| | 20,445 | 9,198 | 4,837 |
| Total Income Before Interest Charges | 126,402 | 129,215 | 121,141 |
| **INTEREST CHARGES:** | | | |
| Long-term debt | 67,502 | 71,869 | 69,240 |
| Interest for Energy Suppliers (Note 13) | - | - | (2,396) |
| Other | 6,004 | 5,142 | 3,727 |
| Allowance for borrowed funds used during construction | (12,771) | (5,505) | (1,504) |
| | 60,735 | 71,506 | 69,067 |
| **NET INCOME** | 65,667 | 57,709 | 52,074 |
| Preferred stock dividend and premium on redemption | - | 2,341 | 3,900 |
| **EARNINGS APPLICABLE TO COMMON STOCK** | $ 65,667 | $ 55,368 | $ 48,174 |

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

**SIERRA PACIFIC POWER COMPANY**

**CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)**

**(Dollars in Thousands)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2007** | **2006** | **2005** |
| **NET INCOME** | $ 65,667 | $ 57,709 | $ 52,074 |
| **OTHER COMPREHENSIVE INCOME (LOSS), NET OF TAX:** | | | |
| Change in market value of risk management assets and liabilities as of December 31 (net of taxes of $370 in 2005) | - | - | (686) |
| Minimum pension liability adjustment (net of taxes of ($462) and $632 in 2006 and 2005, respectively) | - | 861 | (1,173) |
| Change in SFAS 158 liability and amortization (net of taxes of $620) | (1,153) | - | - |
| **OTHER COMPREHENSIVE INCOME (LOSS)** | (1,153) | 861 | (1,859) |
| **COMPREHENSIVE INCOME** | $ 64,514 | $ 58,570 | $ 50,215 |

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

**SIERRA PACIFIC POWER COMPANY**
**CONSOLIDATED STATEMENTS OF COMMON SHAREHOLDER'S EQUITY**
**(Dollars in Thousands)**

| | December 31, | | |
|---|---|---|---|
| | **2007** | **2006** | **2005** |
| Common Stock: | | | |
| Balance at Beginning of Year and End of Year | $ 4 | $ 4 | $ 4 |
| Other Paid-In Capital: | | | |
| Balance at Beginning of Year | 935,453 | 810,103 | 810,103 |
| Transfer of Goodwill (Note 18) | - | 18,888 | - |
| Transfer of pension assets | - | 31,462 | - |
| Capital contribution from parent | 65,000 | 75,000 | - |
| Tax Benefit from stock option exercises | 142 | | |
| Balance at End of Year | 1,000,595 | 935,453 | 810,103 |
| Retained Earnings (Deficit): | | | |
| Balance at Beginning of Year | (49,789) | (80,538) | (104,779) |
| FIN 48 Adjustment to beginning balance | 280 | - | - |
| Income before preferred dividends | 65,667 | 57,709 | 52,074 |
| Preferred stock redemption | - | (1,366) | |
| Preferred stock dividends declared | - | (975) | (3,900) |
| Common stock dividends declared | (12,833) | (24,619) | (23,933) |
| Balance at End of Year | 3,325 | (49,789) | (80,538) |
| Accumulated Other Comprehensive Income (Loss): | | | |
| Balance at Beginning of Year | (931) | (1,792) | 67 |
| Change in market value of risk management assets and liabilities as of December 31 (Net of taxes of $370 in 2005) | - | - | (686) |
| Minimum pension liability adjustment (net of taxes of ($462) and $632 in 2006 and 2005, respectively) | - | 861 | (1,173) |
| Change in SFAS 158 liability and amortization (net of taxes of $620) | (1,153) | - | - |
| Balance at End of Year | (2,084) | (931) | (1,792) |
| Total Common Shareholder's Equity at End of Year | $ 1,001,840 | $ 884,737 | $ 727,777 |

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

**SIERRA PACIFIC POWER COMPANY**
**CONSOLIDATED STATEMENTS OF CASH FLOWS**
**(Dollars in Thousands)**

| | Year Ended December 31, | | |
|---|---|---|---|
| | **2007** | **2006** | **2005** |
| **CASH FLOWS FROM OPERATING ACTIVITIES:** | | | |
| Net Income | $ 65,667 | $ 57,709 | $ 52,074 |
| Adjustments to reconcile net income to net cash from operating activities: | | | |
| Depreciation and amortization | 83,393 | 87,279 | 90,569 |
| Deferred taxes and deferred investment tax credit | (36,713) | (39,361) | 209 |
| AFUDC | (15,948) | (6,471) | (3,143) |
| Amortization of deferred energy costs - electric | 43,694 | 46,322 | 56,750 |
| Amortization of deferred energy costs - gas | 701 | 6,234 | 1,446 |
| Deferral of energy costs - electric | 35,532 | (4,755) | (54,765) |
| Deferral of energy costs - gas | 10,668 | 436 | (2,519) |
| Deferral of energy costs - terminated suppliers | - | 4,845 | 62,921 |
| Other, net | 14,577 | 16,935 | 318 |
| Changes in certain assets and liabilities: | | | - |
| Accounts receivable | 10,092 | 36,171 | (11,631) |
| Materials, supplies and fuel | (5,809) | (1,382) | (10,272) |
| Other current assets | 2,839 | 18,204 | 3,106 |
| Accounts payable | 15,010 | 19,670 | 11,573 |
| Payment to terminating supplier | - | (27,958) | - |
| Proceeds from claim on terminating supplier | - | 14,974 | - |
| Accrued retirement benefits | (25,248) | 8,781 | (51) |
| Other current liabilities | 11,196 | (925) | (48,603) |
| Risk Management assets and liabilities | 6,415 | (3,731) | (88) |
| Other assets | 3,462 | (220) | - |
| Other liabilities | (5,349) | (2,320) | 12,237 |
| Net Cash from by Operating Activities | 214,179 | 230,437 | 160,131 |
| **CASH FLOWS USED BY INVESTING ACTIVITIES:** | | | |
| Additions to utility plant | (431,190) | (315,578) | (139,646) |
| AFUDC | 15,948 | 6,471 | 3,143 |
| Customer advances for construction | 9,380 | 6,931 | 8,545 |
| Contributions in aid of construction | 12,590 | 17,551 | 14,807 |
| Investments and other property - net | 39 | 233 | 157 |
| Net Cash used by Investing Activities | (393,233) | (284,392) | (112,994) |
| **CASH FLOWS FROM FINANCING ACTIVITIES:** | | | |
| Change in restricted cash and investments | - | 3,612 | 2,034 |
| Proceeds from issuance of long-term debt | 521,992 | 804,157 | - |
| Retirement of long-term debt | (423,155) | (742,514) | (2,504) |
| Redemption of preferred stock | - | (51,366) | - |
| Investment by parent company | 65,000 | 75,000 | - |
| Dividends paid | (14,236) | (19,827) | (27,833) |
| Net Cash from Financing Activities | 149,601 | 69,062 | (28,303) |
| **Net Increase (Decrease) in Cash and Cash Equivalents** | (29,453) | 15,107 | 18,834 |
| Beginning Balance in Cash and Cash Equivalents | 53,260 | 38,153 | 19,319 |
| Ending Balance in Cash and Cash Equivalents | $ 23,807 | $ 53,260 | $ 38,153 |
| **Supplemental Disclosures of Cash Flow Information:** | | | |
| Cash paid during period for: | | | |
| Interest | $ 59,496 | $ 83,327 | $ 71,496 |
| Income taxes | $ 64 | $ 12 | $ - |
| **Noncash Activities:** | | | |
| Transfer of Regulatory Asset (Note 3) | $ - | $ 18,888 | $ - |

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

**SIERRA PACIFIC POWER COMPANY**
**CONSOLIDATED STATEMENTS OF CAPITALIZATION**
**(Dollars in Thousands, Except Per Share Amounts)**

| | December 31, | |
|---|---|---|
| | **2007** | **2006** |
| **Common Shareholder's Equity:** | | |
| Common stock, $3.75 par value, 20,000,000 shares authorized, 1,000 shares issued and outstanding | $ 4 | $ 4 |
| Other paid-in capital | 1,000,595 | 935,453 |
| Retained Earnings (Deficit) | 3,325 | (49,789) |
| Accumulated other comprehensive loss | (2,084) | (931) |
| Total Common Shareholder's Equity | 1,001,840 | 884,737 |
| **Long-Term Debt:** | | |
| **Secured Debt** | | |
| Debt Secured by General and Refunding Mortgage Indenture | | |
| 8.00% Series A due 2008 | 99,243 | 320,000 |
| 6.25% Series H due 2012 | 100,000 | 100,000 |
| 6.00% Series M due 2016 | 300,000 | 300,000 |
| 5.00% Series 2001 due 2036 | - | 80,000 |
| 6.75% Series P due 2037 | 325,000 | - |
| Subtotal | 824,243 | 800,000 |
| Variable Rate Notes | | |
| PCRB Series 2006 due 2029 | 49,750 | 49,750 |
| PCRB Series 2006A due 2031 | 58,700 | 58,700 |
| PCRB Series 2006B due 2036 | 75,000 | 75,000 |
| PCRB Series 2006C due 2036 | 84,800 | 84,800 |
| WFRB Series 2007A due 2036 | 40,000 | - |
| WFRB Series 2007B due 2036 | 40,000 | - |
| Subtotal | 348,250 | 268,250 |
| **Unsecured Debt** | | |
| Unamortized bond premium and discount, net | 10,700 | (392) |
| Current maturities and sinking fund requirements | (101,643) | (2,400) |
| Other, excluding current portion | 3,000 | 5,400 |
| Total Long-Term Debt | 1,084,550 | 1,070,858 |
| **TOTAL CAPITALIZATION** | $ 2,086,390 | $ 1,955,595 |

## 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). 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 67% of the consolidated assets of SPR at December 31, 2007. NPC provides electricity to approximately 826,000 customers in the communities of Las Vegas, North Las Vegas, Henderson, Searchlight, Laughlin and adjoining areas, including Nellis Air Force Base. Service is also provided to the Department of Energy's Nevada Test Site in Nye County. The consolidated financial statements of SPR include NPC's wholly-owned subsidiary, Nevada Electric Investment Company (NEICO).

SPPC is an operating public utility that provides electric service in northern Nevada and northeastern California. SPPC also provides natural gas service in the Reno/Sparks area of Nevada. The assets of SPPC represent approximately 31% of the consolidated assets of SPR at December 31, 2007. SPPC provides electricity to approximately 366,000 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 149,000 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 was 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 accounted for its joint venture interest under the equity method. In December 2006, TGPC substantially sold its partnership interest in the joint venture. The remaining partnership interest was sold in 2007. See Note 4, Investment in Subsidiaries and Other Property.

### Regulatory Accounting and Other Regulatory Assets

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

In addition to the deferral of energy costs discussed below, items to which SPR and the Utilities apply regulatory accounting are included in the tables below.

Regulatory assets represent incurred costs that have been deferred because it is probable they will be recovered through future rates collected from customers. If at any time the incurred costs no longer meet these criteria, these costs are charged to earnings. Regulatory liabilities generally represent obligations to make refunds to customers for previous collections, except for cost

of removal which represents the cost of removing future electric and gas assets. Management regularly assesses whether the regulatory assets are probable of future recovery by considering actions of regulators, current laws related to regulation, applicable regulatory environment changes and the status of any current and pending or potential deregulation legislation.

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

**SIERRA PACIFIC RESOURCES**
OTHER REGULATORY ASSETS AND LIABILITIES
(Dollars in Thousands)

| | As of December 31, 2007 | | | | | |
|---|---|---|---|---|---|---|
| | | Receiving Regulatory Treatment | | | | |
| DESCRIPTION | Remaining Amortization Period | Earning a Return(1) | Not Earning a Return | Pending Regulatory Treatment | 2007 Total | As of December 31, 2006 Total |
| Regulatory Assets | | | | | | |
| Loss on reacquired debt | Term of Related Debt | $ 100,271 | $ - | $ - | $ 100,271 | $ 87,154 |
| Lenzie | 2042 | - | 38,619 | 41,665 | 80,284 | 52,456 |
| Mohave Plant and deferred costs | 2015 | 25,440 | (3,287) | (3,929) | 18,224 | 17,835 |
| Clark units 1-3 | Various thru 2011 | 9,095 | - | 7,050 | 16,145 | 16,735 |
| Piñon Pine | Various thru 2029 | 33,665 | 5,556 | 1,408 | 40,629 | 42,001 |
| Plant assets | Various thru 2031 | 2,694 | - | 320 | 3,014 | 2,876 |
| Asset retirement obligations | | - | - | 36,498 | 36,498 | 16,112 |
| Nevada divestiture costs | 2012 | 19,469 | - | - | 19,469 | 23,983 |
| Merger transition/transaction costs | 2016 | - | 25,006 | - | 25,006 | 28,916 |
| Merger severance/relocation | 2016 | - | 13,761 | - | 13,762 | 15,884 |
| Merger goodwill | 2046 | - | 285,365 | - | 285,365 | 293,199 |
| California restructure costs | Thru 2009 | 490 | 550 | - | 1,040 | 1,859 |
| Conservation programs | Thru 2012 | 36,694 | - | 42,349 | 79,043 | 53,275 |
| Legal costs | | - | - | 7,138 | 7,138 | 8,376 |
| Peabody coal costs | | - | - | 17,406 | 17,406 | - |
| Legal fees-Western Energy Crisis | 2010 | 5,259 | - | - | 5,259 | - |
| Other costs | Thru 2017 | 1,068 | 4,719 | 3,948 | 9,735 | 7,963 |
| Subtotal | | $ 234,145 | $ 370,289 | $ 153,853 | $ 758,287 | $ 668,624 |
| Regulatory asset for pension plans | | - | 133,984 | - | 133,984 | 223,218 |
| Total regulatory assets | | $ 234,145 | $ 504,273 | $ 153,853 | $ 892,271 | $ 891,842 |
| Regulatory Liabilities | | | | | | |
| Cost of removal | Various | $ 291,274 | $ - | $ - | $ 291,274 | $ 283,641 |
| Gain on property sales | Various thru 2008 | 1,829 | - | - | 1,829 | 4,531 |
| SO2 allowances | Various thru 2013 | 746 | - | - | 746 | 745 |
| Plant liability | 2008 | 259 | - | - | 259 | 1,038 |
| Impact charge | 2008 | 711 | - | - | 711 | 2,722 |
| Depreciation-customer advances | | - | - | 8,745 | 8,745 | 8,775 |
| Domestic production tax deduction | | - | - | 380 | 380 | - |
| Other | 2008 | - | 82 | - | 82 | 451 |
| Total regulatory liabilities | | $ 294,819 | $ 82 | $ 9,125 | $ 304,026 | $ 301,903 |

**NEVADA POWER COMPANY**
OTHER REGULATORY ASSETS AND LIABILITIES
(Dollars in Thousands)

| DESCRIPTION | Remaining Amortization Period | As of December 31, 2007 Receiving Regulatory Treatment Earning a Return(1) | Not Earning a Return | Pending Regulatory Treatment | 2007 Total | As of December 31, 2006 Total |
|---|---|---|---|---|---|---|
| Regulatory Assets | | | | | | |
| Loss on reacquired debt | Term of Related Debt | $ 67,414 | $ - | $ - | $ 67,414 | $ 60,026 |
| Lenzie | 2042 | - | 38,619 | 41,665 | 80,284 | 52,456 |
| Mohave | 2015 | 25,440 | (3,287) | (3,929) | 18,224 | 17,835 |
| Clark units 1-3 | 2011 | 9,095 | - | 7,050 | 16,145 | 16,735 |
| Asset retirement obligations | | - | - | 32,059 | 32,059 | 11,081 |
| Nevada divestiture costs | 2012 | 11,872 | - | - | 11,872 | 14,665 |
| Merger transition/transaction costs | 2014 | - | 17,446 | - | 17,446 | 20,237 |
| Merger severance/relocation | 2014 | - | 6,376 | - | 6,376 | 7,397 |
| Merger goodwill | 2044 | - | 179,436 | - | 179,436 | 184,386 |
| Conservation programs | 2013 | 33,367 | - | 29,813 | 63,180 | 42,636 |
| Legal costs | | - | - | 7,138 | 7,138 | 8,376 |
| Peabody coal costs | | - | - | 17,406 | 17,406 | - |
| Legal fees-Western Energy Crisis | 2010 | 2,801 | - | - | 2,801 | - |
| Other costs | 2009 | 551 | 4,128 | - | 4,679 | 4,539 |
| Subtotal | | $ 150,540 | $ 242,718 | $ 131,202 | $ 524,460 | $ 440,369 |
| Regulatory asset for pension plans | | - | 86,909 | - | 86,909 | 113,646 |
| Total regulatory assets | | $ 150,540 | $ 329,627 | $ 131,202 | $ 611,369 | $ 554,015 |
| Regulatory Liabilities | | | | | | |
| Cost of removal | Various | $ 161,690 | $ - | $ - | $ 161,690 | $ 162,196 |
| Gain on property sales | 2008 | 1,829 | - | - | 1,829 | 4,531 |
| SO2 allowances | Various thru 2013 | 746 | - | - | 746 | 745 |
| Depreciation-customer advances | | - | - | 3,736 | 3,736 | 3,701 |
| Domestic production tax deduction | | - | - | 380 | 380 | - |
| Other | | - | - | - | - | 125 |
| Total regulatory liabilities | | $ 164,265 | $ - | $ 4,116 | $ 168,381 | $ 171,298 |

**SIERRA PACIFIC POWER COMPANY**
OTHER REGULATORY ASSETS AND LIABILITIES
(Dollars in Thousands)

| (dollars in thousands) DESCRIPTION | Remaining Amortization Period | As of December 31, 2007 Receiving Regulatory Treatment Earning a Return(1) | Not Earning a Return | Pending Regulatory Treatment | 2007 Total | As of December 31, 2006 Total |
|---|---|---|---|---|---|---|
| Regulatory assets | | | | | | |
| Loss on reacquired debt | Term of Related Debt | $ 32,857 | $ - | $ - | $ 32,857 | $ 27,128 |
| Piñon Pine | Various thru 2029 | 33,665 | 5,556 | 1,408 | 40,629 | 42,001 |
| Plant assets | Various thru 2031 | 2,694 | - | 320 | 3,014 | 2,876 |
| Asset retirement obligations | | - | - | 4,439 | 4,439 | 5,031 |
| Nevada divestiture costs | 2012 | 7,597 | - | - | 7,597 | 9,318 |
| Merger transition/transaction costs | 2016 | - | 7,560 | - | 7,560 | 8,679 |
| Merger severance/relocation | 2016 | - | 7,385 | - | 7,385 | 8,487 |
| Merger goodwill | 2046 | - | 105,929 | - | 105,929 | 108,813 |
| California restructure costs | Thru 2009 | 490 | 550 | - | 1,040 | 1,859 |
| Conservation programs | Thru 2012 | 3,327 | - | 12,536 | 15,863 | 10,639 |
| Legal fees-Western Energy Crisis | | 2,458 | - | - | 2,458 | - |
| Other costs | Various thru 2017 | 517 | 591 | 3,948 | 5,056 | 3,424 |
| Subtotal | | $ 83,605 | $ 127,571 | $ 22,651 | $ 233,827 | $ 228,255 |
| Regulatory asset for pension plans | | | 43,778 | - | 43,778 | 106,666 |
| Total regulatory assets | | $ 83,605 | $ 171,349 | $ 22,651 | $ 277,605 | $ 334,921 |
| Regulatory Liabilities | | | | | | |
| Cost of removal | Various | $ 129,584 | $ - | $ - | 129,584 | $ 121,445 |
| Plant liability | 2008 | 259 | - | - | 259 | 1,038 |
| Impact charge | 2008 | 711 | - | - | 711 | 2,722 |
| Depreciation-customer advances | | - | - | 5,009 | 5,009 | 5,074 |
| Other | 2008 | - | 82 | | 82 | 326 |
| Total regulatory liabilities | | $ 130,554 | $ 82 | $ 5,009 | $ 135,645 | $ 130,605 |

(1) Earning a Return includes either a carrying charge on the asset/liability balance, or a return as a component of weighted cost of capital.

**Deferral of Energy Costs**

Nevada and California statutes permit regulated utilities to 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.

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 in accordance with the provisions of SFAS No. 71. 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.

Nevada law requires the Utilities file annual deferred energy accounting adjustment applications 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." Nevada law also 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, 2007 | | | |
|---|---|---|---|---|---|
| Description | | NPC Electric | SPPC Electric | SPPC Gas | SPR Total |
| Unamortized balances approved for collection in current rates | | | | | |
| Reinstatement of Deferred Energy | (effective 6/07, 10 years)[1] | $ 179,409 | $ - | $ - | $ 179,409 |
| Electric - NPC Period 5 | (effective 8/06, 2 years) | 53,876 | - | - | 53,876 |
| Electric - SPPC Period 5 | (effective 7/06, 2 years) | - | 5,733 | - | 5,733 |
| Electric - NPC Period 6 | (effective 6/07, 14 months) | 26,048 | - | - | 26,048 |
| Electric - SPPC Period 6 | (effective 7/07, 1 year) | - | 7,524 | - | 7,524 |
| Natural Gas – Period 6 | (effective 12/06, 1 year) | - | - | 161 | 161 |
| Natural Gas – Period 7 | (effective 12/07, 1 year) | - | - | (1,369) | (1,369) |
| Western Energy Crisis Rate Case-NPC [2] | (effective 6/07, 3 years) | 65,344 | - | - | 65,344 |
| Balances pending PUCN approval [3] | | (43,699) | (34,198) | (10,161) | (88,058) |
| Cumulative CPUC Balance | | - | 3,368 | - | 3,368 |
| Total | | $ 280,978 | $ (17,573) | $ (11,369) | $ 252,036 |
| Current Assets | | | | | |
| Deferred energy costs - electric | | $ 75,948 | $ - | $ - | $ 75,948 |
| Deferred Assets | | | | | |
| Deferred energy costs - electric | | 205,030 | - | - | 205,030 |
| Current Liabilities | | | | | |
| Deferred energy costs – electric | | - | (17,573) | - | (17,573) |
| Deferred energy costs – gas | | - | - | (11,369) | (11,369) |
| Total | | $ 280,978 | $ (17,573) | $ (11,369) | $ 252,036 |

| Description | | December 31, 2006 NPC Electric | SPPC Electric | SPPC Gas | SPR Total |
|---|---|---|---|---|---|
| Unamortized balances approved for collection in current rates | | | | | |
| Electric - NPC Period 1 | (Reinstatement of deferred energy )[1] | $ 178,825 | $ - | $ - | $ 178,825 |
| Electric - NPC Period 3 | (effective 4/05, 2 years) | (4,067) | - | - | (4,067) |
| Electric - SPPC Period 3 | (effective 6/05, 27 months) | - | 6,034 | - | 6,034 |
| Electric - NPC Period 4 | (effective 4/05, 2 years) | 6,347 | - | - | 6,347 |
| Electric - NPC Period 5 | (effective 8/06, 2 years) | 153,720 | - | - | 153,720 |
| Electric - SPPC Period 5 | (effective 7/06, 2 years) | - | 27,657 | - | 27,657 |
| Nat. Gas - Per 6, LPG - Per 5 | (effective 12/06, 1 year) | - | - | 902 | 902 |
| Balances pending PUCN approval | | 72,280 | 16,220 | - | 88,500 |
| Cumulative CPUC Balance | | - | 9,956 | - | 9,956 |
| Balances accrued since end of periods submitted for PUCN approval | | 1,693 | (14,479) | (1,014) | (13,800) |
| Claims for terminated supply contracts[2] | | 80,095 | 16,265 | - | 96,360 |
| Total | | $ 488,893 | $ 61,653 | $ (112)[3] | $ 550,434 |
| Current Assets | | | | | |
| Deferred energy costs - electric | | $ 129,304 | $ 38,956 | $ - | $ 168,260 |
| Deferred Assets | | | | | |
| Deferred energy costs - electric | | 359,589 | 22,697 | - | 382,286 |
| Current Liabilities | | | | | |
| Deferred energy costs – gas | | - | - | (112) | (112) |
| Total | | $ 488,893 | $ 61,653 | $ (112) | $ 550,434 |

(1) Reinstatement of Deferred Energy is discussed in Note 3, Regulatory Actions.
(2) NPC's Western Energy Crisis Rate Case is discussed in Note 3, Regulatory Actions
(3) Credit balances represent potential refunds to the Utilities' customers.

**Carrying Charge on the Lenzie Generating Station**

In 2004, the Public Utilities Commission of Nevada (PUCN) granted NPC's request to designate the Chuck Lenzie Generating Station (Lenzie) as a critical facility and allowed a 2% enhanced Return on Equity (ROE) to be applied to the Lenzie construction costs expended after acquisition. The order allowed for an additional 1% enhanced ROE if the two Lenzie generating units were brought on line early. In addition, the PUCN granted NPC's request to begin accumulating a carrying charge as a regulatory asset including the 3% enhanced ROE (collectively referred to as "carrying charges"), until the plant is included in rates. Units 1 and 2 were declared commercially operable in January 2006 and April 2006, respectively, qualifying for the incentive ROE treatment.

Through June 30, 2007, NPC had accumulated approximately $57.6 million in carrying charges; however, $8.1 million ($8.0 million as of December 31, 2007) of this amount was not recorded for financial reporting purposes as it represents equity carrying costs that are not recognized until collected through rates. For the year ended December 31, 2007, NPC recognized $16.1 million in income. NPC no longer records a separate carrying charge component related to Lenzie as the carrying charge is in current rates effective June 1, as discussed below.

In May 2007, the PUCN issued its order on NPC's 2006 General Rate Case (GRC) authorizing recovery of the carrying charges, effective as of June 1, 2007. NPC was authorized to recover over a 35 year period $30.3 million of the carrying charges calculated through the certification period ending October 31, 2006. Beginning June 1, 2007, NPC began recognizing its full return on Lenzie through rates rather than as a separate carrying charge component. NPC will seek recovery of the remaining $27.3 million of carrying charges calculated subsequent to the certification period in its next GRC.

**Mohave Generation Station (Mohave)**

NPC owns approximately 14% of the Mohave facility. Southern California Edison (SCE) is the operating partner of Mohave.

When operating, Mohave obtained 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 was 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.

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 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. In 1999, the plant owners and

plaintiffs filed a settlement with the court, which resulted in a consent decree, approved by the court in November 1999. The consent decree established emission limits for sulfur dioxide and opacity and required installation of air pollution controls for sulfur dioxide, nitrogen oxides, and particulate matter. Pursuant to the decree, Mohave Units 1 and 2 ceased operations as of January 2006 as the new emission limits were not met. Due to the lack of resolution regarding continual availability of the coal and water supply with the Tribes, the Owners did not proceed with the Consent Decree.

In December 2005, the Owners of the Mohave plant suspended operation, pending resolution of these issues. However, in June 2006, majority stake holder SCE announced it would no longer participate in the efforts to return the plant to service. As a result, NPC decided it is not economically feasible to continue its participation in the project. In September 2006, Salt River's co-tenancy agreement expired and the operating agreement between the Owners expired in July 2006. The Owners are negotiating an extension of both agreements including a process that addresses how Owners may sell or assign their right, title, interest and obligations in Mohave.

In NPC's 2006 GRC, the PUCN approved the recovery of the net book value of the plant and costs and savings related to the plant through the certification period of October 31, 2006. The balance to be recovered, over an eight year period, is approximately $22.2 million as of December 31, 2007 and is recorded in Other Regulatory Assets. All costs incurred subsequent to the certification period will continue to be accumulated in Other Regulatory Assets and NPC will seek recovery in its next GRC for those costs. The accumulated credit balance subsequent to the certification period is approximately $3.9 million as of December 31, 2007.

**Utility Plant**

The cost of additions, including betterments and replacements of units of property, are charged to utility plant. When units of property are replaced, renewed or retired, their cost plus removal or disposal costs, less salvage proceeds, are charged to accumulated depreciation. The cost of current repairs and minor replacements are charged to maintenance expense when incurred, with the exception of long term service agreements. These agreements may have annual payment amounts for repairs which could vary over the life of the agreement between maintenance expense and amounts to be capitalized. To ensure consistency in annual expense for rate making purposes, the amounts to be charged to maintenance expense are smoothed over the life of the contract, with an offset to a regulatory asset or liability account. Amounts prepaid for capital expenditure are recorded in a prepaid asset account.

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

**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, however, 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 rate used during 2007 was 9.06% and 9.03% during 2006 and 2005. SPPC's AFUDC rates used during 2007, 2006 and 2005 were 8.60%, 8.97% and 8.96%, respectively. As specified by the PUCN, certain projects may be assigned a lower or higher AFUDC rate due to specific 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. Depreciation expense 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, as authorized by the PUCN and stated as a percentage of the average depreciable property balances for those years, was for 2007 approximately 2.66% , and 3.15% during 2006 and 2005. SPPC's depreciation provision for 2007, 2006 and 2005, as authorized by the PUCN and stated as a percentage of the average cost of depreciable property, was approximately 3.01%, 3.08% and 3.3%, respectively.

**Impairment of Long-Lived Assets**

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

**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.

**Federal Income Taxes**

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

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, 2007, include unbilled receivables of $106 million and $79 million for NPC and SPPC, respectively. Accounts receivable as of December 31, 2006, include unbilled receivables of $92 million and $83 million for NPC and SPPC, respectively.

**Asset Retirement Obligations**

SFAS No. 143 "Accounting for Asset Retirement Obligations" provides accounting requirements for the recognition and measurement of liabilities associated with the retirement of tangible long-lived assets. Under the standard, these liabilities are recognized at fair value as incurred and capitalized as part of the cost of the related tangible long-lived assets. Accretion of the liabilities due to the passage of time is classified as an operating expense. Retirement obligations associated with long-lived assets included within the scope of SFAS No. 143 are those for which a legal obligation exists under enacted laws, statutes written or oral contracts, including obligations arising under the doctrine of promissory estoppel. SPR, NPC and SPPC adopted SFAS No. 143 on January 1, 2003.

Management's methodology to assess its legal obligation included an inventory of assets by company, system and components and a review of rights of way and easements, regulatory orders, leases and federal, state, and local environmental laws. Management 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. Provisions of the lease require the lessees to remove the facilities upon request of the Navajo Nation at the expiration of the leases.

In March, 2005, the Financial Accounting Standards Board (FASB) issued Interpretation No. 47 as clarification to SFAS No. 143. This Interpretation was effective no later than the end of fiscal years ending after December 15, 2005 (December 31, 2005, for calendar-year enterprises). The Interpretation clarified the term conditional retirement obligation as used in SFAS No. 143 as well as when an entity would have sufficient information to reasonably estimate the fair value of an asset retirement obligation.

Similar to the methodology used to assess legal obligations under SFAS 143, management reviewed the inventory of assets by system and components, as well as rights of way and easements, regulatory orders, leases and federal, state, and local environmental laws. Management has determined evaporative ponds, dry ash landfills, fuel storage tanks, asbestos and oils treated with Poly Chlorinated Biphenyl to have met the conditional asset retirement obligations of FIN 47.

The following table presents a reconciliation of the beginning and ending aggregate carrying amounts of asset retirement obligation for the years presented below (dollars in thousands):

| | SPR | | NPC | | SPPC | |
|---|---|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 | 2007 | 2006 |
| Balance at January 1 | $ 18,194 | $ 17,082 | $ 12,895 | $ 12,097 | $ 5,299 | $ 4,985 |
| Liabilities incurred in current period | 32,867 | - | 32,867 | - | - | - |
| Liabilities settled in current period | - | - | - | - | - | - |
| Accretion expense | 1,879 | 1,112 | 1,488 | 798 | 391 | 314 |
| Revision in estimated cash flows | 522 | - | (980) | - | 1,502 | - |
| Balance at December 31 | $ 53,462 | $ 18,194 | $ 46,270 | $ 12,895 | $ 7,192 | $ 5,299 |

The significant increase to NPC's ARO balance is primarily related to the Reid Gardner Generating Station. An adjustment of approximately $12 million was made to the original ARO costs due to revised estimates for the evaporative ponds. In addition, approximately $20 million was added to the ARO balance as a result of the Administrative Order on Consent between Nevada Division of Environmental Protection and NPC as discussed further in Note 13. Commitments and Contingencies.

**Cost of Removal**

In addition to the legal asset retirement obligations booked under SFAS 143 and FIN 47, the Utilities have accrued for the cost of removing non-legal retirement obligations of other electric and gas assets, in accordance with accepted accounting practices. The amounts of such accruals included in regulatory liabilities in 2007 are approximately $161.7 million and $129.6 million for NPC and SPPC, respectively. In 2006, the amounts were approximately $162.2 million and $121.3 million.

**Variable Interest Entities**

In December 2003, the FASB issued a revised Interpretation No. 46, "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 2003, SPR, NPC and SPPC adopted FIN 46 (R) for special purpose entities. In 2004, SPR, NPC and SPPC adopted FIN 46 (R) for all variable interest entities. To identify potential variable interests, management reviewed long term purchase power contracts, including contracts with qualifying facilities (QFs), jointly owned facilities and partnerships that are not consolidated. The Utilities identified seven QFs with long-term purchase power contracts that are variable interests. However, the Utilities are not required at this time to consolidate these QFs under the scope exception provided for in FIN 46 (R) due to the inability to obtain information necessary to (1) determine whether the entity is a variable interest entity, (2) determine whether the enterprise is the variable interest entity's primary beneficiary, or (3) perform the accounting required to consolidate the variable interest entity for which it is determined to be the primary beneficiary. The Utilities have requested financial information from these QFs but have not been successful in obtaining the information. The Utilities' maximum exposure to loss is limited to the cost of replacing these purchase power contracts if the QFs are unable to deliver power. However, the Utilities believe their exposure is mitigated as they would likely recover these costs through their deferred energy accounting mechanism. The Utilities have not identified any other significant variable interests that require consolidation as of December 31, 2007.

**Recent Pronouncements**

*SFAS 157*

In September 2006, the Financial Accounting Standards Board (FASB) issued Statement of Financial Accounting Standards (SFAS) No. 157, "Fair Value Measurement" ("SFAS 157"). SFAS 157 addresses the need for increased consistency in fair value measurements, defining fair value as the price that would be received to sell an asset or paid to transfer a liability in an orderly transaction between market participants at the measurement date. It also establishes a framework for measuring fair value and expands disclosure requirements. The provisions of SFAS 157 are effective for fiscal years beginning after November 15, 2007 and

interim periods within those fiscal years. SFAS 157 was effective for SPR and the Utilities beginning January 1, 2008. SPR and the Utilities do not expect the adoption of SFAS 157 to have a material impact on the consolidated financial statements.

*SFAS 159*

In February 2007, the FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities" ("SFAS 159"), which permits entities to choose to measure many financial instruments and certain other items at fair value. The objective of the statement is to improve financial reporting by providing entities with the opportunity to mitigate volatility in reported earnings caused by measuring related assets and liabilities differently without having to apply complex hedge accounting provisions. The provisions of SFAS 159 are effective for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years. SFAS 159 was effective for SPR and the Utilities beginning January 1, 2008. SPR and the Utilities do not expect the adoption of SFAS 159 to have a material impact on the consolidated financial statements.

## NOTE 2. SEGMENT INFORMATION

The Utilities operate three regulated business segments (as defined by SFAS 131, "Disclosure about Segments of an Enterprise and Related Information"); which are NPC electric, SPPC electric and SPPC natural gas service. Electric service is provided to Las Vegas and surrounding Clark County by NPC, and 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 thresholds for separate disclosure.

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 gross margin. Gross margin, which the Utilities calculate as operating revenues less fuel, purchased power, and deferred energy costs, provides a measure of income available to support the other operating expenses of the Utilities. Operating expenses are provided by segment in order to reconcile to operating income as reported in the consolidated financial statements. NPC's operating income for the year ended December 31, 2006 includes the reinstatement of deferred energy costs of $178.8 million and SPPC's operating income for the year ended December 31, 2007 includes deferred energy costs disallowed of $14.2 million, which are not reflected in their respective gross margin (dollars in thousands).

| December 31, 2007 | NPC Electric | SPPC Electric | SPPC Gas | SPPC Reconciling Eliminations[1] | SPPC Total | SPR Other | SPR Consolidated |
|---|---|---|---|---|---|---|---|
| Operating Revenues | $ 2,356,620 | $ 1,038,867 | $ 205,430 | | $ 1,244,297 | $ 43 | $ 3,600,960 |
| Energy Costs: | | | | | | | |
| Purchase Power | $ 688,606 | $ 348,299 | $ - | | $ 348,299 | | $ 1,036,905 |
| Fuel for power generation | $ 594,382 | $ 242,973 | $ - | | $ 242,973 | | $ 837,355 |
| Gas purchased for resale | $ - | $ - | $ 150,879 | | $ 150,879 | | $ 150,879 |
| Deferred energy costs - net | $ 233,166 | $ 63,873 | $ 10,763 | | $ 74,636 | | $ 307,802 |
| | $ 1,516,154 | $ 655,145 | $ 161,642 | | $ 816,787 | $ - | $ 2,332,941 |
| Gross Margin | $ 840,466 | $ 383,722 | $ 43,788 | | $ 427,510 | $ 43 | $ 1,268,019 |
| Deferred energy costs disallowed | $ - | | | | $ 14,171 | $ - | $ 14,171 |
| Other | $ 232,610 | | | | $ 142,348 | $ 4,488 | $ 379,446 |
| Maintenance | $ 67,482 | | | | $ 31,553 | $ - | $ 99,035 |
| Depreciation and amortization | $ 152,139 | | | | $ 83,393 | $ - | $ 235,532 |
| Taxes: | | | | | | | |
| Income taxes | $ 61,108 | | | | $ 29,991 | $ (15,944) | $ 75,155 |
| Other than income | $ 29,823 | | | | $ 20,097 | $ 193 | $ 50,113 |
| Operating Income | $ 297,304 | | | | $ 105,957 | $ 11,306 | $ 414,567 |
| Assets | $ 6,377,369 | $ 2,665,943 | $ 273,220 | $ 37,361 | $ 2,976,524 | $ 110,857 | $ 9,464,750 |
| Capital expenditures | $ 766,136 | $ 389,427 | $ 41,763 | | $ 431,190 | | $ 1,197,326 |

| December 31, 2006 | NPC Electric | SPPC Electric | SPPC Gas | SPPC Reconciling Eliminations[1] | SPPC Total | SPR Other | SPR Consolidated |
|---|---|---|---|---|---|---|---|
| Operating Revenues | $ 2,124,081 | $ 1,020,162 | $ 210,068 | | $ 1,230,230 | $ 1,639 | $ 3,355,950 |
| Energy Costs: | | | | | | | |
| Purchase Power | $ 764,850 | $ 344,590 | | | $ 344,590 | | $ 1,109,440 |
| Fuel for power generation | $ 552,959 | $ 247,626 | | | $ 247,626 | | $ 800,585 |
| Gas purchased for resale | $ - | $ - | $ 160,739 | | $ 160,739 | | $ 160,739 |
| Deferred energy costs - net | $ 92,322 | $ 47,043 | $ 6,947 | | $ 53,990 | | $ 146,312 |
| | $ 1,410,131 | $ 639,259 | $ 167,686 | | $ 806,945 | $ - | $ 2,217,076 |
| Gross Margin | $ 713,950 | $ 380,903 | $ 42,382 | | $ 423,285 | $ 1,639 | $ 1,138,874 |
| Reinstatement of deferred energy costs | $ (178,825) | | | | $ - | $ - | $ (178,825) |
| Other | $ 218,120 | | | | $ 141,350 | $ 7,728 | $ 367,198 |
| Maintenance | $ 61,899 | | | | $ 31,273 | $ - | $ 93,172 |
| Depreciation and amortization | $ 141,585 | | | | $ 87,279 | $ 11 | $ 228,875 |
| Taxes: | | | | | | | |
| Income taxes | $ 91,781 | | | | $ 23,570 | $ (23,780) | $ 91,571 |
| Other than income | $ 28,118 | | | | $ 19,796 | $ 172 | $ 48,086 |
| Operating Income | $ 351,272 | | | | $ 120,017 | $ 17,508 | $ 488,797 |
| Assets | $ 5,987,515 | $ 2,476,483 | $ 275,294 | $ 56,060 | $ 2,807,837 | $ 36,724 | $ 8,832,076 |
| Capital expenditures | $ 670,441 | $ 282,641 | $ 32,937 | | $ 315,578 | | $ 986,019 |

| December 31, 2005 | NPC Electric | SPPC Electric | SPPC Gas | SPPC Reconciling Eliminations[1] | SPPC Total | SPR Other | SPR Consolidated |
|---|---|---|---|---|---|---|---|
| Operating Revenues | $ 1,883,267 | $ 967,427 | $ 178,270 | | $ 1,145,697 | $ 1,278 | $ 3,030,242 |
| Energy Costs: | | | | | | | |
| Purchase Power | $ 963,888 | $ 352,098 | | | $ 352,098 | | $ 1,315,986 |
| Fuel for power generation | $ 277,083 | $ 233,653 | | | $ 233,653 | | $ 510,736 |
| Gas purchased for resale | $ - | $ - | $ 140,850 | | $ 140,850 | | $ 140,850 |
| Deferred energy costs - net | $ (45,668) | $ 8,110 | $ (749) | | $ 7,361 | | $ (38,307) |
| | $ 1,195,303 | $ 593,861 | $ 140,101 | | $ 733,962 | $ - | $ 1,929,265 |
| Gross Margin | $ 687,964 | $ 373,566 | $ 38,169 | | $ 411,735 | $ 1,278 | $ 1,100,977 |
| Other | $ 211,039 | | | | $ 131,901 | $ 20,862 | $ 363,802 |
| Maintenance | $ 52,040 | | | | $ 26,690 | $ - | $ 78,730 |
| Depreciation and amortization | $ 124,098 | | | | $ 90,569 | $ (5) | $ 214,662 |
| Taxes: | | | | | | | |
| Income taxes | $ 46,425 | | | | $ 26,038 | $ (33,278) | $ 39,185 |
| Other than income | $ 25,535 | | | | $ 20,233 | $ 152 | $ 45,920 |
| Operating Income | $ 228,827 | | | | $ 116,304 | $ 13,547 | $ 358,678 |
| Assets | $ 5,173,921 | $ 2,218,938 | $ 245,707 | $ 81,656 | $ 2,546,301 | $ 150,324 | $ 7,870,546 |
| Capital expenditures | $ 546,748 | $ 121,767 | $ 17,879 | | $ 139,646 | | $ 686,394 |

(1) The reconciliation of segment assets at December 31, 2007, 2006, and 2005 to the consolidated total includes the following unallocated amounts:

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| Cash | $ 23,807 | $ 53,260 | $ 53,024 |
| Other regulatory assets | — | — | 19,265 |
| Deferred charges-other | 13,554 | 2,800 | 9,367 |
| | $ 37,361 | $ 56,060 | $ 81,656 |

## NOTE 3. REGULATORY ACTIONS

### Pending Rate Cases

### Nevada Power Company

***NPC Fifth Amendment to 2006 Integrated Resource Plan (IRP)***

In December 2007, NPC filed its fifth amendment to its 2006 IRP requesting approval of three items: 1) a revised Demand Side Management plan; 2) a settlement agreement and new long-term power purchase agreement for approximately 50 MW of summer season capacity; and 3) a new long-term tolling agreement that will provide 570 MW of unit contingent summer season capacity.

### Sierra Pacific Power Company

***SPPC Nevada Gas BTER Filing***

In December 2007, SPPC filed an application for the authority to implement quarterly BTER adjustments for its natural gas and liquefied propane gas services. Approval of this application will not affect SPPC customers until the first notice of quarterly adjustment to the BTER is filed and implemented.

***SPPC Nevada 2007 General Rate Case***

In December 2007, SPPC filed its statutorily required electric GRC utilizing the hybrid methodology that was ratified by the 2007 Nevada Legislature. The hybrid methodology incorporates historical costs and certain projected costs. Under this new methodology, the projected costs must be known and measurable and must begin prior to the rate effective date.

In its GRC, SPPC is requesting the following:

- Increase in general rates by $110.8 million, approximately a 12.5% increase;
- Return on equity (ROE) and rate of return (ROR) of 11.5% and 8.73%, respectively;
- Authorization to recover the costs of major plant additions including a new 541 MW combined cycle generating plant and new transmission / distribution facilities; and
- Authorization to recover the projected operating and maintenance costs associated with the new combined cycle generating plant.

SPPC expects the new rates to be in effect on July 1, 2008.

### Other Pending Matters

***SPPC Nevada 2003 General Rate Case***

In its 2003 GRC, SPPC sought recovery of its unreimbursed costs associated with the Piñon Pine Coal Gasification Demonstration Project (the "Project"). The Project represented experimental technology tested pursuant to a Department of Energy (DOE) Clean Coal Technology initiative. Under the terms of the Project agreement, SPPC and DOE agreed to each fund 50% of construction costs of the Project. SPPC's participation in the Project had received PUCN approval as part of SPPC's 1993 integrated electric resource plan. While the conventional portion of the plant, a gas-fired combined cycle unit, was installed and performed as planned, the coal gasification unit never became fully operational. After numerous attempts to re-engineer the coal gasifier, the technology was determined to be unworkable.

In its order of May 25, 2004, the PUCN disallowed $43 million of unreimbursed costs associated with the Project. SPPC filed a Petition for Judicial Review with the Second Judicial District Court of Nevada (District Court) in June 2004 (CV04-01434). On January 25, 2006, the District Court vacated the PUCN's disallowance in SPPC's 2003 GRC and remanded the case back to the PUCN for further review as to whether the costs were justly and reasonably incurred (Order). On March 27, 2006, the PUCN appealed the Order to the Nevada Supreme Court (the "Supreme Court") and filed a motion to stay the Order pending the appeal to the Supreme Court. On June 12, 2006, the District Court granted PUCN's motion to stay the Order. The Supreme Court dismissed the appeal in September 2006. Requests for rehearing were denied in late December 2006, and on January 18, 2007 the matter was remitted back to the District Court, which, consistent with its January 25, 2006 order, remanded the matter back to the PUCN for further review.

A pre-hearing conference on this matter was held in June 2007, during which the parties were directed to file briefs on the scope of the issues they believe are before the PUCN. A second pre-hearing conference was held in August 2007 in which the PUCN determined the scope of the proceedings and set a procedural schedule. Hearings were held in early January 2008.

**Approved Rate Cases**

**Nevada Power Company**

***NPC 2007 Quarterly BTER Filings***

**November**

In November 2007, NPC filed an application to update the going forward BTER. NPC requested to decrease rates by $26.6 million, resulting in a 1% decrease. The PUCN approved the requested rate change with rates effective January 1, 2008.

**August**

In August 2007, NPC filed an application to update the going forward BTER. NPC requested to increase rates by $22.7 million, resulting in a 1% increase. The PUCN approved the requested rate change with rates effective October 1, 2007.

***NPC Fourth Amendment to 2006 Integrated Resource Plan (IRP)***

In July 2007, NPC filed its fourth amendment to its 2006 IRP requesting to expend $13.2 million on various transmission projects. In addition, NPC requested approval of various renewable energy purchase power agreements, totaling 139.5 megawatts (MWs), to be built over the next two to four years.

In November 2007, the PUCN approved the amendment to the IRP with the exception of the amounts to be spent on transmission projects. The PUCN requested that NPC further evaluate the total projected costs of the transmission project and re-submit the request.

***NPC 2007 Deferred Energy Rate Case and BTER Update***

In January 2007, NPC filed an application to create a new DEAA rate and to update the going forward BTER. NPC requested to decrease rates by $33.2 million, while recovering $75 million of deferred fuel and purchased power costs.

In March 2007, NPC filed an update to its going forward BTER which lowered the overall decrease in rates from $33.2 million to $5.9 million, resulting in less than a 1% decrease. NPC requested the amortization to begin June 1, 2007 and to continue for a 14-month period.

In June 2007, the PUCN approved a stipulation between the parties that resolved all the issues in this case with no material impact to the requested rate change with rates effective June 1, 2007.

***Material Amendments to NPC's 2006 Integrated Resource Plan***

In January 2007, NPC filed an amendment to its 2006 IRP requesting approval to expend $60 million to install new ultra-low emission burners on the four combustion turbines serving the combined cycle units at the Clark Generating Station.

In May 2007, the PUCN approved a stipulation pursuant to which NPC was authorized to expend $60 million to install the new ultra-low emission burners.

***NPC 2007 Western Energy Crisis Rate Case***

In January 2007, NPC filed an application to recover $83.6 million in deferred legal and settlement costs incurred to resolve claims associated with power supply contracts terminated during the Western Energy Crisis. This application requested to begin amortizing the costs over a four-year period beginning June 1, 2007.

In March 2007, the PUCN approved a negotiated settlement where NPC is authorized to recover the $83.6 million plus carrying charges over a three-year period beginning June 1, 2007, which differed from the four-year period requested in the application.

***NPC 2001 Deferred Energy Case***

In November 2001, NPC made a deferred energy filing 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 purchased fuel and power costs of $922 million and to spread the recovery of the deferred costs, together with a carrying charge, over a period of not more than three years.

In March 2002, the PUCN issued its Order on the 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 Bureau of Consumer Protection (BCP) both sought individual review of the PUCN Order in the First District Court of Nevada (the District Court). The District Court affirmed the PUCN's decision. Both NPC and the BCP filed Notices of Appeal with the Nevada Supreme Court.

In July 2006, the Supreme Court of Nevada issued a ruling reversing $178.8 million of the PUCN's disallowance which was part of the NPC's 2001 Deferred Energy Case. The decision directed the District Court to remand the matter back to the PUCN to determine the appropriate rate schedule.

In March 2007, the PUCN approved a stipulation that authorizes NPC to recover in rates $189.9 million over ten years beginning on June 1, 2007, with no additional carrying charges. The $189.9 million represents Nevada's jurisdictional portion of the $178.8 million disallowance plus carrying charges of $11.1 million from the date the costs were incurred to the date of disallowance by the PUCN.

***NPC 2006 General Rate Case***

In November 2006, NPC filed its statutorily required electric GRC and further updated the filing in February 2007. The filing requested an ROE and ROR of 11.4% and 9.39% and an increase to general revenues of $156.4 million.

The PUCN issued its order in May 2007, with rates effective as of June 1, 2007. The PUCN order resulted in the following significant items:

- increase in general rates of $120.1 million, a 5.66% increase;
- ROE and ROR of 10.7% and 9.06%, respectively;
- authorized 100% recovery of unamortized 1999 NPC / SPPC merger costs;
- authorized incentive rate making for Lenzie;
- authorized recovery of accumulated cost and savings, including the net book value of Mohave over an eight year period, see Note 1, Significant Accounting Policies for further discussion of Mohave.

**Sierra Pacific Power Company**

***SPPC 2007 Quarterly Electric BTER Filings***

**November**

In November 2007, SPPC filed an application to update the going forward BTER. SPPC requested to decrease rates by $7.7 million, resulting in approximately a 1% decrease. The PUCN approved the requested rate change with rates effective January 1, 2008.

**August**

In August 2007, SPPC filed an application to update the going forward BTER. SPPC requested to decrease rates by $17.4 million, resulting in a 1.85% decrease. The PUCN approved the requested rate change with rates effective October 1, 2007.

***SPPC 2007 Nevada Integrated Resource Plan***

In June 2007, SPPC filed its 2007 triennial IRP with the PUCN. The following are the key elements of the filing:

- requested approval for approximately $176 million in transmission projects;
- requested approval of four new demand side programs and to increase spending on seven existing demand side programs (total expenditures of $28.4 million). The demand side programs are intended to help customers use electricity more efficiently and also contribute to SPPC's Renewable Portfolio requirements; and

- requested approval to expend $16.5 million, an increase of $8.2 million, on the replacement of the diesel units in Kings Beach, California. The increase in costs is the result of higher material costs and the costs to meet the environmental requirements of the Tahoe Regional Planning Administration.

In December 2007, the PUCN approved the IRP with the exception of a transmission project estimated at $91 million. In connection with that transmission project, SPPC was ordered to investigate only the feasibility of permitting the project.

***SPPC 2007 Nevada Natural Gas and Propane Deferred Energy Rate Case BTER Update***

In May 2007, SPPC filed an application to create a new Deferred Energy Accounting Adjustment (DEAA) rate and to update the going forward BTER. SPPC requests to increase rates by $13.4 million, while recovering $900 thousand of deferred gas costs. This application requests an overall rate increase of 7.05%.

Subsequent to the filing, SPPC reduced its deferred gas costs by $2.3 million due to a re-allocation of cost between the gas and electric segments. As a result, SPPC updated its filing from recovering $900 thousand of deferred gas costs to a refund of $1.4 million to the customers. In addition, due to lower natural gas costs, SPPC updated its forecasts used in calculating the going forward BTER and its overall requested rate change went from an increase of $13.4 million to a decrease of $2.3 million.

In November 2007, the PUCN approved the revised rate change with rates effective December 1, 2007.

***SPPC 2006 Nevada Western Energy Crisis Rate Case***

In December 2006, SPPC filed an application to recover $22.6 million in deferred legal and settlement costs incurred to resolve claims arising from the Western Energy Crisis. This application requested an overall rate increase of 0.53% and to begin amortizing the costs over a four-year period beginning July 1, 2007.

In February 2007, SPPC entered into a stipulation pursuant to which SPPC replaced its request to implement rates on July 1, 2007 with a request to recover approximately $16.3 and $6.3 million, respectively, in deferred settlement and legal costs. SPPC further requested authority to recover carrying charges on the regulatory asset.

In November 2007, the PUCN authorized SPPC to establish a regulatory asset, including carrying charges, to recover $2.8 million of the legal costs. The recovery period was not established in this proceeding but will be determined in a later filing. As a result of this order and recognition of legal reserves and other adjustments in prior periods, SPPC recorded a $7.6 million expense (net of taxes) in the fourth quarter of 2007.

***SPPC 2006 Nevada Electric Deferred Energy Rate Case and BTER Update***

In December 2006, SPPC filed an application to create a new electric DEAA rate and to update the electric BTER. SPPC requested to decrease rates by $7.9 million, a decrease of 0.86%, while recovering $18.7 million of deferred fuel and purchased power costs. SPPC sought recovery using a symmetrical two-year amortization period beginning July 1, 2007.

In June 2007, the PUCN approved a stipulation between the parties that resolved all the issues in this case with no material impact to the requested rate change with rates effective July 1, 2007.

**FERC Matters**

**Nevada Power Company**

Based on the FERC's orders to date, NPC believes the recalculated energy prices for NPC sales to the California Independent System Operator (CAISO) and the bankrupt California Power Exchange (CALPX) would result in an approximate $19 million refund. The FERC has also allowed for energy sellers to provide cost justification in the event the recalculated energy prices fall below sellers' costs. NPC's developed and filed a cost based filing, which justified a $6 million reduction to the estimated refunds resulting in a $13 million refund.

The CAISO and CALPX currently owe NPC approximately $19 million for power delivered during the same timeframe and a $13 million refund would reduce the amount owed to Nevada Power to $6 million. NPC previously recorded a reserve against the $19 million receivable in 2001.

**Sierra Pacific Power Company**

Based on the FERC's orders to date, SPPC believes the recalculated energy prices for sales to the CAISO and CALPX during the October 2, 2000 to June 20, 2001 timeframe would result in a $4 million refund.

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

## NOTE 4. INVESTMENTS IN SUBSIDIARIES AND OTHER PROPERTY

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

### Sierra Pacific Resources

| | December 31, | |
|---|---|---|
| | 2007 | 2006 |
| Investment in Tuscarora Gas Transmission Company [1] | $ - | $ 590 |
| Cash Value-Life Insurance | 2,401 | 12,891 |
| Non-utility property of NEICO | 5,136 | 5,101 |
| Non-utility property of SPCOM | 10,000 | 10,000 |
| Property not designated for Utility use | 12,577 | 4,793 |
| Other non-utility property | 947 | 950 |
| | $ 31,061 | $ 34,325 |

(1) Tuscarora Gas Pipeline Company (TGPC), which is wholly owned by SPR, sold its interest in Tuscarora Gas Transmission Company during December 2006 for approximately $100 million. The gain on the sale of the investment was approximately $40.9 million after taxes. The remaining 1% interest in Tuscarora Gas Transmission Company was sold during December 2007 for approximately $1.9 million. The gain on the sale of the remaining investment was approximately $890 thousand after taxes.

### Nevada Power

| | December 31, | |
|---|---|---|
| | 2007 | 2006 |
| Cash Value-Life Insurance | $ 2,401 | $ 12,891 |
| Non-utility property of NEICO | 5,136 | 5,101 |
| Property not designated for Utility use | 12,007 | 4,184 |
| | $ 19,544 | $ 22,176 |

### Sierra Pacific Power

| | December 31, | |
|---|---|---|
| | 2007 | 2006 |
| Property not designated for Utility use | $ 570 | $ 609 |

## NOTE 5. JOINTLY OWNED FACILITIES

At December 31, 2007, NPC and SPPC owned the following undivided interests in jointly owned electric utility facilities:

| | % Owned | Plant in Service | Accumulated Depreciation | Net Plant in Service | Construction Work in Progress |
|---|---|---|---|---|---|
| **NPC** | | | | | |
| Navajo Facility | 11.3 | $245,437 | $134,731 | $110,706 | $953 |
| Reid Gardner No. 4 | 32.2 | 130,653 | 98,371 | 32,282 | 27,496 |
| Silverhawk | 75.0 | 235,716 | 38,372 | 197,344 | 23 |
| | | $611,806 | $271,474 | $340,332 | $28,472 |
| **SPPC** | | | | | |
| Valmy Facility | 50.0 | $306,540 | $184,491 | $122,049 | $8,210 |

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

Reid Gardner Unit No. 4 is owned by the California Department of Water Resources (67.8%) and NPC (32.2%). NPC is the operating agent. Contractually, NPC is entitled to receive 25 MW of base load capacity and 227 MW of peaking capacity. Operationally, Unit No. 4 subject to heat input limitations is rated at 252 MW, NPC is entitled to use 100% of the unit's peaking capacity for 1,500 hours each year and is entitled to 9.6% of the first 250 MW of capacity and associated energy. NPC's share of the operating expenses for this facility is included in the corresponding operating expenses in its Consolidated Statement of Operations.

NPC is the operator of the Silverhawk generating station, which is jointly owned with Southern Nevada Water Authority. NPC owns 75% and its share of direct operation and maintenance expense is included in its accompanying Consolidated Statement of Operations.

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 Statement of Operations.

## NOTE 6. LONG-TERM DEBT

As of December 31, 2007, 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 and thereafter are shown below (dollars in thousands):

| | NPC | SPPC | SPR Holding Co. and Other Subs. | SPR Consolidated |
|---|---|---|---|---|
| 2008 | $ 7,170 | $ 101,643 | $ - | $ 108,813 |
| 2009 | 22,218 | 600 | - | 22,818 |
| 2010 | 8,004 | - | - | 8,004 |
| 2011 | 369,924 | - | - | 369,924 |
| 2012 | 136,449 | 100,000 | 63,670 | 300,119 |
| | 543,765 | 202,243 | 63,670 | 809,678 |
| Thereafter | 2,005,750 | 973,250 | 460,539 | 3,439,539 |
| | 2,549,515 | 1,175,493 | 524,209 | 4,249,217 |
| Unamortized Premium (Discount) Amount | (12,732) | 10,700 | 964 | (1,068) |
| Total | $ 2,536,783 | $ 1,186,193 | $ 525,173 | $ 4,248,149 |

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 respective General and Refunding Mortgage bonds are issued.

### Nevada Power Company

*6.75% General and Refunding Mortgage Notes, Series R*

On June 28, 2007, NPC issued and sold $350 million of its 6.750% General and Refunding Mortgage Notes, Series R, due July 1, 2037. The Series R Notes were issued pursuant to a registration statement previously filed with the Securities and Exchange Commission. The net proceeds from the issuance were used to fund the purchase of the tendered Series G Notes (discussed below), repay amounts outstanding under NPC's revolving credit facility, and for general corporate purposes.

*Pollution Control Refunding Revenue Bonds, Series 2006, 2006A and 2006B*

In August 2006, on behalf of NPC, Clark County, Nevada (Clark County) issued $39.5 million aggregate principal amount of its Pollution Control Refunding Revenue Bonds, Series 2006, due January 2036. On the same date, on behalf of NPC, Coconino County, Arizona Pollution Control Corporation (Coconino County) issued $40 million aggregate principal amount of its Pollution Control Refunding Revenue Bonds, Series 2006A, due September 2032, and $13 million aggregate principal amount of its Pollution Control Refunding Revenue Bonds, Series 2006B, due March 2039.

In connection with the issuance of these Bonds, NPC entered into financing agreements with Clark County and Coconino County, pursuant to which Clark County and Coconino County loaned the proceeds from the sales of the bonds to NPC. NPC's payment obligations under the financing agreements are secured by NPC's General and Refunding Mortgage Notes, Series P.

The interest rates of the Bonds were initially determined by an auction. The method of determining the interest rate on the Bonds may be converted from time to time so that such Bonds would thereafter bear interest at a daily, weekly, flexible, auction or term rate as designated.

The proceeds of the offering were used to refund the following, all of which were previously issued for the benefit of NPC:

- $39.5 million principal amount of Clark County's Pollution Control Refunding Revenue Bonds, Series 1992B,
- $20 million principal amount of Coconino County's Pollution Control Revenue Bonds, Series 1996,
- $20 million principal amount of Coconino County's Pollution Control Revenue Bonds, Series 1997B, and
- $13 million principal amount of Coconino County's Pollution Control Revenue Bonds, Series 1995E.

*General and Refunding Mortgage Notes, Series O*

In May 2006, NPC issued and sold $250 million in aggregate principal amount of 6.5% General and Refunding Mortgage Notes, Series O, due 2018. The Series O Notes were issued with registration rights. Proceeds of the offering, together with available cash, were utilized to:

- fund the early redemption of $78 million aggregate principal amounts of NPC's 7.2% Industrial Development Revenue Bonds, Series 1992 C, due 2022,
- fund the early redemption, in June 2006, of approximately $72.2 million aggregate principal amount of NPC's 7.75% Junior Subordinated Debentures due 2038 (when the debentures were repaid upon redemption, the proceeds from the repayment were used to simultaneously redeem an equal amount of the 7.75% Cumulative Quarterly Preferred Securities of NVP Capital III, a wholly-owned subsidiary of NPC),
- repay amounts outstanding under NPC's revolving credit facility.

In June 2006, NPC issued an additional $75 million in aggregate principal amount of its 6.5% General and Refunding Mortgage Notes, Series O, as part of the same series as the original Series O Notes. The aggregate principal amount of 6.5% General and Refunding Mortgage Notes, Series O, due 2018, outstanding is $325 million as of December 31, 2006. The proceeds from the second issuance, along with the proceeds from an offering of $120 million of NPC's 6.65% General and Refunding Mortgage Notes, Series N, due 2036 (described below) were used to pay the total consideration for the tender offer for the 10.875% General and Refunding Mortgage Notes, Series E, described below.

*General and Refunding Mortgage Notes, Series N*

In April 2006, NPC issued and sold $250 million of its 6.65% General and Refunding Mortgage Notes, Series N, due April 2036. The Series N Notes were issued with registration rights. Proceeds of the offering, together with available cash, were utilized to:

- fund the early redemption of $35 million aggregate principal amount of NPC's 8.50% Series Z First Mortgage Bonds due 2023 plus approximately $1 million of associated redemption premiums,
- fund the early redemption of $105 million aggregate principal amount of 6.70% Industrial Development Revenue Bonds, due 2022, and
- fund the early redemption of approximately $122.5 million aggregate principal amount of NPC's 8.20% Junior Subordinated Debentures due 2037 (when the debentures were repaid upon redemption, the proceeds from the repayment were used to simultaneously redeem an equal amount of the 8.20% Cumulative Quarterly Preferred Securities of NVP Capital I, a wholly-owned subsidiary of NPC).

In June 2006, NPC issued an additional $120 million in aggregate principal amount of its 6.65% General and Refunding Mortgage Notes, Series N, as part of the same series as the original Series N Notes. The aggregate principal amount of 6.65% General and Refunding Mortgage Notes, Series N, due 2036, outstanding is $370 million as of December 31, 2006. The proceeds from the second issuance, along with the proceeds from an offering of $75 million of NPC's 6.5% General and Refunding Mortgage Notes, Series O, due 2018 (described above) were used to pay the total consideration for the tender offer on the 10.875% General and Refunding Mortgage Notes, Series E, described below.

*General and Refunding Mortgage Notes, Series M*

In January 2006, NPC issued and sold $210 million of its 5.95% General and Refunding Mortgage Notes, Series M, due March 2016. The Series M Notes were issued with registration rights. In February 2006 the net proceeds of the issuance plus available cash were used to repay $210 million of amounts outstanding under NPC's revolving credit facility, which were borrowed to finance the purchase of a 75% ownership interest in the Silverhawk Generating Facility.

*Revolving Credit Facility*

In November 2005, NPC amended and restated its existing secured $350 million revolving credit facility, maturing in October 2007, reducing the fees on both the unused portion of the facility and on the amounts borrowed, increasing the size of the facility to $500 million, extending the maturity to November 2010 and changing the Administrative Agent for the facility to Wachovia Bank, National Association. The rate for outstanding loans and/or letters of credit under the revolving credit facility will be at either an applicable base rate (defined as the higher of the Prime rate and the Federal Funds rate plus one-half of one percent) or a Eurodollar

rate plus a margin that varies based upon NPC's credit rating by at least two of the three rating agencies: Standard & Poor's ("S&P"), Moody's Investors Service, Inc. ("Moody's") and Fitch Ratings Ltd. ("Fitch"). Currently, the base rate is Prime, and NPC's applicable base rate margin is zero. The Eurodollar margin is 0.75%.

In April 2006, NPC increased the size of the credit facility to $600 million. The facility provides additional liquidity for increased commodity prices and temporary bridge financing of capital expenditures. As of December 31, 2007, NPC had $4.9 million of letters of credit outstanding and had no borrowings outstanding under the revolving credit facility. As of February 22, 2008, NPC had $5.1 million of letters of credit outstanding and had no amounts borrowed under the revolving credit facility.

The NPC Credit Agreement contains two financial maintenance covenants. The first requires that NPC maintain a ratio of consolidated indebtedness to consolidated capital, determined as of the last day of each fiscal quarter, not to exceed 0.68 to 1. The second requires that NPC maintain a ratio of consolidated cash flow to consolidated interest expense, determined as of the last day of each fiscal quarter for the period of four consecutive fiscal quarters, not to be less than 2.0 to 1. As of December 31, 2007, NPC was in compliance with these covenants.

The NPC Credit Agreement provides for an event of default if there is a failure under NPC's other financing agreements to meet certain payment terms or to observe other covenants that would result in an acceleration of payments due.

The NPC Credit Agreement places certain restrictions on debt incurrence, liens and dividends. These restrictions are discussed in Note 8, Debt Covenant and Other Restrictions.

*Other Redemptions*

*General and Refunding Mortgage Notes, Series G*

In June 2007, NPC settled its cash tender offer for its 9.00% General and Refunding Mortgage Notes, Series G, due 2013. Those holders who tendered their notes were entitled to receive a purchase price of $1,079.75 per $1,000 principal amount of Series G Notes. Approximately $210.3 million of the $227.5 million Series G Notes outstanding were validly tendered and accepted by NPC. As of December 31, 2007, approximately $17.2 million aggregate principal amount of the 9.00% General and Refunding Mortgage Bonds remain outstanding.

In July 2005, NPC redeemed $122.5 million aggregate principal amount of its 9% General and Refunding Mortgage Notes, Series G, due 2013. This redemption constituted 35% of the principal amount outstanding. The Series G Notes were redeemed at a redemption price equal to $1,090.00 for each $1,000 note redeemed for a redemption premium in excess of the principal amount of approximately $11 million. In accordance with SFAS 71, Accounting for the Effects of Certain Types of Regulation, the redemption premium to redeem the debt will be amortized over the original term of the debt.

**Sierra Pacific Power Company**

*6.75% General and Refunding Mortgage Notes, Series P*

On June 28, 2007, SPPC issued and sold $325 million of its 6.750% General and Refunding Mortgage Notes, Series P, due July 1, 2037. The Series P Notes were issued pursuant to a registration statement previously filed with the Securities and Exchange Commission. The net proceeds from the issuance were used to fund the purchase of the tendered Series A Notes (discussed below), repay amounts outstanding under SPPC's revolving credit facility and for general corporate purposes.

*Washoe County Water Facilities Refunding Revenue Bonds*

On April 27, 2007, on behalf of SPPC, Washoe County, Nevada (Washoe County) issued $80 million aggregate principal amount of its Water Facilities Refunding Revenue Bonds, Series 2007A and B, due March 1, 2036 (the "Water Bonds").

In connection with the issuance of the Water Bonds, SPPC entered into financing agreements with Washoe County, pursuant to which Washoe County loaned the proceeds from the sales of the Water Bonds to SPPC. SPPC's payment obligations under the financing agreements are secured by SPPC's General and Refunding Mortgage Notes, Series O.

The Water Bonds initial rates, as determined by auction on April 25, 2007, were 3.85%. The method of determining the interest rate on the Water Bonds may be converted from time to time so that such Bonds would thereafter bear interest at a daily, weekly, flexible, auction or term rate as designated.

The proceeds of the offerings were used to refund the $80 million aggregate principal amount of 5.00% Washoe County Water Facilities Revenue Bonds, Series 2001.

*Pollution Control and Gas and Water Facilities Refunding Revenue Bonds, Series 2006, 2006A, 2006B and 2006C*

In November 2006, on behalf of SPPC, Humboldt County, Nevada (Humboldt County) issued $49.75 million aggregate principal amount of its Pollution Control Refunding Revenue Bonds, Series 2006, due October 2029. On the same date, on behalf of SPPC, Washoe County, Nevada (Washoe County) issued $58.7 million aggregate principal amount of it Gas Facilities Refunding Revenue Bonds, Series 2006A, due August 2031; $75 million aggregate principal amount of its Water Facilities Refunding Revenue Bonds, Series 2006B, due March 2036; and $84.8 million aggregate principal amount of its Gas and Water Facilities Refunding Revenue Bonds, Series 2006C, due March 2036.

In connection with the issuance of these Bonds, SPPC entered into financing agreements with Humboldt County and Washoe County, pursuant to which Humboldt County and Washoe County loaned the proceeds from the sales of the bonds to SPPC. SPPC's payment obligations under the financing agreements are secured by SPPC's General and Refunding Mortgage Notes, Series N.

The interest rates of the Bonds were initially determined by an auction. The method of determining the interest rate on the Bonds may be converted from time to time so that such Bonds would thereafter bear interest at a daily, weekly, flexible, auction or term rate as designated.

The proceeds of the offerings were used to refund the following, all of which were previously issued for the benefit of SPPC:

- $17.5 million principal amount of 6.65% Washoe County's Gas Facilities Refunding Revenue Bonds, Series 1987
- $20 million principal amount of 6.55% Washoe County's Gas Facilities Refunding Revenue Bonds, Series 1990
- $21.2 million principal amount of 6.70% Washoe County's Gas Facilities Refunding Revenue Bonds, Series 1992
- $75 million principal amount of 6.65% Washoe County's Water Facilities Refunding Revenue Bonds, Series 1987
- $45 million principal amount of 6.30% Washoe County's Gas and Water Facilities Refunding Revenue Bonds, Series 1987
- $30 million principal amount of 5.90% Washoe County's Gas and Water Facilities Refunding Revenue Bonds, Series 1993B
- $9.8 million principal amount of 5.90% Washoe County's Water Facilities Refunding Revenue Bonds, Series 1993A
- $39.5 million principal amount of 6.55% Humboldt County's Pollution Control Refunding Revenue Bonds, Series 1987
- $10.25 million principal amount of 6.30% Humboldt County's Pollution Control Refunding Revenue Bonds, Series 1992A

*Humboldt County Pollution Control Refunding Revenue Bonds*

In October 2006, the 6.35% Humboldt County Pollution Control Refunding Revenue Bonds, Series 1992B, due August 2022, in the amount of $1 million were redeemed at 100% of the stated principal amount, plus accrued interest.

*General and Refunding Mortgage Notes, Series M*

In March 2006, SPPC issued and sold $300 million of its 6.00% General and Refunding Mortgage Notes, Series M, due May 2016. The Series M Notes were issued with registration rights. Proceeds of the offering were used to repay $173 million borrowed under the revolving credit facility that was utilized to:

- fund the early redemption of $110 million aggregate principal amount of SPPC's Collateralized Medium Term 6.95% to 8.61% Series A Notes due 2022;
- fund the early redemption of $58 million aggregate principal amount of SPPC's Collateralized Medium Term 7.10% to 7.14% Series B Notes due 2023;
- pay for maturing debt of $30 million aggregate principal amount of SPPC's Collateralized Medium Term 6.81% to 6.83% Series C Notes due 2006;
- pay for $51 million in connection with the redemption of $50 million of SPPC's Series A Preferred Stock (two million shares of stock were redeemed at a redemption price per share of $25.683, plus accrued dividends to the redemption date of $0.4875 per share); and
- pay for maturing debt of $20 million aggregate principal amount of SPPC's Collateralized Medium Term 6.62% to 6.65% Series C Notes due 2006.

*Revolving Credit Facility*

In November 2005, SPPC amended and restated its existing secured $50 million revolving credit facility, maturing in October 2007, reducing the fees on both the unused portion of the facility, and on the amounts borrowed, increasing the size of the facility to $250 million, extending the maturity to November 2010 and changing the Administrative Agent for the facility to Wachovia Bank, National Association. The rate for outstanding loans and/or letters of credit under the revolving credit facility will be at either an applicable base rate (defined as the higher of the Prime rate and the Federal Funds rate plus one-half of one percent) or a Eurodollar rate, plus a margin that varies based upon SPPC's credit rating by at least two of the three rating agencies (S&P, Moody's and Fitch). Currently, the base rate is Prime and SPPC's applicable base rate margin is zero. The current Eurodollar margin is 0.75%.

In April 2006, SPPC increased the size of its credit facility to $350 million. The facility provides additional liquidity for increased commodity prices and temporary bridge financing of capital expenditures. As of December 31, 2007, SPPC had $20.5 million of letters of credit outstanding and had no amounts borrowed under the revolving credit facility. As of February 22, 2008, SPPC had $19.5 million of letters of credit and had no amounts borrowed under the revolving credit facility.

The SPPC Credit Agreement contains two financial maintenance covenants. The first requires that SPPC maintain a ratio of consolidated indebtedness to consolidated capital, determined as of the last day of each fiscal quarter, not to exceed 0.68 to 1. The second requires that SPPC maintain a ratio of consolidated cash flow to consolidated interest expense, determined as of the last day of each fiscal quarter for the period of four consecutive fiscal quarters, not to be less than 2.0 to 1. As of December 31, 2007, SPPC was in compliance with these covenants.

The SPPC Credit Agreement provides for an event of default if there is a failure under SPPC's other financing agreements to meet certain payment terms or to observe other covenants that would result in an acceleration of payments due.

The SPPC Credit Agreement, similar to SPPC's Series H Notes, places certain restrictions on debt incurrence, liens and dividends. These limitations are discussed in Note 8, Debt Covenant and Other Restrictions.

*Other Redemptions*

*Tender Offer for General and Refunding Mortgage Notes, Series A*

On June 28, 2007, SPPC settled its cash tender offer, which commenced on June 15, 2007 and expired on June 22, 2007, for its 8.00% General and Refunding Mortgage Notes, Series A, due 2008. Those holders who tendered their notes by the expiration date were entitled to receive a purchase price of $1,022.10 per $1,000 principal amount of Series A Notes. Approximately $220.8 million of the $320 million Series A Notes outstanding were validly tendered and accepted by SPPC. As of December 31, 2007, $99.2 million aggregate principal amount of the 8.00% General and Refunding Mortgage Notes remain outstanding.

**Sierra Pacific Resources**

*Debt Repurchase*

In December 2007, SPR repurchased approximately $10.5 million of the 7.803% Senior Notes and approximately $14.5 million of the 6.75% Senior Notes. The total consideration was approximately $26 million (which included a premium and accrued interest), and was paid from SPR's cash on hand. As of December 31, 2007, the outstanding balances for the 7.803% Senior Notes and 6.75% Senior Notes were $63.7 million and $210.5 million, respectively.

*Tender Offer*

In November 2006, SPR commenced tender offers for up to $110 million aggregate principal amount of its 7.803% Senior Notes due 2012, its 8.625% Senior Notes due 2014, and its 6.75% Senior Notes due 2017. Each of the offers was conditioned on SPR purchasing no more than an aggregate principal amount of $110 million of all notes validly tendered. To meet this condition, SPR terminated the offer for the 6.75% Notes. In December 2006 approximately $25 million of the 7.803% Senior Notes outstanding, and approximately $85 million of the 8.625% Senior Notes outstanding were validly tendered and accepted by SPR. The total consideration paid was approximately $120.6 million (which included an early tender premium and accrued interest).

*7.803% Senior Notes*

In May 2005, SPR issued $99.1 million aggregate principal amount of 7.93% Senior Notes, due 2007. These senior notes replaced the notes associated with the Premium Income Equity Securities (Old PIES), which were originally issued in November 2001. SPR successfully remarketed these notes in June 2005. In connection with the remarketing, the interest rate of the senior notes was reset to 7.803% per annum, effective on and after June 14, 2005. The remarketed senior notes will mature in June 2012. In December 2006, a portion of these Notes were tendered. (See Tender Offer and Debt Repurchase above).

*6.75% Senior Notes*

In August 2005, SPR conducted a private placement of $225 million 6.75% Senior Notes due 2017. The proceeds were used to repurchase approximately $141 million 7.93% Senior Notes associated with the Old PIES, pay approximately $54 million in premiums associated with the conversion of the 7.25% Notes and fund the associated fees and expenses; and to provide additional liquidity to SPR. (See Debt Repurchase above)

*8.625% Senior Notes*

In March 2004, SPR issued and sold $335 million 8.625% Senior Unsecured Notes due March 2014. The Senior Unsecured Notes, which were issued with registration rights, were exchanged for registered notes in October 2004. The proceeds of the issuance were used to fund the repurchase of approximately $174 million in principal amount of SPR's 8.75% Notes due 2005 at a price equal to approximately 107.225% of the principal amount thereof that were tendered pursuant to SPR's tender offer.

The balance of the net proceeds were used in May 2004 to legally extinguish the approximately $126 million of remaining principal amount of SPR's 8.75% Notes due 2005 which were not tendered, and to pay associated interest and fees and expenses associated with the tender offer and the Notes offering. The total cost to extinguish the debt was approximately $23.7 million consisting of tender fees, interest costs and unamortized debt issuance costs.

In December 2006, a portion of the 8.625% Senior Unsecured Notes were tendered (See Tender Offer above). As of December 31, 2007, $250 million aggregate principal amount of the 8.625% Senior Notes remain outstanding.

**Lease Commitments**

In 1984, NPC entered into a 30-year capital lease for its Pearson building with five-year renewal options beginning in year 2015. The fixed rental obligation for the first 30 years is $5.1 million per year. Also, NPC has a power purchase contract with Nevada Sun-Peak Limited Partnership. The contract contains a buyout provision for the facility at the end of the contract term in 2016. The facility is situated on NPC property. In 2007, NPC entered into a 20-year lease, with three 10 year renewal options, to occupy land and building for its Southern Operations Center. In accordance with SFAS 13, "Accounting for Leases", NPC accounts for the building portion of the lease as a capital lease and the land portion of the lease as an operating lease. NPC has not begun depreciating the property as it continues to construct leasehold improvements. NPC expects to transfer operations to the facilities in or around mid summer 2008. In 2007, the Utilities entered into Master leasing agreements of which various pieces of equipment qualify as capital leases. The remaining equipment is treated as operating leases. The lease term is for 7 years.

Minimum lease payments for capital leases as of December 31, 2007, were as follows (dollars in thousands):

| | | |
|---|---|---|
| 2008 | $ | 13,147 |
| 2009 | | 12,467 |
| 2010 | | 12,466 |
| 2011 | | 9,630 |
| 2012 | | 9,493 |
| Thereafter | | 42,178 |
| Total minimum lease payments | $ | 99,381 |
| Less amounts representing interest | $ | 37,950 |
| Present value of net minimum lease payments | $ | 61,431 |

## NOTE 7. FAIR VALUE OF FINANCIAL INSTRUMENTS

The December 31, 2007, 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, 2007, is estimated to be $2.6 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 $2.5 billion at December 31, 2006.

The total fair value of SPPC's consolidated long-term debt at December 31, 2007, is estimated to be $1.2 billion (excluding current portion) based on quoted market prices for the same or similar issues or on the current rates offered to SPPC for debt of the same remaining maturities. The total fair value (excluding current portion) was estimated to be $1.1 billion as of December 31, 2006.

The total fair value of SPR's consolidated long-term debt at December 31, 2007 is estimated to be $4.3 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 $4.1 billion as of December 31, 2006.

## NOTE 8. DEBT COVENANT AND OTHER RESTRICTIONS

*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. In 2007, NPC and SPPC paid $28.2 million and $14.2 million in dividends, respectively, to SPR. In January 2008, NPC and SPPC paid $10.8 million and $5.3 million, respectively, in dividends declared prior to December 31, 2007.

On February 8, 2008, NPC and SPPC declared a $14.0 million and $8.0 million dividend, respectively, to SPR, to be paid in March 2008.

Since NPC and SPPC are public utilities, they are subject to regulation by state utility commissions, which impose limits on investment returns or otherwise may impact the amount of dividends that the Utilities may declare and pay. In June 2007, the PUCN terminated the dividend restriction previously imposed by the PUCN in February 2006, which limited the combined amount of cash NPC and SPPC could pay to SPR to actual cash necessary to service SPR's debt for the year.

Certain debt agreements entered into by SPR and the Utilities contain covenants which set restrictions on certain payments, including the amount of dividends they may declare and pay, and restrict the circumstances under which such dividends may be declared and paid.

**Limits on Restricted Payments**

*Sierra Pacific Resources*

Dividends are considered periodically by SPR's Board of Directors and are subject to factors that ordinarily affect dividend policy, such as current and prospective earnings, current and prospective business conditions, regulatory factors, SPR's financial conditions and other matters within the discretion of the Board, as well as dividend restrictions set forth in SPR's debt. The Board will continue to review the factors described above on a periodic basis to determine if and when it is prudent to declare a dividend on SPR's Common Stock. There is no guarantee that dividends will be paid in the future, or that, if paid, the dividends will be paid at the same amount or with the same frequency as in the past. In September 2007 and in December 2007, SPR paid a cash dividend of $0.08 per share. In February 2008, SPR declared a cash dividend of $0.08 per share for common stock holders of record as of February 22, 2008. SPR had not paid a dividend since 2002.

Certain SPR debt agreements contain covenants that limit the amount of restricted payments, including dividends that may be made by SPR. However, as of December 31, 2007, SPR complied with all such covenants, and management does not believe that these covenants will materially affect SPR's ability to pay dividends.

*Dividend Restrictions Applicable to the Utilities*

Certain series of general and refunding mortgage notes issued by the Utilities contain restrictions on the amount of dividends the Utilities may declare and pay and restrict the circumstances under which such dividends may be declared and paid. However, as of December 31, 2007, the Utilities complied with all such covenants, and these covenants do not currently significantly restrict either Utility's ability to pay dividends. Although each Utility currently meets the conditions described above, a significant loss by either Utility could cause that Utility to be precluded from paying dividends to SPR until such time as that Utility again meets the coverage test. If the series of notes which contain these covenants are upgraded to investment grade by S&P, these restrictions will be suspended and will no longer be in effect so long as the applicable series of notes remain investment grade by both Moody's and S&P.

The revolving credit agreements of the Utilities contain similar restrictions on the amount of dividends that may be paid. However, those restrictions are currently suspended and will remain suspended so long as the respective Utility's secured debt is rated investment grade by at least two out of the three major rating agencies.

Additionally, the Utilities are subject to the provision of the Federal Power Act that states that dividends cannot be paid out of funds that are properly included in their capital account. Although the meaning of this provision is unclear, the Utilities believe that the Federal Power Act restriction, as applied to their particular circumstances, would not be construed or applied by the FERC to prohibit the payment of dividends for lawful and legitimate business purposes from current year earnings, or in the absence of current year earnings, from other/additional paid-in capital accounts. If, however, the FERC were to interpret this provision differently, the ability of the Utilities to pay dividends to SPR could be jeopardized.

**Ability to Issue Debt**

*Sierra Pacific Resources*

Certain debt of SPR places restrictions on debt incurrence, liens and dividends, unless, at the time the debt is incurred, the ratio of consolidated cash flow to fixed charges for SPR's most recently ended four quarter period on a pro forma basis is at least 2 to 1. Under this covenant restriction, as of December 31, 2007, SPR would be allowed to incur up to $1.1 billion of additional indebtedness on a consolidated basis.

Notwithstanding this restriction, under the terms of the debt, SPR would still be permitted to incur debt including, but not limited to, obligations incurred to finance property construction or improvement, certain intercompany indebtedness, or indebtedness incurred to finance capital expenditures, pursuant to the Utilities' respective integrated resource plans. NPC and SPPC would also be permitted to incur a combined total of up to $500 million in indebtedness and letters of credit under their respective revolving credit facilities.

If the debt containing these covenants is 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 remain investment grade by both Moody's and S&P.

*Nevada Power Company*

Certain debt of NPC places restrictions on debt incurrence, liens and dividends, 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. Under this covenant restriction, as of December 31, 2007, NPC would be allowed to incur $2.5 billion of additional indebtedness. However, due to the terms of the SPR debt described above, NPC's and SPPC's combined debt limit is restricted to the $1.1 billion of additional indebtedness SPR could incur on a consolidated basis.

Under the terms of NPC's debt, NPC would also be permitted to incur debt, including, but not limited to, obligations incurred to finance property construction or improvements, certain intercompany indebtedness, certain letters of credit indebtedness, or indebtedness incurred to finance capital expenditures, pursuant to NPC's 2006 Integrated Resource Plan.

If the debt containing these covenants is upgraded to investment grade by S&P, these restrictions will be suspended and will no longer be in effect so long as the applicable debt remains investment grade by both Moody's and S&P.

*Sierra Pacific Power Company*

Certain debt of SPPC places restrictions on debt incurrence, liens and dividends, unless, at the time the debt is incurred, the ratio of consolidated cash flow to fixed charges for SPPC's most recently ended four quarter period on a pro forma basis is at least 2 to 1. Under this covenant restriction, as of December 31, 2007, SPPC would be allowed to incur up to $920 million of additional indebtedness on a consolidated basis. However, due to the terms of the SPR debt described above, NPC's and SPPC's combined debt limit is restricted to the $1.1 billion of additional indebtedness SPR could incur on a consolidated basis.

Under the terms of SPPC's debt, SPPC would also be permitted to incur debt including, but not limited to, obligations incurred to finance property construction or improvements, certain intercompany indebtedness, certain letters of credit indebtedness, or indebtedness incurred to finance capital expenditures, pursuant to SPPC's 2004 Integrated Resource Plan.

If the debt containing these covenants is upgraded to investment grade by S&P, these restrictions will be suspended and will no longer be in effect so long as the applicable debt remains investment grade by both Moody's and S&P.

## NOTE 9. DERIVATIVES AND HEDGING ACTIVITIES

SPR, SPPC and NPC apply SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" ("SFAS 133"), as amended by SFAS 138, SFAS No. 149 and SFAS No. 155. As amended, SFAS 133 establishes accounting and reporting standards for derivatives instruments, including certain derivative instruments embedded in other contracts and for hedging activities. It 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 meets certain defined conditions and qualifies as an effective hedge. SFAS 133 also provides a scope exception for contracts that meet the normal purchase and sales criteria specified in the standard. The normal purchases and normal sales exception requires, among other things, physical delivery in quantities expected to be used or sold over a reasonable period in the normal course of business. Contracts that are designated as normal purchase and normal sales are accounted for under deferred energy accounting

and not recorded on the Consolidated Balance Sheets at fair value. A majority of the contracts entered into by the Utilities meet the criteria specified for this exception.

**Commodity Risk**

The energy supply function encompasses the reliable and efficient operation of the Utilities' generation, the procurement of all fuels and power and resource optimization (i.e., physical and economic dispatch) and is exposed to risks relating to, but not limited to, changes in commodity prices. SPR's and the Utilities' objective in using derivative instruments is to reduce exposure to energy price risk. Energy price risks result from activities that include the generation, procurement and marketing of power and the procurement and marketing of natural gas. Derivative instruments used to manage energy price risk from time to time may include: forward contracts, which involve physical delivery of an energy commodity; over-the-counter options with financial institutions and other energy companies, which mitigate price risk by providing the right, but not the requirement, to buy or sell energy related commodities at a fixed price; and swaps, which require the Utilities to receive or make payments based on the difference between a specified price and the actual price of the underlying commodity. These contracts assist the Utilities to reduce the risks associated with volatile electricity and natural gas markets.

**Interest Rate Risk**

In March 2007, SPPC entered into three forward-starting interest rate swap agreements, with an aggregate notional principal amount of $250 million, to manage the risk associated with changes in interest rates and the impact on future interest payments.

In June 2007, SPPC settled its three forward-starting interest rate swap agreements in connection with the issuance of $325 million of its 6.75% fixed rate General and Refunding Mortgage Notes, Series P, due 2037. SPPC received a payment of $11.3 million from the counterparty and recorded the amount as a premium on long term debt to be amortized over the life of the debt in accordance with regulatory accounting practices under SFAS No. 71, "Accounting for the Effects of Certain Types of Regulation" ("SFAS 71").

NPC entered into and settled an interest rate lock agreement in June 2007, in connection with the issuance of $350 million of its 6.75% fixed rate General and Refunding Mortgage Notes, Series R, due 2037. NPC made a payment to the counterparty of $546 thousand and recorded the amount as a discount on long term debt to be amortized over the life of the debt in accordance with regulatory accounting practices under SFAS 71.

**Risk Management Assets/Liabilities**

The following table shows the fair value of the open derivative positions recorded on the Consolidated Balance Sheets of SPR, NPC and SPPC and the related regulatory assets/liabilities that did not meet the normal purchase and normal sales exception criteria in SFAS 133. The fair values of the open derivative positions are determined using quoted exchange prices, external dealer prices and available market pricing curves. Due to deferred energy accounting treatment 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. This accounting treatment is intended to defer the recognition of mark-to-market gains and losses on energy commodity transactions until the period of settlement and to not recognize gains and losses on the Consolidated Statements of Income (dollars in millions):

| | December 31, 2007 | | | December 31, 2006 | | |
|---|---|---|---|---|---|---|
| | Fair Value | | | Fair Value | | |
| | SPR | NPC | SPPC | SPR | NPC | SPPC |
| Risk management assets - current | $ 22.3 | $ 16.1 | $ 6.2 | $ 27.3 | $ 16.4 | $ 10.9 |
| Risk management assets – non-current | 12.5 | 9.1 | 3.4 | 7.6 | 5.4 | 2.2 |
| Total risk management assets | 34.8 | 25.2 | 9.6 | 34.9 | 21.8 | 13.1 |
| Risk management liabilities- current | 39.5 | 27.0 | 12.5 | 123.1 | 84.7 | 38.4 |
| Risk management liabilities - non-current | 7.4 | 5.1 | 2.3 | 10.8 | 7.1 | 3.7 |
| Total risk management liabilities | 46.9 | 32.1 | 14.8 | 133.9 | 91.8 | 42.1 |
| Less prepaid electric and gas options | 13.9 | 10.2 | 3.7 | 23.9 | 13.9 | 10.1 |
| Total Risk Management Regulatory (Asset)/Liability – net[1] | $ (26.0) | $(17.1) | $ (8.9) | $ (122.9) | $ (83.9) | $ (39.1) |

[1] When amount is negative (loss) it represents a Risk Management Regulatory Asset, when positive (gain) it represents a Risk Management Regulatory Liability.

As a result of the nature of operations and the use of mark-to-market accounting for certain derivatives that do not meet the normal purchase and normal sales exception criteria, mark-to-market fair values will fluctuate. The Utilities cannot predict these fluctuations, but the primary factors that cause changes in the fair values are the number and size of the Utilities open derivative positions with its counterparties and the changes in forward commodity prices. The reduction of risk management liabilities as of December 31, 2007, as compared to December 31, 2006, is mainly due to decrease in option premiums paid in 2007 and favorable open derivative positions on natural gas options held by the Utilities to hedge energy price risk for their customers resulting from higher commodity prices for natural gas at December 31, 2007 relative to contract prices.

## NOTE 10. INCOME TAXES (BENEFITS)

### Sierra Pacific Resources

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

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| Provision (benefit) for income taxes | | | |
| Current | | | |
| Federal | $ 10,503 | $ 5,914 | $ 3,159 |
| State | 70 | - | - |
| Total current | 10,573 | 5,914 | 3,159 |
| Deferred | | | |
| Federal | 85,165 | 144,919 | 43,833 |
| State | 366 | 494 | 1,688 |
| Total deferred | 85531 | 145,413 | 45,521 |
| Amortization of excess deferred taxes | (2,226) | (2,315) | (2,123) |
| Amortization of investment tax credits | (6,323) | (3,407) | (3,439) |
| Total provision for income taxes | $ 87,555 | $ 145,605 | $ 43,118 |
| Income statement classification of provision (benefit) for income taxes | | | |
| Operating income | 75,155 | $ 91,571 | $ 39,185 |
| Other income | 12,400 | 54,034 | 3,933 |
| Total | $ 87,555 | $ 145,605 | $ 43,118 |

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):

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| Net Income applicable to common stock | $ 197,295 | $ 277,451 | $ 82,237 |
| Preferred stock dividend requirement | - | 2,341 | 3,900 |
| Subtotal | 197,295 | 279,792 | 86,137 |
| Total income tax expense (benefit) | 87,555 | 145,605 | 43,118 |
| Pretax income | 284,850 | 425,397 | 129,255 |
| Statutory tax rate | 35% | 35% | 35% |
| Federal income tax expense at statutory rate | 99,698 | 148,889 | 45,239 |
| Depreciation related to difference in costs basis for tax purposes | 2,970 | 4,709 | 4,559 |
| Allowance for funds used during construction - equity | (11,133) | (6,379) | (7,113) |
| Investment tax credit amortization | (6,322) | (3,407) | (3,439) |
| Goodwill | 2,742 | 2,600 | 2,230 |
| Research and development credit | (1,130) | (3,764) | - |
| Other – net | 730 | 2,957 | 1,642 |
| Provision for income taxes before effect of income tax settlements | $ 87,555 | $ 145,605 | $ 43,118 |
| Effective tax rate | 30.7% | 34.2% | 33.3% |

As a large corporate taxpayer, the SPR consolidated group's tax returns are examined by the IRS on a regular basis. The IRS has completed audits of SPR for the years 1997-2004, but Joint Committee on Taxation notification procedures are still pending.

SPR believes that it has adequately provided reasonable reserves for reasonable and foreseeable outcomes related to uncertain tax matters.

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

| | 2007 | 2006 |
|---|---|---|
| Deferred income tax assets | | |
| Net operating loss and credit carryovers | $ 52,925 | $ 227,834 |
| Employee benefit plans | 25,587 | 71,820 |
| Customer advances | 35,044 | 32,163 |
| Gross-ups received on contribution in aid of construction and customer advances | 31,060 | 31,113 |
| Deferred revenues | 4,069 | 1,586 |
| Reserves | 13,743 | 508 |
| Other | 22,232 | 22,128 |
| Subtotal | 184,660 | 387,152 |
| Deferred income tax assets associated with regulatory matters | | |
| Excess deferred income taxes | 12,886 | 15,111 |
| Unamortized investment tax credit | 15,559 | 18,964 |
| Subtotal | 28,445 | 34,075 |
| Total deferred income tax assets before valuation allowance | 213,105 | 421,227 |
| Valuation allowance | (588) | (732) |
| Total deferred income tax assets after valuation allowance | $ 212,517 | $ 420,495 |
| | | |
| Deferred income tax liabilities | | |
| Excess of tax depreciation over book depreciation | $ 509,161 | $ 540,338 |
| Deferred energy | 88,213 | 192,653 |
| Regulatory assets | 86,517 | 101,375 |
| Other | 70,113 | 64,791 |
| Subtotal | 754,004 | 899,157 |
| Deferred income tax liabilities associated with regulatory matters | | |
| Tax benefits flowed through to customers | 267,848 | 263,170 |
| Total deferred income tax liability | $ 1,021,852 | $ 1,162,327 |
| | | |
| Net deferred income tax liability | $ 569,932 | $ 512,737 |
| Net deferred income tax liability associated with regulatory matters | 239,403 | 229,095 |
| Total net deferred income tax liability | $ 809,335 | $ 741,832 |

The total 2006 net deferred income tax liability of $741,832 includes $5,950 of deferred tax liability associated with accumulated depreciation on the Mohave generating station, which, on the financial statements, is included in other regulatory assets.

SPR's balance sheets contain a net regulatory asset of $239.4 million at December 31, 2007 and $229.1 million at December 31, 2006. The regulatory asset consists of future revenue to be received from customers due to flow-through of the tax benefits of temporary differences and goodwill recognized from the merger of NPC and SPR. Offset against these amounts are future revenues to be refunded to customers (regulatory liabilities). The regulatory liabilities consist of temporary differences for liberalized depreciation at rates in excess of current rates and unamortized investment tax credits. The regulatory liability for temporary differences related to liberalized depreciation will continue to be amortized using the average rate assumption method required by the Tax Reform Act of 1986. The regulatory liability for temporary differences caused by the investment tax credit will be amortized ratably in the same fashion as the accumulated deferred investment credit.

As reflected in SPR's balance sheet (dollars in thousands):

| | 2007 | 2006 |
|---|---|---|
| Tax benefits flowed through to customers | | |
| Related to property | $ 115,045 | $ 106,175 |
| Related to goodwill | 152,803 | 156,995 |
| Regulatory tax asset | 267,848 | 263,170 |
| | | |
| Liberalized depreciation at rates in excess of current rates | 12,886 | 15,111 |
| Unamortized investment tax credits | 15,559 | 18,964 |
| Regulatory tax liability | 28,445 | 34,075 |
| Net regulatory tax asset | $ 239,403 | $ 229,095 |

SPR and its subsidiaries file a consolidated federal income tax return. Current income taxes are allocated based on SPR's and each subsidiaries' respective taxable income or loss and investment tax credits as if each subsidiary filed a separate return.

The following table summarizes as of December 31, 2007 the tax NOL and tax credit carryovers and associated carryover periods, and valuation allowance for amounts which SPR has determined that realization is uncertain (dollars in thousands):

| | Deferred Tax Asset | Valuation Allowance | Net Deferred Tax Asset | Expiration Period |
|---|---|---|---|---|
| Federal NOL | $ 20,992 | $ - | $ 20,992 | 2020-2023 |
| State NOLs | 127 | - | 127 | 2008-2013 |
| Research and development credit | 5,465 | | 5,465 | 2021-2025 |
| Alternative minimum tax credit | 25,241 | - | 25,241 | indefinite |
| Arizona coal credits | 1,100 | 588 | 512 | 2008-2012 |
| Total | $ 52,925 | $ 588 | $ 52,337 | |

At December 31, 2007, SPR has gross federal and state net operating loss carry-forwards of $60.0 million and $1.4 million, respectively.

Considering all positive and negative evidence regarding the utilization of SPR's deferred tax assets, it has been determined that SPR is more-likely-than-not to realize all recorded deferred tax assets, except the Arizona coal credits. As such, these Arizona coal credits represent the only valuation allowance that has been recorded as of December 31, 2007.

SPR and the Utilities adopted the provisions of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109" ("FIN 48") as of January 1, 2007. As a result of the implementation of FIN 48, SPR and the Utilities recognized approximately a $27.8 million increase in the liability for unrecognized tax benefits. A reconciliation of the beginning and ending amount of unrecognized tax benefits is as follows (dollars in thousands):

| | |
|---|---|
| Balance at January 1, 2007 | $ 27,766 |
| Additions based on tax positions related to the current year | 9,487 |
| Additions for tax positions of prior years | 5,052 |
| Reductions for tax positions of prior years | (17,289) |
| Settlements | - |
| Lapse of statute of limitations | - |
| Balance at December 31, 2007 | $ 25,016 |

SPR and the Utilities classify interest and penalties related to income taxes as interest and other expense, respectively. The total amount of unrecognized tax benefits as of December 31, 2007 is $25.0 million, of which $2.4 million would affect the effective tax rate if recognized. No interest or penalties have been accrued as of December 31, 2007. No significant increases or decreases to unrecognized tax benefits are expected within the next twelve months.

SPR and the Utilities file a consolidated U.S. federal income tax return. The U.S. federal jurisdiction is the only "significant" tax jurisdiction for the Company. In connection with the previous examination cycles, the statute of limitations for tax years 1997 through 2003 was extended to December 31, 2008. The audits of tax years 1997 through 2004 have been completed, but are pending Joint Committee on Taxation notification. Tax years 2004-2007 remain subject to federal tax examination. All earlier years are closed by statute.

**Nevada Power Company**

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

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| Provision (benefit) for income taxes | | | |
| Current | | | |
| Federal | $ 25,351 | $ 4,865 | $ 3,159 |
| State | - | - | - |
| Total current | 25,351 | 4,865 | 3,159 |
| Deferred | | | |
| Federal | 58,344 | 114,741 | 63,873 |
| State | (63) | 268 | (449) |
| Total deferred, net | 58,281 | 115,009 | 63,424 |
| Amortization of excess deferred taxes | (1,236) | (745) | (778) |
| Amortization of investment tax credits | (4,044) | (1,619) | (1,810) |
| Total provision for income taxes | $ 78,352 | $ 117,510 | $ 63,995 |
| Income statement classification of provision for income taxes | | | |
| Operating income | $ 61,108 | $ 91,781 | $ 46,425 |
| Other income | 17,244 | 25,729 | 17,570 |
| Total | $ 78,352 | $ 117,510 | $ 63,995 |

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):

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| Net income | $ 165,694 | $ 224,540 | $ 132,734 |
| Total income tax expense | 78,352 | 117,510 | 63,995 |
| Pretax income | 244,046 | 342,050 | 196,729 |
| Statutory tax rate | 35% | 35% | 35% |
| Federal income tax expense at statutory rate | 85,416 | 119,718 | 68,855 |
| Depreciation related to difference in cost basis for tax purposes | 1,291 | 2,192 | 1,880 |
| Allowance for funds used during construction - equity | (5,551) | (4,114) | (6,539) |
| Investment tax credit amortization | (4,044) | (1,619) | (1,810) |
| Goodwill | 1,732 | 1,646 | 1,386 |
| Research and development credit | (527) | (1,666) | - |
| Other - net | 35 | 1,353 | 223 |
| Provision for income taxes before effect of income tax settlements | $ 78,352 | $ 117,510 | $ 63,995 |
| Effective tax rate | 32.1% | 34.4% | 32.5% |

As a large corporate taxpayer, the SPR consolidated group's tax returns are examined by the IRS on a regular basis. The IRS has completed audits of NPC for the years 1997-2004, but Joint Committee on Taxation notification procedures are still pending. NPC believes that it has adequately provided reasonable reserves for reasonable and foreseeable outcomes related to uncertain tax matters.

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

| | 2007 | 2006 |
|---|---|---|
| Deferred income tax assets | | |
| Net operating loss and credit carryovers | $ 26,341 | $ 137,344 |
| Employee benefit plans | 13,940 | 29,997 |
| Customer advances | 20,611 | 21,014 |
| Gross-ups received on contributions in aid of construction and customer advances | 21,334 | 21,844 |
| Deferred revenues | 1,948 | 1,586 |
| Reserves | 10,633 | (4) |
| Other - net | 12,928 | 14,207 |
| Subtotal | 107,735 | 225,988 |
| Deferred income tax assets associated with regulatory matters | | |
| Excess deferred income taxes | 4,024 | 5,259 |
| Unamortized investment tax credit | 6,014 | 8,192 |
| Subtotal | 10,038 | 13,451 |
| Total deferred income tax assets before valuation allowance | 117,773 | 239,439 |
| Valuation allowance | (588) | (732) |
| Total deferred income tax assets after valuation allowance | $ 117,185 | $ 238,707 |
| | | |
| Deferred income tax liabilities | | |
| Excess of tax depreciation over book depreciation | $ 319,926 | $ 345,135 |
| Deferred energy | 98,342 | 171,113 |
| Regulatory assets | 65,038 | 59,092 |
| Other - net | 51,407 | 43,299 |
| Subtotal | 534,713 | 618,639 |
| Deferred income tax liabilities associated with regulatory matters | | |
| Tax benefits flowed through to customers | 165,257 | 153,471 |
| Total deferred income tax liability | $ 699,970 | $ 772,110 |
| | | |
| Net deferred income tax liability | $ 427,566 | $ 393,383 |
| Net deferred income tax liability associated with regulatory matters | 155,219 | 140,020 |
| Total net deferred income tax liability | $ 582,785 | $ 533,403 |

The total 2006 net deferred income tax liability of $533,403 includes $5,950 of deferred tax liability associated with accumulated depreciation on the Mohave generating station, which, on the financial statements, is included in other regulatory assets. Reference Note 1, Summary of Significant Accounting Policies, for further discussion of the Mohave Generating Station.

NPC's balance sheet contains a net regulatory asset of $155.2 million at December 31, 2007 and $140.0 million at December 31, 2006. The regulatory asset consists of future revenue to be received from customers due to flow-through of the tax benefits of temporary differences and goodwill recognized from the merger of NPC and SPR. Offset against these amounts are future revenues to be refunded to customers (regulatory liabilities). The regulatory liabilities consist of temporary differences for liberalized depreciation at rates in excess of current rates and unamortized investment tax credits. The regulatory liability for temporary differences related to liberalized depreciation will continue to be amortized using the average rate assumption method required by the Tax Reform Act of 1986. The regulatory liability for temporary differences caused by the investment tax credit will be amortized ratably in the same fashion as the accumulated deferred investment credit.

As reflected in NPC's balance sheet (dollars in thousands):

| | 2007 | 2006 |
|---|---|---|
| Tax benefits flowed through to customers | | |
| Related to property | $ 69,602 | $ 55,177 |
| Related to goodwill | 95,655 | 98,294 |
| Regulatory tax asset | 165,257 | 153,471 |
| | | |
| Liberalized depreciation at rates in excess of current rates | 4,024 | 5,259 |
| Unamortized investment tax credits | 6,014 | 8,192 |
| Regulatory tax liability | 10,038 | 13,451 |
| Net regulatory tax asset | $ 155,219 | $ 140,020 |

SPR and its subsidiaries file a consolidated federal income tax return. Current income taxes are allocated based on SPR's and each subsidiaries' respective taxable income or loss and investment tax credits as if each subsidiary filed a separate return.

The following table summarizes as of December 31, 2007 the NOL and tax credit carryovers and associated carryover periods, and valuation allowance for amounts which NPC has determined that realization is uncertain (dollars in thousands):

| Type of Carryforward | Deferred Tax Asset | Valuation Allowance | Net Deferred Tax Asset | Expiration Period |
|---|---|---|---|---|
| Alternative minimum tax credit | $ 25,241 | $ - | $ 25,241 | indefinite |
| Arizona coal credits | 1,100 | 588 | 512 | 2008-2012 |
| Total | $ 26,341 | $ 588 | $ 25,753 | |

Considering all positive and negative evidence regarding the utilization of NPC's deferred tax assets, it has been determined that NPC is more-likely-than-not to realize all recorded deferred tax assets, except for a portion of the Arizona coal credits. As such, these Arizona coal credits represent the only valuation allowance that has been recorded as of December 31, 2007.

SPR and the Utilities adopted the provisions of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109" ("FIN 48") as of January 1, 2007. As a result of the implementation of FIN 48, Nevada Power Company recognized approximately a $6.8 million increase in the liability for unrecognized tax benefits. A reconciliation of the beginning and ending amount of unrecognized tax benefits for Nevada Power Company is as follows (dollars in thousands):

| | |
|---|---|
| Balance at January 1, 2007 | $ 6,784 |
| Additions based on tax positions related to the current year | 8,918 |
| Additions for tax positions of prior years | 4,989 |
| Reductions for tax positions of prior years | (562) |
| Settlements | - |
| Lapse of statute of limitations | - |
| Balance at December 31, 2007 | $ 20,129 |

SPR and the Utilities classify interest and penalties related to income taxes as interest and other expense, respectively. The total amount of unrecognized tax benefits for Nevada Power Company as of December 31, 2007, is $20.1 million, of which $0.9 million would affect the effective tax rate if recognized. No interest or penalties have been accrued as of December 31, 2007. No significant increases or decreases to unrecognized tax benefits are expected within the next twelve months.

SPR and the Utilities file a consolidated U.S. federal income tax return. The U.S. federal jurisdiction is the only "significant" tax jurisdiction for the Company. In connection with the previous examination cycles, the statute of limitations for tax years 1997 through 2003 was extended to December 31, 2008. The audits of tax years 1997 through 2004 have been completed, but are pending Joint Committee on Taxation notification. Tax years 2004-2007 remain subject to federal tax examination. All earlier years are closed by statute.

**Sierra Pacific Power Company**

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

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| Provision (benefit) for income taxes | | | |
| Current | | | |
| Federal | $ 57,483 | $ 28,497 | $ 67,291 |
| State | 70 | - | - |
| Total current | 57,553 | 28,497 | 67,291 |
| Deferred | | | |
| Federal | (28,705) | 2,464 | (38,074) |
| State | 429 | 226 | 2,136 |
| Total deferred | (28,276) | 2,690 | (35,938) |
| Amortization of excess deferred taxes | (990) | (1,570) | (1,345) |
| Amortization of investment tax credits | (2,278) | (1,788) | (1,629) |
| Total provision for income taxes | $ 26,009 | $ 27,829 | $ 28,379 |
| Income statement classification of provision (benefit) for income taxes | | | |
| Operating income | $ 29,991 | $ 23,570 | $ 26,038 |
| Other income | (3,982) | 4,259 | 2,341 |
| Total | $ 26,009 | $ 27,829 | $ 28,379 |

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):

| | 2007 | 2006 | 2005 |
|---|---|---|---|
| Income from continuing operations | $ 65,667 | $ 57,709 | $ 52,075 |
| Total income tax expense (benefits) | 26,009 | 27,829 | 28,379 |
| Pretax income | 91,676 | 85,538 | 80,454 |
| Statutory tax rate | 35% | 35% | 35% |
| Federal income tax expense (benefit) at statutory rate | 32,087 | 29,938 | 28,159 |
| Depreciation related to difference in cost basis for tax purposes | 1,679 | 2,517 | 2,678 |
| Allowance for funds used during construction - equity | (5,582) | (2,265) | (574) |
| Investment tax credit amortization | (2,278) | (1,788) | (1,629) |
| Goodwill | 1,009 | 954 | 844 |
| Research and development credit | (603) | (2,097) | - |
| Other - net | (303) | 570 | (1,099) |
| Provision for income taxes | $ 26,009 | $ 27,829 | $ 28,379 |
| Effective tax rate | 28.4% | 32.5% | 35.3% |

As a large corporate taxpayer, the SPR consolidated group's tax returns are examined by the IRS on a regular basis. The IRS has completed audits of SPPC for the years 1997-2004, but Joint Committee on Taxation notification procedures are still pending. SPPC believes that it has adequately provided reasonable reserves for reasonable and foreseeable outcomes related to uncertain tax matters.

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

| | 2007 | 2006 |
|---|---|---|
| Deferred income tax assets | | |
| Net operating loss and credit carryforwards | $ 5,311 | $ 6,233 |
| Employee benefit plans | 8,327 | 39,191 |
| Customer advances | 14,432 | 11,149 |
| Gross-ups received on contributions in aid of construction and customer advances | 9,726 | 9,269 |
| Deferred revenues | 2,121 | - |
| Deferred energy | 10,130 | - |
| Reserves | 2,903 | 200 |
| Other | 9,034 | 7,761 |
| Subtotal | 61,984 | 73,803 |
| Deferred income tax assets associated with regulatory matters | | |
| Excess deferred income taxes | 8,862 | 9,852 |
| Unamortized investment tax credit | 9,545 | 10,772 |
| Subtotal | 18,407 | 20,624 |
| Total deferred income tax assets | $ 80,391 | $ 94,427 |
| | | |
| Deferred income tax liabilities | | |
| Excess of tax depreciation over book depreciation | $ 189,234 | $ 195,203 |
| Deferred energy | - | 21,540 |
| Regulatory assets | 20,446 | 41,346 |
| Other | 18,192 | 14,035 |
| Subtotal deferred tax liabilities | 227,872 | 272,124 |
| Deferred income tax liabilities associated with regulatory matters | | |
| Tax benefits flowed through to customers | 102,591 | 109,699 |
| Total deferred income tax liability | $ 330,463 | $ 381,823 |
| | | |
| Net deferred income tax liability | $ 165,889 | $ 198,321 |
| Net deferred income tax liability associated with regulatory matters | 84,184 | 89,075 |
| Total net deferred income tax liability | $ 250,073 | $ 287,396 |

SPPC's balance sheet contains a net regulatory asset of $84.2 million at December 31, 2007 and $89.0 million at December 31, 2006. The regulatory asset consists of future revenue to be received from customers due to flow-through of the tax benefits of temporary differences and goodwill recognized from the merger of NPC and SPR. Offset against these amounts are future revenues to be refunded to customers (regulatory liabilities). The regulatory liabilities consist of temporary differences for liberalized depreciation at rates in excess of current rates and unamortized investment tax credits. The regulatory liability for temporary differences related to liberalized depreciation will continue to be amortized using the average rate assumption method required by the Tax Reform Act of 1986. The regulatory liability for temporary differences caused by the investment tax credit will be amortized ratably in the same fashion as the accumulated deferred investment credit.

As reflected in SPPC's balance sheet (dollars in thousands):

| | 2007 | 2006 |
|---|---|---|
| Tax benefits flowed through to customers | | |
| Related to property | $ 45,443 | $ 50,998 |
| Related to goodwill | 57,148 | 58,701 |
| Regulatory tax asset | 102,591 | 109,699 |
| | | |
| Liberalized depreciation at rates in excess of current rates | 8,862 | 9,852 |
| Unamortized investment tax credits | 9,545 | 10,772 |
| Regulatory tax liability | 18,407 | 20,624 |
| Net regulatory tax asset | $ 84,184 | $ 89,075 |

SPR and its subsidiaries file a consolidated federal income tax return. Current income taxes are allocated based on SPR's and each subsidiaries' respective taxable income or loss and investment tax credits as if each subsidiary filed a separate return.

The following table summarizes as of December 31, 2007 the NOL and tax credit carryovers and associated carryover periods for SPPC (dollars in thousands):

| Type of Carryforward | Deferred Tax Asset | Valuation Allowance | Net Deferred Tax Asset | Expiration Period |
|---|---|---|---|---|
| Federal NOL | $ 5,184 | $ - | $ 5,184 | 2020-2023 |
| State NOL | 127 | - | 127 | 2010-2013 |
| Total | $ 5,311 | $ - | $ 5,311 | |

At December 31, 2007, SPPC has gross federal and state net operating loss carryforwards of $14.8 million and $1.4 million, respectively.

Considering all positive and negative evidence regarding the utilization of SPPC's deferred tax assets, it has been determined that the company is more-likely-than-not to realize all recorded deferred tax assets and therefore no valuation allowance has been recorded as of December 31, 2007.

SPR and the Utilities adopted the provisions of FASB Interpretation No. 48, "Accounting for Uncertainty in Income Taxes – an interpretation of FASB Statement No. 109" ("FIN 48") as of January 1, 2007. As a result of the implementation of FIN 48, Sierra Pacific Power Company recognized approximately a $4.4 million increase in the liability for unrecognized tax benefits. A reconciliation of the beginning and ending amount of unrecognized tax benefits for Sierra Pacific Power Company is as follows (dollars in thousands):

| | |
|---|---|
| Balance at January 1, 2007 | $ 4,403 |
| Additions based on tax positions related to the current year | 569 |
| Additions for tax positions of prior years | - |
| Reductions for tax positions of prior years | (542) |
| Settlements | - |
| Lapse of statute of limitations | - |
| Balance at December 31, 2007 | $ 4,430 |

SPR and the Utilities classify interest and penalties related to income taxes as interest and other expense, respectively. The total amount of unrecognized tax benefits for Sierra Pacific Power Company as of December 31, 2007 is $4.4 million, of which $1.1 million would affect the effective tax rate if recognized. No interest or penalties have been accrued as of December 31, 2007. No significant increases or decreases to unrecognized tax benefits are expected within the next twelve months.

SPR and the Utilities file a consolidated U.S. federal income tax return. The U.S. federal jurisdiction is the only "significant" tax jurisdiction for the Company. In connection with the previous examination cycles, the statute of limitations for tax years 1997 through 2003 was extended to December 31, 2008. The audits of tax years 1997 through 2004 have been completed, but are pending Joint Committee on Taxation notification. Tax years 2004-2007 remain subject to federal tax examination. All earlier years are closed by statute.

## NOTE 11. RETIREMENT PLAN AND POST-RETIREMENT BENEFITS

SPR has pension plans covering substantially all employees. Benefits are based on years of service and the employee's highest compensation for a period prior to retirement. SPR also has other postretirement plans which provide medical and life insurance benefits for certain retired employees. The following tables provide a reconciliation of benefit obligations, plan assets and the funded status of the plans. This reconciliation is based on a September 30 measurement date (dollars in thousands):

| | Pension Benefits | | Other Postretirement Benefits | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| **Change in benefit obligations** | | | | |
| Benefit obligation, beginning of year | $ 645,373 | $ 625,451 | $ 172,192 | $ 179,184 |
| Service cost | 22,901 | 23,033 | 2,680 | 3,533 |
| Interest cost | 39,420 | 36,627 | 10,088 | 10,283 |
| Plan Participants' contributions | - | - | 2,044 | 1,445 |
| Actuarial loss (gain) | (8,414) | (18,414) | 6,382 | (10,770) |
| Gross Benefits paid | (31,949) | (20,960) | (10,031) | (11,998) |
| less: federal subsidy on benefits paid | N/A | N/A | 596 | 515 |
| Administrative Expenses | (328) | (299) | - | - |
| Plan amendments | - | (65) | (28,804) | - |
| Plan amendments - Local 1245 Buy Down | - | - | (12,600) | - |
| Utility Discount adjustment | - | - | 6,545 | - |
| Death Benefit Obligation adjustment | - | - | 1,083 | - |
| Acquisitions/divestitures | - | - | | - |
| Special Termination Benefits | - | - | - | - |
| Curtailments | - | - | - | - |
| Settlements | 7,684 | - | - | - |
| Benefit obligation, end of year | $ 674,687 | $ 645,373 | $ 150,175 | $ 172,192 |

The accumulated benefit obligation for Pension Benefits at the end of 2007 and 2006 was $545 million and $526 million respectively.

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

| | Pension Benefits | | Other Postretirement Benefits | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| Discount rate | 6.30% | 6.00% | 6.25% | 6.00% |
| Rate of compensation increase | 4.50% | 4.50% | N/A | N/A |

In 2007, for measurement purposes, the assumed annual rate of increase in the per capita cost of covered health care benefits was 8%, grading down to 5% in 2014.

In selecting an assumed discount rate for fiscal year 2007 pension cost and for fiscal year-end 2007 disclosures, SPR's projected benefit payments were matched to the yield curve derived from a portfolio of over 500 high quality Aa bonds with yields within the 40th to 90th percentiles of these bond yields.

Assumed health care cost trend rates have a significant effect on the amounts reported for the health care plans. A one-percentage-point change in assumed health care cost trend rates would have the following effect:

| **Effect on the postretirement benefit obligation** | 2007 | 2006 |
|---|---|---|
| Effect of a 1-percentage point increase | $ 9,860 | $ 18,823 |
| Effect of a 1-percentage point decrease | $ (8,538) | $ (15,657) |

The following table shows the change in plan assets for 2007 and 2006. SPR contributions for other post-retirement benefits reflect funding and benefit payments made by SPR (dollars in thousands):

| | Pension Benefits | | Other Postretirement Benefits | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| **Change in plan assets** | | | | |
| Fair value of plan assets, beginning of year | $ 534,260 | $ 488,766 | $ 63,236 | $ 53,223 |
| Adjustment to beginning of year value | - | - | - | - |
| Actual return on plan assets | 73,483 | 34,424 | 7,613 | 8,015 |
| Employer contributions | 64,529 | 32,329 | 46,059 | 12,550 |
| Plan participants' contributions | - | - | 2,044 | 1,445 |
| Gross benefits paid | (31,949) | (20,960) | (10,031) | (11,998) |
| Acquisitions | - | - | - | - |
| Special termination benefits | - | - | - | - |
| Settlements | - | - | - | - |
| Expenses paid | (327) | (299 ) | - | - |
| Fair value of plan assets, end of year | $ 639,996 | $ 534,260 | $ 108,921 | $ 63,235 |

The asset allocation for SPR's pension plans at the end of 2007 and 2006, and the target allocation for 2008, by asset category, follows. The fair value of plan assets for these plans is $640 million and $534.2 million, at the end of 2007 and 2006, respectively. The expected long-term rate of return on these plan assets was 8.00% and 8.25% in 2007 and 2006, respectively.

| | Allocation Percentage of Plan Assets at Year End | | |
|---|---|---|---|
| **Asset Category** | 2008 | 2007 | 2006 |
| Equity securities | 60% | 60% | 60% |
| Debt securities | 40 | 40 | 39 |
| Other | - | - | 1 |
| Total | 100% | 100% | 100% |

The asset allocation for the other postretirement benefit plans at the end of 2007 and 2006, and target allocation for 2008, by asset category, follows. The fair value of plan assets for these plans is $108.9 million and $63.2 million at the end of 2007 and 2006, respectively. The asset values are determined using recorded closing sales on a national securities exchange. The expected long-term rate of return on these plan assets was 8.00% and 8.25% in 2007 and 2006, respectively.

| | Allocation Percentage of Plan Assets at Year End | | |
|---|---|---|---|
| **Asset Category** | 2008 | 2007 | 2006 |
| Equity securities | 60% | 60% | 60% |
| Debt securities | 40 | 40 | 39 |
| Other | - | - | 1 |
| Total | 100% | 100% | 100% |

SPR's investment strategy is to ensure the safety of the principal of the assets and obtain asset performance to meet the continuing obligations of the plan. SPR strives to maintain a reasonable and prudent amount of risk, and seeks to limit risk through diversification of assets. Also, SPR considers the ability of the plan to pay all benefit and expense obligations when due, and to control the costs of administering and managing the plan. SPR's investment guidelines prohibit investing the plan assets in real estate and SPR's own stock. Currently, the plan assets are invested in international and domestic equity securities, and fixed securities which include bonds.

The pension plan assets and other post retirement benefit assets included approximately $255 million and $37 million, respectively, of debt securities at year end. The majority of the debt securities are valued on either a mark to matrix or a mark to model basis. The value of these assets is determined by independent pricing services on behalf of asset managers. In the case of debt securities in the pension plan assets, the custodian also uses independent pricing services to verify the managers' valuation. Differences are reconciled on a monthly basis. The plan assets do not have significant exposure to sub prime mortgages.

The following table shows the funded status of each of the plans for 2007 and 2006 (dollars in thousands):

| | Pension Benefits | | Other Postretirement Benefits | |
|---|---|---|---|---|
| **Funded Status, end of year:** | 2007 | 2006 | 2007 | 2006 |
| Fair value of plan assets | $ 639,996 | $ 534,260 | $ 108,921 | $ 63,236 |
| Benefit obligations | (674,687) | (645,373) | (150,175) | (172,192) |
| Funded status | $ (34,691) | $ (111,113) | $ (41,254) | $ (108,956) |
| Unrecognized net actuarial (gain)/loss | - | - | - | - |
| Unrecognized prior service (credit)/cost | - | - | - | - |
| Unrecognized net transition (asset)/obligation | - | - | - | - |
| Contribution between measurement date and fiscal year end | 337 | 368 | - | - |
| Amount recognized, end of year | $ (34,354) | $ (110,745) | $ (41,254) | $ (108,956) |

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

| | Pension Benefits | | Other Postretirement Benefits | |
|---|---|---|---|---|
| **Amounts recognized in the balance sheet consist of:** | 2007 | 2006 | 2007 | 2006 |
| Noncurrent asset | $ - | $ - | $ - | $ - |
| Current liability | (6,381) | (1,482) | - | - |
| Noncurrent liability | (27,973) | (109,263) | (41,254) | (108,956) |
| Prepaid benefit cost | - | - | - | - |
| Accrued benefit cost | - | - | - | - |
| Additional minimum liability | - | - | - | - |
| Intangible asset | - | - | - | - |
| Accumulated other comprehensive income | - | - | - | - |
| Net amount recognized | $ (34,354) | $ (110,745) | $ (41,254) | $ (108,956) |

The following amounts would have been recognized in Accumulated Other Comprehensive Income, net of taxes, according to the provisions of SFAS 158, which the Company adopted in 2006. Since the Company is able to recover SFAS 87 and SFAS 106 expenses through rates, the amounts will be recorded as regulatory assets for pension plans under the provisions of SFAS 71.

| | Pension Benefits | | Other Postretirement Benefits | |
|---|---|---|---|---|
| **Amounts recognized in regulatory assets for pension plans:** | 2007 | 2006 | 2007 | 2006 |
| Net actuarial (gain)/loss | $ 95,800 | $ 101,674 | $ 61,136 | $ 102,413 |
| Prior service (credit)/cost | 10,958 | 12,587 | (33,910) | 1,107 |
| Transition (asset)/obligation | - | - | - | 5,436 |
| | $ 106,758 | $ 114,261 | $ 27,226 | $ 108,956 |

The estimated amounts that will be amortized from other regulatory assets and accumulated other comprehensive income into net periodic cost in 2008 are as follows:

| | Pension Benefits | Other Postretirement Benefits |
|---|---|---|
| Actuarial (gain)/loss | $ 4,747 | $ 4,596 |
| Prior service (credit)/cost | 2,040 | (3,830) |
| Transition (asset)/obligation | - | - |

At the end of 2007 and 2006, the projected benefit obligation, accumulated benefit obligation, and fair value of plan assets for pension plans with a projected benefit obligation in excess of plan assets, and pension plans with an accumulated benefit obligation in excess of plan assets, were as follows (dollars in thousands):

| | Projected Benefit Obligation Exceeds the Fair Value of Plan's Assets | | Accumulated Benefit Obligation Exceeds the Fair Value of Plan's Assets | |
|---|---|---|---|---|
| | 2007 | 2006 | 2007 | 2006 |
| Projected benefit obligation, end of year | $ 674,687 | $ 645,373 | $ 20,660 | $ 25,890 |
| Accumulated benefit obligation, end of year | - | - | 18,583 | 23,768 |
| Fair value of plan assets, end of year | 639,996 | 534,260 | - | - |

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

The expected cash flows for the plans are as follows (dollars in thousands):

| | Pension Benefits | Other Postretirement Benefits | |
|---|---|---|---|
| **Company contributions** | | | |
| 2008 (expected) | $ 1,881 | $ 352 | |
| | | Gross | Expected Federal Subsidy |
| **Expected benefit payments** | | | |
| 2008 | 25,890 | 8,405 | 283 |
| 2009 | 26,897 | 9,113 | 306 |
| 2010 | 28,807 | 9,577 | 324 |
| 2011 | 31,040 | 10,134 | 332 |
| 2012 | 33,527 | 10,592 | 341 |
| 2013-2017 | 215,141 | 58,841 | 1,749 |

The above benefit payments are obligations of the indicated plan, and reflect payments which do not include employee contributions. The expected benefit payment information that reflects the employee obligation is almost exclusively paid from plan assets. A small portion of the pension benefit obligation is paid from the plan sponsor's assets.

The components of net periodic pension and other postretirement benefit costs for the consolidated companies, SPPC and NPC are presented below (dollars in thousands):

**Sierra Pacific Resources, consolidated**

| | Pension Benefits | | | Other Postretirement Benefits | | |
|---|---|---|---|---|---|---|
| | 2007 | 2006 | 2005 | 2007 | 2006 | 2005 |
| Service cost | $ 22,901 | $ 23,033 | $ 18,481 | $ 2,680 | $ 3,533 | $ 3,281 |
| Interest cost | 39,420 | 36,627 | 32,248 | 10,088 | 10,283 | 9,858 |
| Expected return on plan assets | (41,895) | (40,729) | (36,167) | (5,182) | (4,919 ) | (3,862) |
| Amortization of: | | | | | | |
| Actuarial (gain)/loss | 7,211 | 9,778 | 6,454 | 3,413 | 4,614 | 3,782 |
| Prior service (credit)/cost | 1,629 | 1,892 | 1,714 | (225) | 122 | 63 |
| Transition (asset)/obligation | - | - | - | 484 | 969 | 969 |
| Curtailment (gain)/loss | - | - | - | - | - | - |
| Settlement (gain)/loss / Special termination charges | 4,441 | - | 723 | - | - | 11 |
| Total net benefit cost | $ 33,707 | $ 30,601 | $ 23,453 | $ 11,258 | $ 14,602 | $ 14,102 |

The average percentage of SPR net periodic costs capitalized during 2007, 2006 and 2005 was 34.7%, 35.5% and 34.1%, respectively.

**Nevada Power Company**

| | Pension Benefits | | | Other Postretirement Benefits | | |
|---|---|---|---|---|---|---|
| | 2007 | 2006 | 2005 | 2007 | 2006 | 2005 |
| Service cost | $ 13,092 | $ 12,900 | $ 10,328 | $ 1,079 | $ 1,052 | $ 887 |
| Interest cost | 18,977 | 17,466 | 15,064 | 2,178 | 2,105 | 1,977 |
| Expected return on plan assets | (19,000 ) | (18,265 ) | (16,025 ) | (1,232 ) | (1,079 ) | (832) |
| Amortization of: | | | | | | |
| Actuarial (gain)/loss | - | - | - | 729 | 940 | 758 |
| Prior service (credit)/cost | 1,430 | 1,677 | 1,499 | 606 | 122 | 63 |
| Transition (asset)/obligation | 3,429 | 4,636 | 2,995 | 485 | 969 | 969 |
| Curtailment (gain)/loss | - | - | - | - | - | - |
| Settlement (gain)/loss / Special termination charges | - | - | 723 | - | - | 11 |
| Total net benefit cost | $ 17,928 | $ 18,414 | $ 14,584 | $ 3,845 | $ 4,109 | $ 3,833 |

The average percentage of NPC net periodic costs capitalized during 2007, 2006 and 2005 was 38.8%, 39.0% and 37.3%, respectively.

**Sierra Pacific Power Company**

| | Pension Benefits | | | Other Postretirement Benefits | | |
|---|---|---|---|---|---|---|
| | 2007 | 2006 | 2005 | 2007 | 2006 | 2005 |
| Service cost | $ 8,553 | $ 8,989 | $ 7,470 | $ 1,542 | $ 2,417 | $ 2,264 |
| Interest cost | 19,100 | 18,224 | 16,526 | 7,844 | 8,114 | 7,793 |
| Expected return on plan assets | (21,969) | (21,617) | (19,418) | (3,823) | (3,715) | (2,929 ) |
| Amortization of: | | | | | | |
| Actuarial (gain)/loss | - | - | - | 2,663 | 3,646 | 2,994 |
| Prior service (credit)/cost | 212 | 212 | 212 | (831) | - | - |
| Transition (asset)/obligation | 3,467 | 4,880 | 3,320 | - | - | - |
| Curtailment (gain)/loss | - | - | - | - | - | - |
| Settlement (gain)/loss / Special termination charges | - | - | - | - | - | - |
| Total net benefit cost | $ 9,363 | $ 10,688 | $ 8,110 | $ 7,395 | $ 10,462 | $ 10,122 |

The average percentage of SPPC net periodic costs capitalized during 2007, 2006 and 2005 was 35.7%, 33.3% and 32.1%, respectively.

The weighted-average assumptions used to determine net periodic cost are as follows:

| | Pension Benefits | | | Other Postretirement Benefits | | |
|---|---|---|---|---|---|---|
| | 2007 | 2006 | 2005 | 2007 | 2006 | 2005 |
| Discount rate | 6.00% | 5.75% | 6.10% | 6.00% | 5.75% | 6.10% |
| Expected Return on Plan Assets | 8.00% | 8.25% | 8.25% | 8.00% | 8.25% | 8.25% |
| Rate of compensation increase | 4.50% | 4.50% | 4.50% | N/A | N/A | N/A |

For measurement purposes, a 9% annual rate of increase in the per capita cost of covered health care benefits was assumed for 2007. The rate was assumed to average to 5% 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 8.00% in 2008.

The assumed health care cost trend rate has a significant effect on the amounts reported. A one percentage point change in the assumed health care cost trend rate would have had the following effect:

| One percentage point change: | 2007 | 2006 | 2005 |
|---|---|---|---|
| Effect on total of service and interest cost components | | | |
| Effect of a 1-percentage point increase in health care trend | 1,476 | 1,669 | 1,872 |
| Effects of a 1-percentage point decrease in health care trend | (1,210) | (1,360) | (1,503) |

There were no significant transactions between the plan and the employer or related parties during 2007, 2006, or 2005.

## NOTE 12. STOCK COMPENSATION PLANS

At December 31, 2007, SPR had several stock-based compensation plans, which are described below.

SPR's executive long-term incentive plan for key management employees, which was approved by shareholders in May 2004, provides for the issuance of up to 7,750,000 of SPR's common shares to key employees through December 31, 2013. The plan permits the following types of grants, separately or in combination: nonqualified and qualified stock options, stock appreciation rights, restricted stock, performance units, performance shares and bonus stock. During 2007, SPR issued nonqualified stock options, restricted shares and performance shares under the long-term incentive plan.

### Non-Qualified Stock Options

Elected officers and key employees specifically designated by a committee of the Board of Directors are eligible to be awarded nonqualified stock options (NQSO's) based on the guidelines in the plan. These grants are at 100% of the then current fair market value and vest over different periods, as stated in the grant. These options have to be exercised within ten years of award and no earlier than one year from the date of grant. At the time of grant, rights to dividend equivalents may also be awarded.

The total number of nonqualifying stock options granted to all employees in 2007 was 411,036, which were issued at an option price not less than market value at the date of grant. Of this amount, 409,934 will vest over three years from the grant date at one-third per year. The remaining 1,102, granted on November 1, 2007, will vest over three years beginning on February 15, 2008. 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. The Committee also allows cashless exercises, subject to applicable securities law restrictions or other means consistent with the purpose of the plan and the applicable law.

A summary of the status of SPR's nonqualified stock option plan as of December 31, 2007, 2006, and 2005, and changes during the year is presented below:

| | 2007 | | 2006 | | 2005 | |
|---|---|---|---|---|---|---|
| Nonqualified Stock Options | Shares | Weighted-Average Exercise Price | Shares | Weighted-Average Exercise Price | Shares | Weighted-Average Exercise Price |
| Outstanding at beginning of year | 1,199,188 | $ 14.66 | 1,077,772 | $ 14.38 | 1,235,950 | $ 15.85 |
| Granted | 411,036 | $ 18.25 | 176,416 | $ 13.29 | 169,036 | $ 10.10 |
| Exercised | 312,639 | $ 14.82 | 55,000 | $ 5.69 | 28,000 | $ 6.85 |
| Forfeited | 3,188 | $ 19.97 | - | $ - | 299,214 | $ 18.73 |
| Outstanding at end of year | 1,294,397 | $ 15.77 | 1,199,188 | $ 14.66 | 1,077,772 | $ 14.38 |
| Options exercisable at year-end | 747,317 | $ 14.94 | 913,209 | $ 15.42 | 928,368 | $ 15.07 |
| Intrinsic value of options exercised | $ 1,381,976 | | $ 571,190 | | $ 147,240 | |
| Fair value of options vested | $ - | | $ 141,037 | | $ 36,750 | |
| Weighted-average grant date fair value of options granted [1]: | | | | | | |
| Average of all grants for: | | | | | | |
| 2007 | $6.27 | | | | | |
| 2006 | | | $4.82 | | | |
| 2005 | | | | | $5.52 | |

(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 2007, 2006 and 2005:

| Year of Option Grant | Average Dividend Yield | Average Expected Volatility | Average Risk-Free Rate of Return | Average Expected Life |
|---|---|---|---|---|
| 2007 | 0.00% | 24.23% | 4.41% | 6 years |
| 2006 | 0.00% | 27.06% | 4.51% | 6 years |
| 2005 | 0.00% | 39.56% | 2.32% | 10 years |

The following table summarizes information about nonqualified stock options outstanding at December 31, 2007:

| Year of Grant | Weighted Average Exercise Price | Options Outstanding | | Options Exercisable | |
|---|---|---|---|---|---|
| | | Number Outstanding at 12/31/07 | Remaining Contractual Life | Weighted Average Exercise Price | Number Vested and Exercisable at 12/31/07 |
| 1998 | $24.93 | 15,840 | <1 year | $24.93 | 15,840 |
| 1999 | $25.35 | 36,440 | 1 year | $25.35 | 36,440 |
| 2000 | $16.00 | 400,000 | 1.6 - 2 years | $16.00 | 400,000 |
| 2001 | $15.08 | 22,510 | 3 years | $15.08 | 22,510 |
| 2002 | $14.05 | 86,410 | 4 - 4.5 years | $14.05 | 86,410 |
| 2004 | $7.29 | 25,000 | 6.5 years | $7.29 | 25,000 |
| 2005 | $10.10 | 126,966 | 7.2 - 7.4 years | $10.10 | 87,125 |
| 2006 | $13.29 | 170,195 | 8.1 years | $13.29 | 73,992 |
| 2007 | $18.25 | 411,036 | 9.1 - 9.8 years | $18.25 | - |
| Weighted Average Remaining Contractual Life | | | 5.83 | | 3.55 |
| Intrinsic Value | $ 2,431,746 | | | $ 1,802,651 | |

Dividend equivalents were not granted for any of these awards.

**Performance Shares**

In 2007, 2006 and 2005, SPR granted performance shares in the following numbers and initial values:

| | 2/14/2007 | 2/7/2006 | 2/7/2005 |
|---|---|---|---|
| Shares Granted | 138,967 | 675,056 | 214,596 |
| Value per Share | $ 16.96 | $ 10.03 | $ 9.58 |

In 2007, 2006 and 2005, 138,967, 172,446 and 171,676 shares of stock, respectively, were granted to plan participants; the actual number of shares earned by each participant is dependent upon SPR achieving certain financial goals over three-year performance periods. The value of all performance share grants, if earned, will be equal to the market value of SPR's common shares as of the end of the performance periods. Sierra Pacific Resources, at its sole discretion, may pay earned performance shares in the form of cash or in shares, or a combination thereof. In 2007, according to the performance criteria established for each grant, 40,037 shares were deemed to have been earned and were issued.

In 2006, there were 2,610 special grant shares awarded, which were to be earned only upon the restoration of both the NPC and SPPC investment grade credit status within three years of the date of grant. The shares for this grant were earned and issued in 2007.

In August, 2006, upon the signing of an employment agreement for the Chief Executive Officer, a grant of 500,000 performance shares was issued according to the agreement. The grant requires the achievement of specific performance goals which were established in the agreement. The final determination and approval of the number of shares awarded is at the discretion of the Board of Directors and the Compensation Committee. In 2007 and 2006, 200,000 and 65,000 shares, respectively, were deemed to have been earned and were issued in the form of cash.

There were 42,920 special grant shares awarded in 2005, which were to be earned only upon the restoration of both the NPC and SPPC investment grade credit status within three years of the date of grant. These shares were earned and issued in 2007.

SPR adopted SFAS No. 123R, “Share Based Payment” (“SFAS 123R”) in 2006, and according to the requirements set forth in that standard, recognized expense in 2007 and 2006 related to performance shares. For purposes of determining expense for those years, the compensation cost has been estimated using a lattice binomial pricing model with the following assumptions used for 2007 and 2006:

| Year | Average Dividend Yield | Average Expected Volatility | Average Risk-Free Rate of Return | Weighted Average Fair Value |
|---|---|---|---|---|
| 2007 | 0.00% | 24.87% | 4.77% | $17.82 |
| 2006 | 0.00% | 39.03% | 4.57% | $13.93 |
| 2005 | - | - | - | - |

The total value of share based liabilities paid in 2007, 2006 and 2005 were $4,362,967, $1,447,300 and $819,117, respectively. The total value of shares vested in 2007, 2006, and 2005 were $2,842,265, $2,046,141 and $881,165, respectively.

**Restricted Stock Shares**

There were no restricted shares granted in 2007.

In 2006, 5,643 shares of restricted stock were awarded at a grant price of $13.29 per share; this grant was fully vested on December 31, 2006 and the shares were issued in early 2007.

There were no restricted shares granted in 2005.

In 2004, SPR granted 280,082 performance shares, which were reclassified in 2005 as restricted stock. Due to the achievement of certain performance goals established for this grant, the number of shares available under this grant was increased to 297,587. This grant vested on December 31, 2006, and 237,074 shares were issued in early 2007.

In 2003, SPR granted 438,576 shares of restricted stock at a grant price of $6.60 per share. The shares vested over 4 years with one-third becoming available in each of the years ended December 31, 2004, 2005, and 2006. In early 2007, 111,255 shares were issued under this grant.

The total value of share based liabilities paid in 2007, 2006 and 2005 were $5,957,366, $1,500,321 and $1,405,724, respectively. The total value of shares vested in 2007, 2006 and 2005 were $0, $5,750,643 and $1,596,657, respectively.

**Employee Stock Purchase Plan**

Upon the inception of SPR's employee stock purchase plan, SPR was authorized to issue up to an aggregate of 400,162 shares of common stock to all of its employees with minimum service requirements. On June 19, 2000, shareholders approved an additional 700,000 shares for distribution under the plan. According to the terms of the plan, employees can choose twice each year to have up to 15% of their base earnings withheld to purchase SPR's common stock. The purchase price of the stock is the lesser of 90% of the market value on the offering commencement date, or 100% of the market value on the offering exercise date. Employees can withdraw from the plan at any time prior to the exercise date. Under the plan SPR sold 56,835, 55,954 and 53,162 shares to employees in 2007, 2006, and 2005, respectively.

SPR adopted SFAS 123R "Share Based Payment" in 2006, and according to the requirements set forth in that standard, recognized expense in 2007 and 2006 related to the employee stock purchase plan. For purposes of determining the expense for 2007 and 2006, and the 2005 pro forma disclosures, 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 2007, 2006 and 2005, with an option life of six months:

| Year | Average Dividend Yield | Average Expected Volatility | Average Risk-Free Rate of Return | Weighted Average Fair Value |
|---|---|---|---|---|
| 2007 | 0.00% | 20.75% | 4.13% | $3.02 |
| 2006 | 0.00% | 19.73% | 4.95% | $2.62 |
| 2005 | 0.00% | 35.87% | 2.23% | $2.65 |

## NOTE 13. COMMITMENTS AND CONTINGENCIES

### Purchased Power

The Utilities have several contracts for long-term purchase of electric energy. Expiration of these contracts ranges from 2008 to 2039. Estimated future commitments under non-cancelable agreements as of December 31, 2007 were as follows (dollars in thousands):

| | Purchased Power | | |
|---|---|---|---|
| | NPC | SPPC | SPR |
| 2008 | $ 349,322 | $ 152,428 | $ 501,750 |
| 2009 | 286,016 | 123,975 | 409,991 |
| 2010 | 338,323 | 167,257 | 505,580 |
| 2011 | 372,613 | 190,799 | 563,412 |
| 2012 | 394,765 | 203,765 | 598,530 |
| Thereafter | 5,151,777 | 3,488,879 | 8,640,656 |

### 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 2008 to 2018. Estimated future commitments under non-cancelable agreements as of December 31, 2007 were as follows (dollars in thousands):

| | Coal and Gas | | | Transportation | | |
|---|---|---|---|---|---|---|
| | NPC | SPPC | Total | NPC | SPPC | Total |
| 2008 | $ 222,562 | $ 122,143 | $ 344,705 | $ 42,002 | $ 72,772 | $ 114,774 |
| 2009 | 19,595 | 22,703 | 42,298 | 37,545 | 65,110 | 102,655 |
| 2010 | 12,584 | 16,250 | 28,834 | 36,816 | 44,512 | 81,328 |
| 2011 | 6,316 | 16,250 | 22,566 | 34,702 | 44,502 | 79,204 |
| 2012 | - | - | - | 28,429 | 44,407 | 72,836 |
| Thereafter | - | - | - | 156,410 | 295,366 | 451,776 |

### Long-Term Service Agreements

NPC entered into long-term service agreements for the performance of maintenance on generation units located at the Chuck Lenzie Generation Station and Silverhawk Generation Station. SPPC entered into a long-term service agreement for the Tracy Combined Cycle Plant which is estimated to be operational May 2008. Future commitments under these agreements are as follows (dollars in thousands):

| | Long-Term Service Agreements | | | |
|---|---|---|---|---|
| | Silverhawk | Lenzie | Tracy Combined Cycle | Total |
| 2008 | $ 5,886 | $ 11,258 | $ 3,106 | $ 20,250 |
| 2009 | 5,886 | 11,258 | 5,325 | 22,469 |
| 2010 | 5,886 | 11,258 | 5,325 | 22,469 |
| 2011 | 5,886 | 11,258 | 5,325 | 22,469 |
| 2012 | 5,886 | 11,258 | 5,325 | 22,469 |
| Thereafter | 23,545 | 90,062 | 61,770 | 175,377 |

### Capital Projects

NPC has entered into agreements for purchase and construction of Clark peaking units. Completion of this project is estimated for second quarter 2008. Additionally, NPC has entered in to a purchase agreement for a turbine for the Harry Allen Combined Cycle project. Estimated completion is 2010. NPC has entered into environmental contracts for upgrading the Clark Units 5-8. Completion of this project is estimated in 2009. A contract for tenant improvements for the Southern Operations Center at NPC is expected to be completed in 2008.

SPPC has entered into an agreement for construction of the Tracy Combined Cycle Plant. Estimated completion is 2008. Future commitments under these agreements are as follows (dollars in thousands):

| | Capital Projects | | |
|---|---|---|---|
| | NPC | SPPC | Total |
| 2008 | $ 190,565 | $ 6,028 | $ 196,593 |
| 2009 | 72,425 | - | 72,425 |
| 2010 | 2,873 | - | 2,873 |

**Operating Leases**

NPC has an operating lease for its Southern Operations Center with a termination date of October 2027. SPPC has an operating lease for its general offices. 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. In addition, the Utilities entered into master leasing agreements for various equipment.

SPR's, NPC's and SPPC's estimated future minimum cash payments under non-cancelable operating leases as of December 31, 2007, were as follows (dollars in thousands):

| | Operating Leases | | |
|---|---|---|---|
| | NPC | SPPC | Total |
| 2008 | $ 10,391 | $ 12,672 | $ 23,063 |
| 2009 | 9,630 | 11,605 | 21,235 |
| 2010 | 8,947 | 10,682 | 19,629 |
| 2011 | 6,027 | 3,329 | 9,356 |
| 2012 | 4,142 | 1,557 | 5,699 |
| Thereafter | 33,961 | 37,452 | 71,413 |

**Environmental**

**Nevada Power Company**

*Reid Gardner Station*

*Surface and Groundwater Matters*

Reid Gardner Station is a coal generating station consisting of four units. Unit no. 4 is co-owned by the California Department of Water Resources (CDWR) 67.8% and 32.2% by NPC. NPC is the operating agent.

Reid Gardner has a number of raw water and scrubber make-up storage ponds as well as ponds used for process water evaporation and fly ash settling. Process water, which has been used beyond the treatable limits, is routed to onsite ponds for evaporation. Waste management units are present throughout the site and surrounding area. Environmental contaminants identified at Reid Gardner include but are not limited to, elevated concentrations of total dissolved solids, sulfate, chloride, dissolved metals, volatile organic compounds and petroleum hydrocarbons.

In August 1999, the Nevada Department of Environmental Protection (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 ten years. This order also required NPC to submit a Site Characterization Plan to NDEP to ascertain impacts. This plan has been reviewed and approved by NDEP. In collaboration with NDEP, NPC has evaluated remediation requirements. In May 2004, NPC submitted a schedule of remediation actions to NDEP which included proposed dates for corrective action plans and/or suggested additional assessment plans for each specified area. Any future ponds will be double-lined with inter-liner leak detection in accordance with the NDEP Authorization to Discharge Permit issued October 2005.

Pond construction and lining costs to satisfy the NDEP order expended to date is approximately $45 million. Expenditures for 2008 are projected to be approximately $2.8 million, for a total expenditure of approximately $47.8 million.

Over the last two years, the water division of NDEP has been in discussions with NPC regarding what additional surface and groundwater cleanup may be required at the site, beyond the scope of the current pond relining project. The proposed solution was to enter into an Administrative Order on Consent (AOC) and the final form of the proposed AOC was delivered to NPC in December 2007. Until such time, NPC did not know the extent of the obligation or scope of work that would be required to effect site restoration due to the complexities associated with environmental remediation of the target media and the evolving standards of acceptable

remediation standards. As a result, management was unable to reasonably estimate the cost of this comprehensive remediation project prior to concluding the negotiations and receiving the final AOC from the NDEP.

In February 2008, NPC signed the AOC as owner and operator of Unit Nos. 1, 2 and 3 and as co-owner and Operating Agent of Unit No. 4. The AOC has been designed to supersede previous agreements for remedial activities at the site and takes a comprehensive approach to address historical environmental impacts associated with facility operations. Upon receiving the final document in December 2007, management was able to estimate a range of costs to satisfy the requirements of the AOC. As a result NPC has recorded as an asset retirement obligation in accordance with SFAS 143, Accounting for Asset Retirement Obligations as of December 31, 2007 of approximately $19.8 million, which it expects to receive regulatory recovery of, similar to other Asset Retirement Obligations. Other costs are expected to include capital expenditures and remediation costs of approximately $32.3 million and operating and maintenance expense of approximately $1.3 million. However, these estimates may vary significantly once the scope of work is initiated and additional characterization is completed.

*Air Quality Matters*

In June 2006, the Environmental Protection Agency (EPA) issued a Finding and Notice of Violation (NOV) related to monitoring, recordkeeping and emission exceedances at the Reid Gardner facility. In April 2007, NPC lodged a Consent Decree in federal district court with NDEP, EPA and the Department of Justice (DOJ) regarding the NOVs and providing for additional environmental controls and equipment changes, environmental benefit projects, monetary penalties, and/or other measures that will be required to resolve the alleged violations. Terms of the Consent Decree included a $1.1 million fine, which was paid during 2007, funding of projects, of which NPC expects to spend approximately $2 million for the Supplemental Environmental Project with the Clark County School District, and the installation of emission reduction equipment at the facility. The environmental project is aimed at achieving increased energy efficiency and cost savings for the school district. Certain environmental controls and equipment changes needed to assure compliance with existing or modified regulations, and which will satisfy the terms of the consent decree, were previously submitted by NPC to the PUCN in NPC's 2006 IRP filing. These expenditures were approved by the PUCN in late 2006 and include equipment installation on the various units to control startup opacity and particulates and reduce operating opacity and oxides of nitrogen. Capital expenditures are estimated at $84.0 million as approved by the PUCN; however, amounts may change depending on the procurement of material and services.

*Clark Station*

In May 2006, the EPA, by letter from the DOJ, notified NPC that it intended to initiate an enforcement action against NPC seeking unspecified civil penalties, together with injunctive relief, for alleged violations of the Prevention of Significant Deterioration requirements and Title V operating permit requirements of the Clean Air Act at Clark Station. NPC then entered into ongoing dialogue and settlement discussions with the EPA and DOJ regarding the alleged violations and in August 2007, a final Consent Decree between NPC and the EPA was entered with the Court. Terms of the Consent Decree include installation of an advanced NOx reduction burner technology on four existing units with an estimated cost of up to $60 million, which cost was previously submitted by NPC to the PUCN in its Second Amendment to the 2006 IRP filing and was approved in May 2007. Additionally, NPC paid a minimal fine and will make a contribution to Vegas Public Broadcasting Service (PBS) to fund a solar panel array on its new Educational Technology Campus planned in Clark County.

*NEICO*

NEICO, a wholly-owned subsidiary of NPC, owns property in Wellington, Utah, which was the site of a coal washing and load-out facility. The site has a reclamation estimate supported by a bond of approximately $5 million with the Utah Division of Oil and Gas Mining, which management believes is sufficient to cover reclamation costs. Management is continuing to evaluate various options including reclamation and sale.

**Litigation Contingencies**

**Nevada Power Company and Sierra Pacific Power Company**

*Enron Litigation*

*Settlement Agreement*

On February 1, 2006, the Utilities completed the settlement of long-term, ongoing litigation involving Enron's market manipulation during the Western United States energy crisis and Enron's claims with respect to terminated purchase power contracts between Enron Power Marketing Inc. ("Enron") and the Utilities in accordance with the terms of the Settlement Agreement, entered into as of November 15, 2005 among the Utilities, Enron, and other related Enron affiliates (the "Settlement Agreement"). The Settlement Agreement provided for the settlement and release of the on-going litigation, regulatory proceedings, appellate proceedings, proofs of claim and other claims between Enron and the Utilities related to these matters. The Settlement Agreement received approval from the Enron Bankruptcy Court on December 15, 2005. The FERC's approval of the Settlement Agreement was

received on January 25, 2006, which triggered the mutual releases and discharges of all past, existing and future claims between the parties.

On January 26, 2006, upon final approval of the settlement with Enron, the Utilities paid Enron approximately $129 million from available cash resources. On January 27, 2006, the approximate $60 million cash held in escrow, plus interest, and NPC's General and Refunding Series H Bond of approximately $185.7 million and SPPC's General and Refunding Series E Bond of approximately $92.3 million were returned to the Utilities. As part of the settlement, NPC and SPPC were granted general unsecured claims (the "Unsecured Claims") in Class Six of Enron's Plan of Reorganization in the amount of $80.7 million and $45.8 million, respectively. On October 24, 2005, the Utilities purchased a put option from a major international banking institution that, if exercised, obligated that institution to purchase the Unsecured Claims (contingent upon allowance of the Unsecured Claims by the Bankruptcy Court), which ensured that the Utilities' net cash outlay to settle Enron's claim would be no higher than $89.9 million. On February 16, 2006, the Unsecured Claims were sold to a separate third party, resulting in a final net cash outlay which did not materially differ from the anticipated cash outlay.

**Nevada Power Company**

*Peabody Western Coal Company*

NPC owns an 11% interest in the Navajo Generating Station (Navajo Station) which is located in Northern Arizona and is operated by the Salt River Project (Salt River). Other participants in the Navajo Station are Arizona Public Service Company, Los Angeles Department of Water and Power and Tucson Electric Power Company (together with Salt River and NPC, the "Navajo Joint Owners"). NPC also owns a 14% interest in the Mohave Generating Station (Mohave Station) which is located in Laughlin, Nevada and was operated by Southern California Edison (SCE) prior to the time it became non-operational on December 31, 2005.

*Royalty Claim*

On October 15, 2004, Navajo Station's coal supplier, Peabody Western Coal Co. (Peabody WC), filed a complaint against the Navajo Joint Owners in Missouri State Court in St. Louis, alleging, among other things, a declaration that the Navajo Joint Owners are obligated to reimburse Peabody WC for any royalty, tax or other obligations arising out of a lawsuit that the Navajo Nation filed against Salt River, several Peabody Coal Company entities (including Peabody WC and collectively referred to as "Peabody") and SCE in June 1999 in the U.S. District Court for the District of Columbia (DC Lawsuit).

The Navajo Joint Owners were first served in the Missouri lawsuit in January 2005. The operating agent for the Navajo Station, Salt River, is defending the suit on behalf of the Navajo Joint Owners. NPC believes Peabody WC's claims are without merit and intends to contest them. At this time, discovery is ongoing. In October, 2007, the Navajo Joint Owners filed a motion for partial summary judgment against Peabody WC's claims for reimbursement of attorney fees and indemnification of liability arising out of the DC Lawsuit. In January 2008, Peabody filed responses to the Navajo Joint Owner's motion. On February 13, 2008, the Navajo Joint Owners filed a second partial summary judgment motion seeking dismissal of another count raised by Peabody concerning indemnity arising out of the DC Lawsuit. The court has yet to rule on both partial summary judgment motions. The case is set for trial in December, 2008. NPC is unable to predict the outcome of this matter or whether any other liability may arise as a result of the ultimate outcome of the DC Lawsuit.

NPC is not a party to the DC Lawsuit although, as noted above, it is a participant in both the Navajo Station and the Mohave Station. The DC Lawsuit consists of various claims relating to the renegotiations of coal royalty and lease agreements and alleges, among other things, that the defendants obtained a favorable coal royalty rate for the lease agreements under which Peabody mines coal for both Navajo Station and the Mohave Station by improperly influencing the outcome of a federal administrative process pursuant to which the royalty rate was to be adjusted. The DC Lawsuit seeks $600 million in damages, treble damages, and punitive damages of not less than $1 billion, and the ejection of defendants "from all possessory interests and Navajo Tribal lands arising out of the primary coal lease." In July 2001, the court dismissed all claims against Salt River. The action has been stayed since October 5, 2004. In November, 2007, various parties filed motions to dissolve the stay. The US District Court for the District of Columbia is expected to rule on the motions in the first quarter of 2008.

*Retiree Health Care and Reclamation Claims*

In addition to the above action before the Missouri State Court, Peabody further asserted in 1994 that the Navajo Joint Owners are liable under the Coal Supply Agreement (CSA) for Retiree Health Care Costs (RHCC) and Final Reclamation Costs (FRC), which Peabody WC is obligated to pay after the CSA expires and the Kayenta Mine closes. In 1996, Salt River and the Navajo Joint Owners filed a complaint in the Maricopa County (Arizona) Supreme Court seeking determinations that they are not liable for RHCC or FRC or, alternatively, that Peabody WC cannot recover RHCC and FRC until after the CSA ends. The case was dormant for several years, while Peabody WC pursued other RHCC and FRC claims arising out of similar coal contracts. The RHCC matter is in the early stages of litigation. The FRC claim went to arbitration and parties are in the early process of selecting a panel. Settlement discussions, led by Salt River, are continuous and ongoing. NPC is briefed periodically by Salt River as settlement discussions advance. NPC cannot predict the final outcome of the settlement, but has recorded a $17.4 million liability which

management has assessed as the approximate amount to be paid, and a corresponding other regulatory asset for such claims, as management believes that these costs are recoverable through deferred energy.

**Sierra Pacific Power Company**

*Farad Dam*

SPPC owns four hydro generating plants (10.3 MW capacity) located in California that were to be included in the sale of SPPC's water business for $8 million to the Truckee Meadows Water Authority (TMWA) in June 2001. The contract with TMWA requires that SPPC transfer the hydro assets in working condition. However, one of the four hydro generating plants, Farad 2.8 MW, has been out of service since the summer of 1996 due to a collapsed flume. While planning the reconstruction, a flood on the Truckee River in January 1997 destroyed the diversion dam. The current estimate to rebuild the diversion dam, if management decides to proceed, is approximately $20 million.

SPPC filed a claim with the insurers Hartford Steam Boiler Inspection and Insurance Co. and Zurich-American Insurance Company (Insurers) for the flume and dam. In December 2003, SPPC sued the Insurers in the U.S. District Court for the District of Nevada on a coverage dispute relating to potential rebuild costs. In May 2005, Insurers filed a motion for summary judgment on the coverage issue, which has been denied. In October 2005, Insurers filed another partial summary judgment motion with respect to coverage, which the court also denied. On June 16, 2006, Insurers filed new summary judgment motions, which SPPC opposed. The Court denied the motions and asked parties to brief the Court on certain insurance coverage issues involving timing and cost recovery associated with rebuilding the dam. The Court reviewed the briefs and set a trial date for April 2008. Management has not recorded a loss contingency for this matter, as the loss, if any, can not be estimated at this time.

**Other Legal Matters**

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

## NOTE 14. COMMON STOCK AND OTHER PAID-IN CAPITAL

*Rights Agreement*

In December 2005, the Board of Directors of SPR (the Board) voted to amend the Rights Agreement, dated as of February 2001 (as amended and restated, the "Rights Agreement"), between the SPR and Wells Fargo Bank Minnesota, N.A., to accelerate the final expiration date of the rights ("Rights") issued there under to December 2005, and to terminate the Rights Agreement upon the expiration of the Rights. The Board also adopted a policy governing future entry into a shareholder rights agreement or similar agreement (a "shareholder rights plan"). SPR's policy is to seek shareholder approval prior to the adoption of a shareholder rights plan, unless the board, in the exercise of its fiduciary duties and with the concurrence of a majority of its independent members, determines that, under the circumstances existing at the time, it is in the best interest of SPR's shareholders to adopt a shareholder rights plan without first obtaining shareholder approval. If a shareholder rights plan is adopted without prior shareholder approval, the plan must provide that it shall expire, unless ratified by shareholders, within one year of adoption.

*Employee Stock Ownership Plans*

As of December 31, 2007, 10,956,240 shares of common stock were reserved for issuance under the Common Stock Investment Plan (CSIP), Employees' Stock Purchase Plan (ESPP), and Executive Long-Term Incentive Plan (LTIP).

The 2005 LTIP for officers and key employees allows for the issuance of SPR's common shares through December 2013, which can be earned and issued prior to December 2013. This Plan permits the following types of grants, separately or in combination: nonqualified and qualified stock options; stock appreciation rights; restricted stock; performance units; performance shares, bonus stock and cash.

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.

*Non-Employee Director Stock*

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.

The annual retainer for non-employee directors is $70,000, and the minimum amount to be paid in SPR stock is $35,000 per director. During 2007, 2006, and 2005, SPR granted the following total shares and related compensation to directors in SPR stock, respectively: 27,300, 30,733, and 31,631 shares, and $280,000, $154,000, and $176,000.

*Convertible Notes Issuance*

In February 2003, SPR issued and sold $300 million of its 7.25% Convertible Notes due 2010. In August 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. In August 2005, SPR announced an offer to pay a cash premium to induce holders to convert their 7.25% Notes to shares of SPR common stock. The conversion offer was accepted by 100% of the holders. In September 2005, 65,749,096 shares of common stock, plus cash in lieu of fractional shares, were issued to the holders in exchange for the 7.25% Notes.

In September 2005, 65,749,096 shares of common stock, plus cash in lieu of fractional shares and an aggregate of $54 million in cash consideration were paid to the holders in exchange for the Convertible Notes. In accordance with SFAS No. 84, "Induced Conversion of Convertible Debt," the $54 million cash payment was expensed during the third quarter of 2005.

*Stock Exchange Transactions*

In November 2005 SPR issued 17,344,183 shares of common stock, along with cash in lieu of fractional shares in connection with its PIES. Each PIES consisted of a forward stock purchase contract and a senior unsecured note issued by SPR.

In May 2005, SPR exchanged approximately 41% of the PIES for newly issued PIES ("New PIES") and issued, as a component of the New PIES $99,142,000 aggregate principal amount of 7.93% Senior Notes, due 2007. These senior notes replaced the notes associated with the PIES. SPR successfully remarketed these notes in June 2005 at an interest rate of 7.803%.

In August 2005, the remaining $141,076,000 aggregate principal amount of its 7.93% Senior Notes associated with the PIES were remarketed. In August 2005, SPR used a portion of the proceeds from the $225 million 6.75% Senior Notes (see Note 6, Long-Term Debt) to purchase all of the 7.93% Senior Notes.

In November 2005, the purchase contract settlement date for the PIES and New PIES, 3.6101 shares per forward purchase contract were exchanged for a total of 17,344,183 shares of common stock issued to holder of the PIES and New PIES.

*Increased Authorized Shares*

In May 2006, SPR's shareholders approved an amendment to SPR's Restated Articles of Incorporation to increase the number of authorized shares of SPR common stock by 100,000,000 shares for a total amount of 350,000,000 authorized shares.

*Common Stock Offering*

In August 2006, SPR issued 20 million shares of its $1 par value common stock. Net proceeds from the issuance were $280.6 million. In August 2006, SPR contributed capital to NPC of approximately $200 million. NPC used the proceeds to repay indebtedness under its revolving credit facility.

In December 2006, SPR contributed capital to SPPC of approximately $75 million. SPPC used the proceeds to repay indebtedness under its revolving credit facility and general corporate purposes. SPR has invested the remaining proceeds in highly liquid short-term investments pending their use for general corporate purposes.

In December 2007, SPR issued 12 million shares of its $1 par value common stock. Net proceeds from the issuance were $202.8 million. In December 2007, SPR contributed capital to NPC of approximately $65 million, and to SPPC of approximately $65 million. Both Utilities used the proceeds to repay indebtedness under their revolving credit facilities, and for general corporate purposes. Additionally, SPR contributed capital to NPC of approximately $53 million and to SPPC of approximately $20 million for general corporate purposes in January 2008.

As of December 31, 2007 SPR has 350 million shares of common stock authorized and approximately 233.7 million shares of common stock issued and outstanding.

*Dividends*

On July 28, 2007, SPR's Board of Directors declared a quarterly cash dividend of $0.08 per share paid on September 12, 2007, to common shareholders of record on August 24, 2007. The dividend was the first dividend declared by SPR since February 2002.

On November 1, 2007, SPR's Board of Directors declared a quarterly cash dividend of $0.08 per share payable on December 12, 2007, to common shareholders of record on November 19, 2007.

On February 7, 2008, SPR's Board of Directors declared a quarterly cash dividend of $0.08 per share payable on March 12, 2008, to common shareholders of record on February 22, 2008.

## NOTE 15. EARNINGS PER SHARE (EPS) (SPR)

The difference, if any, between basic EPS and diluted EPS is due to potentially dilutive common shares resulting from stock options, the employee stock purchase plan, performance and restricted stock plans and the non-employee director stock plan.

Emerging Issues Task Force, Participating Securities and the Two-Class Method under FASB Statement No. 128, (EITF 03-6) requires companies to use the "two-class" method to calculate basic EPS, and the "if-converted" method to calculate diluted EPS if the result was dilutive. On September 8, 2005 SPR issued approximately 65.7 million shares of common stock in connection with the early conversion of the 7.25% Convertible Notes. The weighted average shares outstanding up to the date of conversion are shown separately for the year ending December 31, 2005.

On November 15, 2005 the conversion of SPR's PIES resulted in the issuance of 17.3 million shares. For the year ended December 31, 2005 these shares are included in the denominator on a weighted average basis. See Note 14, Common Stock and Other Paid-In Capital, for discussion of the PIES transaction.

The following table outlines the calculation for earnings per share (EPS):

| | Year ended December 31, | | |
|---|---|---|---|
| | 2007 | 2006 | 2005 |
| **Basic EPS** | | | |
| **Numerator ($000)** | | | |
| Net income applicable to common stock | $ 197,295 | $ 277,451 | $ 62,198 |
| Net income applicable to convertible notes | - | - | 20,039 |
| Net income used for basic calculation | $ 197,295 | $ 277,451 | $ 82,237 |
| **Denominator** | | | |
| Weighted average number of common shares outstanding | 222,180,440 | 208,531,134 | 140,334,552 |
| Shares from conversion of notes | - | - | 45,213,762 |
| | 222,180,440 | 208,531,134 | 185,548,314 |
| **Per Share Amounts** | | | |
| Net income applicable to common stock | $ 0.89 | $ 1.33 | $ 0.44 |
| Net income applicable to convertible notes | $ - | $ - | $ 0.44 |
| **Diluted EPS** | | | |
| **Numerator ($000)** | | | |
| Net income applicable to common stock | $ 197,295 | $ 277,451 | $ 82,237 |
| **Denominator** [(1)] | | | |
| Weighted average number of shares outstanding before dilution | 222,180,440 | 208,531,134 | 140,334,552 |
| Stock options | 123,124 | 91,119 | 47,255 |
| Executive long term incentive plan - restricted | - | 113,456 | 187,810 |
| Non-Employee Director stock plan | 46,551 | 30,754 | 21,193 |
| Employee stock purchase plan | 878 | 3,345 | 3,925 |
| Performance Shares | 203,031 | 251,088 | 124,007 |
| Convertible Stock | - | - | 45,213,762 |
| | 222,554,024 | 209,020,896 | 185,932,504 |
| **Per Share Amounts** | | | |
| Net income applicable to common stock | $ 0.89 | $ 1.33 | $ 0.44 |

(1) The denominator does not include stock equivalents resulting from the options issued under the Nonqualified stock option plan for the years ended December 31, 2007, 2006, and 2005, due to conversion prices being higher than market prices for all periods. Under the nonqualified stock option plan for the years ended December 31, 2007, 2006, and 2005, 638,250, 932,946, and 917,623 shares, respectively, would be included.

## NOTE 16. QUARTERLY FINANCIAL DATA (UNAUDITED)

The following figures are unaudited and include all adjustments necessary in the opinion of management for a fair presentation of the results of interim periods. Dollars are presented in thousands except per share amounts.

**SIERRA PACIFIC RESOURCES**

| | 2007 Quarter Ended | | | |
|---|---|---|---|---|
| | March | June | September | December |
| Operating Revenues | $ 756,431 | $ 851,894 | $ 1,206,050 | $ 786,585 |
| Operating Income | $ 61,930 | $ 86,431 | $ 213,137 | $ 53,069 |
| Net Income Applicable to Common Stock | $ 15,607 | $ 25,754 | $ 152,222 | $ 3,712 |
| Net Income Applicable to Common Stock per Share - Basic and Diluted | $ 0.07 | $ 0.12 | $ 0.69 | $ 0.02 |

| | 2006 Quarter Ended | | | |
|---|---|---|---|---|
| | March | June | September | December |
| Operating Revenues | $ 707,056 | $ 821,919 | $ 1,081,967 | $ 745,008 |
| Operating Income | $ 59,577 | $ 90,683 | $ 283,793 (1) | $ 54,744 |
| Net Income Applicable to Common Stock | $ 1,242 | $ 27,836 | $ 222,246 | $ 26,127 |
| Net Income Applicable to Common Stock per Share - Basic and Diluted | $ 0.01 | $ 0.14 | $ 1.05 | $ 0.12 |

(1) In the third quarter of 2006, operating income includes the reinstatement of deferred energy costs of approximately $180 million.

**NEVADA POWER COMPANY**

| | 2007 Quarter Ended | | | |
|---|---|---|---|---|
| | March | June | September | December |
| Operating Revenues | $ 418,165 | $ 575,108 | $ 894,226 | $ 469,121 |
| Operating Income | $ 27,968 | $ 61,228 | $ 170,264 | $ 37,844 |
| Net Income (Loss) | $ 4,582 | $ 23,604 | $ 133,094 | $ 4,414 |

| | 2006 Quarter Ended | | | |
|---|---|---|---|---|
| | March | June | September | December |
| Operating Revenues | $ 381,275 | $ 543,869 | $ 776,235 | $ 422,702 |
| Operating Income | $ 25,663 | $ 62,019 | $ 244,920 (2) | $ 18,670 |
| Net Income (Loss) | $ (3,296) | $ 28,456 | $ 211,113 | $ (11,733) |

(2) In the third quarter of 2006, operating income includes the reinstatement of deferred energy costs of approximately $180 million.

**SIERRA PACIFIC POWER COMPANY**

| | 2007 Quarter Ended | | | |
|---|---|---|---|---|
| | March | June | September | December |
| Operating Revenues | $ 337,999 | $ 276,734 | $ 311,818 | $ 317,746 |
| Operating Income | $ 33,911 | $ 22,213 | $ 38,118 | $ 11,715 |
| Net Income | $ 21,968 | $ 10,008 | $ 25,552 | $ 8,139 |
| Earnings (Deficit) Applicable to Common Stock | $ 21,968 | $ 10,008 | $ 25,552 | $ 8,139 |

| | 2006 Quarter Ended | | | |
|---|---|---|---|---|
| | March | June | September | December |
| Operating Revenues | $ 325,497 | $ 277,319 | $ 305,445 | $ 321,969 |
| Operating Income | $ 29,991 | $ 24,803 | $ 36,543 | $ 28,680 |
| Net Income | $ 13,272 | $ 8,999 | $ 20,028 | $ 15,410 |
| Earnings Applicable to Common Stock | $ 12,297 | $ 7,633 | $ 20,028 | $ 15,410 |

## ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

## ITEM 9A. CONTROLS AND PROCEDURES

**(a) Evaluation of Disclosure Controls and Procedures** – Sierra Pacific Resources, Nevada Power Company and Sierra Pacific Power Company's principal executive officers and principal financial officers, based on their evaluation of the registrants' disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) of the Securities Exchange Act of 1934) have concluded that, as of December 31, 2007, the registrants' disclosure controls and procedures are adequate and effective to ensure that material information relating to the registrants' and their consolidated subsidiaries is recorded, processed, summarized and reported within the time period specified by the SEC's rules and forms, particularly during the period for which this annual report has been prepared.

**(b) Reports on Internal Control Over Financial Reporting**

**Management's Report on Internal Control Over Financial Reporting**

*Sierra Pacific Resources*

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

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

Sierra Pacific Resources' management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2007. In making this assessment, Sierra Pacific Resources used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework*. Based on our assessment we believe that, as of December 31, 2007, the Company's internal control over financial reporting is effective based on those criteria.

Sierra Pacific Resources' independent registered public accountants have issued an attestation report on the Company's internal control over financial reporting.

## ITEM 9A(T). CONTROLS AND PROCEDURES

*Nevada Power Company*

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

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

Nevada Power Company's management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2007. In making this assessment, Nevada Power Company used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework*. Based on our assessment we believe that, as of December 31, 2007, the Company's internal control over financial reporting is effective based on those criteria.

*Sierra Pacific Power Company*

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

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

Sierra Pacific Power Company's management assessed the effectiveness of the Company's internal control over financial reporting as of December 31, 2007. In making this assessment, Sierra Pacific Power Company used the criteria set forth by the Committee of

Sponsoring Organizations of the Treadway Commission (COSO) in *Internal Control-Integrated Framework*. Based on our assessment we believe that, as of December 31, 2007, the Company's internal control over financial reporting is effective based on those criteria.

Attestation Report

This annual report does not include an attestation report of the independent registered public accountants regarding internal control over financial reporting of Nevada Power Company and Sierra Pacific Power Company. The management reports of Nevada Power Company and Sierra Pacific Power Company were not subject to attestation by the independent registered public accountants pursuant to temporary rules of the SEC that permit Nevada Power Company and Sierra Pacific Power Company to provide only management's reports in their annual report.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

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

We have audited the internal control over financial reporting of Sierra Pacific Resources and subsidiaries (the "Company") as of December 31, 2007, based on criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying "Management's Annual Reports on Internal Control Over Financial Reporting." Our responsibility is to express an opinion on the Company's internal control over financial reporting based on our audit.

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

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

Because of the inherent limitations of internal control over financial reporting, including the possibility of collusion or improper management override of controls, material misstatements due to error or fraud may not be prevented or detected on a timely basis. Also, projections of any evaluation of the effectiveness of the internal control over financial reporting to future periods are subject to the risk that the controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Sierra Pacific Resources and subsidiaries maintained, in all material respects, effective internal control over financial reporting as of December 31, 2007, based on the criteria established in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements and financial statement schedules as of and for the year ended December 31, 2007 of the Company and our report dated February 27, 2008 expressed an unqualified opinion on those financial statements and financial statement schedules and included an explanatory paragraph regarding the Company's adoption of Statement of Financial Accounting Standards No. 123(R).

DELOITTE & TOUCHE LLP

Reno, Nevada
February 27, 2008

**(c) Changes in Internal Controls**

None.

## ITEM 9B. OTHER INFORMATION

None.

## PART III

### ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this Item is incorporated by reference to the definitive proxy statement for our 2008 Annual Meeting of Stockholders to be filed with the Securities and Exchange Commission within 120 days after the end of our 2007 fiscal year (the "2008 Proxy Statement").

### ITEM 11. EXECUTIVE COMPENSATION

The information required by this Item is incorporated by reference to the 2008 Proxy Statement.

### ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT

The information required by this Item is incorporated by reference to the 2008 Proxy Statement.

### ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

The information required by this Item is incorporated by reference to the 2008 Proxy Statement.

### ITEM 14. PRINCIPAL ACCOUNTING FEES AND SERVICES

The information required by this Item is incorporated by reference to the 2008 Proxy Statement.

## PART IV

## ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

### (a) Financial Statements, Financial Statement Schedules and Exhibits



All other schedules have been omitted because they are not required or are not applicable, or the required information is shown in the financial statements or notes thereto. Columns omitted from schedules have been omitted because the information is not applicable.

3. Exhibits:

Exhibits are listed in the Exhibit Index on pages 173 to 182.

## SIGNATURES

Pursuant to the requirements of Section 13 and 15(d) of the Securities Exchange Act of 1934, Sierra Pacific Resources, Nevada Power Company and Sierra Pacific Power Company have each duly caused this report to be signed on their behalf by the undersigned, thereunto duly authorized. The signatures for each undersigned company shall be deemed to relate only to matters having reference to such company and any subsidiaries thereof.

**SIERRA PACIFIC RESOURCES**
**NEVADA POWER COMPANY**
**SIERRA PACIFIC POWER COMPANY**

By _____

Michael W. Yackira
Chief Executive Officer (Principal Executive Officer)
February 22, 2008

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of Sierra Pacific Resources, Nevada Power Company and Sierra Pacific Power Company and in the capacities indicated on the 22nd day of February, 2008.

| | |
|---|---|
| William D. Rogers<br>Chief Financial Officer (Principal Financial Officer) | E. Kevin Bethel<br>Chief Accounting Officer (Principal Accounting Officer) |
| Mary Lee Coleman<br>Director | Jerry E. Herbst<br>Director |
| Krestine M. Corbin<br>Director | John F. O'Reilly<br>Director |
| Theodore J. Day<br>Director | Clyde T. Turner<br>Director |
| Glenn Christenson<br>Director | Joseph B. Anderson, Jr.<br>Director |
| Philip G. Satre<br>Director | Donald D. Snyder<br>Director |
| Walter M. Higgins<br>Director | Brian J. Kennedy<br>Director |
| Michael W. Yackira<br>Director | |

**SIERRA PACIFIC RESOURCES (HOLDING COMPANY)**
**SCHEDULE 1**
**CONDENSED BALANCE SHEETS**
**(Dollars in Thousands)**

| | December 31, | |
|---|---|---|
| | **2007** | **2006** |
| **ASSETS** | | |
| Investments and other property, net | $3,374,387 | $3,045,872 |
| | | |
| Current Assets: | | |
| Cash and cash equivalents | 68,250 | 25,206 |
| Accounts receivable less allowance for uncollectible accounts: | | |
| 2007 and 2006-$0 | 52,279 | 1,755 |
| Current income taxes receivable | 17,882 | - |
| Dividends receivable from subsidiary | 16,167 | 20,208 |
| Materials, supplies and fuel, at average cost | 13 | 13 |
| Deferred income taxes | 41,130 | 138 |
| Other | 260 | 420 |
| | 195,981 | 47,740 |
| Deferred Charges and Other Assets: | | |
| Goodwill | - | 469 |
| Regulatory asset for pension plans | 3,297 | 2,906 |
| Unamortized debt issuance costs | 8,690 | 10,269 |
| Deferred income tax benefit | 855 | 105,010 |
| Other | (4,010) | 1,611 |
| | 8,832 | 120,265 |
| | | |
| **TOTAL ASSETS** | $3,579,200 | $3,213,877 |
| | | |
| **CAPITALIZATION AND LIABILITIES** | | |
| Capitalization: | | |
| Common shareholders' equity | $2,996,575 | $2,622,297 |
| Long-term debt | 525,173 | 550,545 |
| | 3,521,748 | 3,172,842 |
| Current Liabilities: | | |
| Accounts payable | 31,310 | 8,581 |
| Accrued interest | 11,815 | 12,216 |
| Accrued salaries and benefits | 3,309 | 2,948 |
| Accrued taxes | 265 | 212 |
| | 46,699 | 23,957 |
| Commitments and Contingencies (Note 13) | | |
| | | |
| Deferred Credits and Other Liabilities: | | |
| Accrued retirement benefits | 3,808 | 11,691 |
| Other | 6,945 | 5,387 |
| | 10,753 | 17,078 |
| | | |
| **TOTAL CAPITALIZATION AND LIABILITIES** | $3,579,200 | $3,213,877 |

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

**SIERRA PACIFIC RESOURCES (HOLDING COMPANY)**
**SCHEDULE 1**
**CONDENSED INCOME STATEMENTS**
**(Dollars in Thousands)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2007** | **2006** | **2005** |
| **OPERATING EXPENSES:** | | | |
| Operation: | | | |
| Other | $ 3,599 | $ 5,952 | $ 19,006 |
| Taxes: | | | |
| Income taxes (benefits) | (15,650) | (23,595) | (33,078) |
| Other than income | 194 | 172 | 152 |
| | (11,857) | (17,471) | (13,920) |
| **OPERATING INCOME** | 11,857 | 17,471 | 13,920 |
| **OTHER INCOME (EXPENSE):** | | | |
| Early debt conversion fees | - | - | (54,000) |
| Subsidiary earnings | 231,891 | 324,152 | 185,777 |
| Other income | 1,774 | 4,236 | 1,573 |
| Other expense | (5,283) | (6,595) | (2,627) |
| Income (taxes) / benefits | 1,443 | 1,157 | 18,799 |
| | 229,825 | 322,950 | 149,522 |
| Total Income Before Interest Charges | 241,682 | 340,421 | 163,442 |
| **INTEREST CHARGES:** | | | |
| Long-term debt | 42,481 | 51,431 | 74,323 |
| Other | 1,906 | 11,539 | 6,882 |
| | 44,387 | 62,970 | 81,205 |
| **Net Income Applicable to Common Stock** | $ 197,295 | $ 277,451 | $ 82,237 |
| Amount per share basic and diluted | | | |
| Net Income Applicable to Common Stock | $ 0.89 | $ 1.33 | $ 0.44 |
| Weighted Average Shares of Common Stock Outstanding - basic | 222,180,440 | 208,531,134 | 185,548,314 |
| Weighted Average Shares of Common Stock Outstanding - diluted | 222,554,024 | 209,020,896 | 185,932,504 |

**SIERRA PACIFIC RESOURCES (HOLDING COMPANY)**
**SCHEDULE 1**
**CONDENSED STATEMENTS OF CASH FLOWS**
**(Dollars in Thousands)**

| | Year ended December 31, | | |
|---|---|---|---|
| | **2007** | **2006** | **2005** |
| **CASH FLOWS FROM OPERATING ACTIVITIES:** | | | |
| Net Cash from Operating Activities | $ (20,193) | $ (59,166) | $ (147,993) |
| **CASH FLOWS FROM INVESTING ACTIVITIES:** | | | |
| Investments in subsidiaries and other property - net | (134,383) | (284,490) | (231,182) |
| Dividends received from subsidiaries | 44,523 | 161,793 | 65,819 |
| Net Cash used by Investing Activities | (89,860) | (122,697) | (165,363) |
| **CASH FLOWS FROM FINANCING ACTIVITIES:** | | | |
| Change in restricted cash and investments | - | - | 21,677 |
| Proceeds from issuance of long-term debt | - | - | 220,211 |
| Retirement of long-term debt | (25,373) | (110,710) | (132,949) |
| Sale of Common Stock, net of issuance costs | 213,339 | 281,554 | 235,618 |
| Proceeds from exercise of stock option | 548 | 1,040 | 590 |
| Dividends paid | (35,417) | - | - |
| Net Cash from Financing Activities | 153,097 | 171,884 | 345,147 |
| **Net Increase (Decrease) in Cash and Cash Equivalents** | 43,044 | (9,979) | 31,791 |
| Beginning Balance in Cash and Cash Equivalents | 25,206 | 35,185 | 3,394 |
| Ending Balance in Cash and Cash Equivalents | $ 68,250 | $ 25,206 | $ 35,185 |

**Sierra Pacific Resources**
**Schedule II - Consolidated Valuation and Qualifying Accounts**
**For The Years Ended December 31, 2007, 2006 and 2005**
**(Dollars in Thousands)**

| | Provision for Uncollectible Accounts |
|---|---|
| Balance at January 1, 2005 | $ 36,197 |
| Provision charged to income | 9,550 |
| Amounts written off, less recoveries | (9,519) |
| Balance at December 31, 2005 | $ 36,228 |
| Balance at January 1, 2006 | $ 36,228 |
| Provision charged to income | 13,476 |
| Amounts written off, less recoveries | (10,138) |
| Balance at December 31, 2006 | $ 39,566 |
| Balance at January 1, 2007 | $ 39,566 |
| Provision charged to income | 10,584 |
| Amounts written off, less recoveries | (14,089) |
| Balance at December 31, 2007 | $ 36,061 |

**Nevada Power Company**
**Schedule II - Consolidated Valuation and Qualifying Accounts**
**For The Years Ended December 31, 2007, 2006 and 2005**
**(Dollars in Thousands)**

| | Provision for Uncollectible Accounts |
|---|---|
| Balance at January 1, 2005 | $ 30,901 |
| Provision charged to income | 6,966 |
| Amounts written off, less recoveries | (7,481) |
| Balance at December 31, 2005 | $ 30,386 |
| Balance at January 1, 2006 | $ 30,386 |
| Provision charged to income | 10,795 |
| Amounts written off, less recoveries | (8,347) |
| Balance at December 31, 2006 | $ 32,834 |
| Balance at January 1, 2007 | $ 32,834 |
| Provision charged to income | 9,269 |
| Amounts written off, less recoveries | (11,711) |
| Balance at December 31, 2007 | $ 30,392 |

**Sierra Pacific Power Company**
**Schedule II - Consolidated Valuation and Qualifying Accounts**
**For The Years Ended December 31, 2007, 2006 and 2005**
**(Dollars in Thousands)**

| | Provision for Uncollectible Accounts | |
|---|---|---|
| Balance at January 1, 2004 | $ | 5,296 |
| Provision charged to income | | 2,584 |
| Amounts written off, less recoveries | | (2,038) |
| Balance at December 31, 2004 | $ | 5,842 |
| | | |
| Balance at January 1, 2006 | $ | 5,842 |
| Provision charged to income | | 2,681 |
| Amounts written off, less recoveries | | (1,791) |
| Balance at December 31, 2006 | $ | 6,732 |
| | | |
| Balance at January 1, 2007 | $ | 6,732 |
| Provision charged to income | | 1,315 |
| Amounts written off, less recoveries | | ( 2,378) |
| Balance at December 31, 2007 | $ | 5,669 |

## 2007 FORM 10-K EXHIBIT INDEX

(a) Exhibits Index

Certain of the following exhibits with respect to SPR and its subsidiaries, Nevada Power Company, Sierra Pacific Power Company, Lands of Sierra, Inc., Sierra Pacific Energy Company and Sierra Water Development Company, are filed herewith. Certain other of such exhibits have heretofore been filed with the Commission and are incorporated herein by reference.

(* filed herewith)

**(3) Sierra Pacific Resources**

- Restated and Amended Articles of Incorporation of Sierra Pacific Resources, dated May 24, 2006 (filed as Exhibit 3.1 to Form 10-Q for quarter ended June 30, 2006).

- By-laws of Sierra Pacific Resources as amended through May 3, 2005 (filed as Exhibit 3.1 to Form 8-K dated May 9, 2005).

**Nevada Power Company**

- Restated Articles of Incorporation of Nevada Power Company, dated July 28, 1999 (filed as Exhibit 3(B) to Form 10-K for year ended December 31, 1999).

- Amended and Restated By-Laws of Nevada Power Company dated July 28, 1999 (filed as Exhibit 3(C) to Form 10-K for year ended December 31, 1999).

**Sierra Pacific Power Company**

- Restated Articles of Incorporation of Sierra Pacific Power Company dated October 25, 2006 (filed as Exhibit 3.1 to Form 10-Q for the quarter ended September 30, 2006).

- By-laws of Sierra Pacific Power Company, as amended through November 13, 1996 (filed as Exhibit (3)(A) to Form 10-K for the year ended December 31, 1996).

- Articles of Incorporation of Piñon Pine Corp., dated December 11, 1995 (filed as Exhibit (3)(A) to Form 10-K for the year ended December 31, 1995).

- Articles of Incorporation of Piñon Pine Investment Co., dated December 11, 1995 (filed as Exhibit (3)(B) to Form 10-K for the year ended December 31, 1995).

- Agreement of Limited Liability Company of Piñon Pine Company, L.L.C., dated December 15, 1995, between Piñon Pine Corp., Piñon Pine Investment Co. and GPSF-B INC 1995 (filed as Exhibit (3)(C) to Form 10-K for the year ended December 31, 1995).

- Amended and Restated Limited Liability Company Agreement of SPPC Funding LLC dated as of April 9, 1999, in connection with the issuance of California rate reduction bonds (filed as Exhibit (3)(A) to Form 10-K for the year ended December 31, 1999).

**(4) Sierra Pacific Resources**

- Indenture between Sierra Pacific Resources and The Bank of New York, dated May 1, 2000, for the issuance of debt securities (filed as Exhibit 4.1 to Form 8-K dated May 22, 2000).

- Officers' Certificate dated August 12, 2005, establishing the terms of Sierra Pacific Resources' 6 3/4% Senior Notes due 2017 (filed as Exhibit 4.1 to Form 10-Q for the quarter ended September 30, 2005).

- Form of Sierra Pacific Resources' 6 3/4% Senior Notes due 2017 (filed as Exhibit 4.2 to Form 10-Q for the quarter ended September 30, 2005).

- Officers' Certificate dated June 14, 2005, establishing the terms of Sierra Pacific Resources' 7.803% Senior Notes due 2007 (filed as Exhibit 99.1 to Form 8-K dated June 16, 2005).

- Indenture, dated March 19, 2004, between Sierra Pacific Resources and the Bank of New York, as Trustee, in connection with the issuance of 8 5/8% Senior Notes due 2014 (filed as Exhibit 4.1 to Form 10-Q for the quarter ended March 31, 2004).

- Form of Sierra Pacific Resources' 8 5/8% Senior Notes due 2014 (filed as Exhibit 4.1 to Form 10-Q for the quarter ended March 31, 2004).

**Nevada Power Company**

- General and Refunding Mortgage Indenture, dated May 1, 2001, between Nevada Power Company and The Bank of New York, as Trustee (filed as Exhibit 4.1(a) to Form 10-Q for the quarter ended June 30, 2001).

  - First Supplemental Indenture, dated as of May 1, 2001, establishing Nevada Power Company's 8.25% General and Refunding Mortgage Bonds, Series A, due June 1, 2011 (filed as Exhibit 4.1(b) to Form 10-Q for the quarter ended June 30, 2001).

  - Officer's Certificate establishing the terms of Nevada Power Company's 8.25% General and Refunding Mortgage Bonds, Series A, due June 1, 2011 (filed as Exhibit 4.l(c) to Form 10-Q for the quarter ended June 30, 2001).

  - Form of Nevada Power Company's 8.25% General and Refunding Mortgage Bonds, Series A, due June 1, 2011 (filed as Exhibit 4.1(d) to Form 10-Q for the quarter ended June 30, 2001).

  - Officer's Certificate establishing the terms of Nevada Power Company's 9% General and Refunding Mortgage Notes, Series G, due 2013 (filed as Exhibit 4.1 to Form 10-Q for the quarter ended September 30, 2003).

  - Form of Nevada Power Company's 9% General and Refunding Mortgage Notes, Series G, due 2013 (filed as Exhibit 4.2 to Form 10-Q for the quarter ended September 30, 2003).

  - Officer's Certificate establishing the terms of Nevada Power Company's 6 1/2% General and Refunding Mortgage Notes, Series I, due 2012 (filed as Exhibit 4.1 to Form 10-Q for quarter ended June 30, 2004).

  - Form of Nevada Power Company's 6 1/2% General and Refunding Mortgage Notes, Series I due 2012 (filed as Exhibit 4.2 to Form 10-Q for quarter ended June 30, 2004).

  - Officer's Certificate establishing the terms of Nevada Power Company's 5 7/8% General and Refunding Mortgage Notes, Series L, due 2015 (filed as Exhibit 4(A) to Form 10-K filed for year ended December 31, 2005).

  - Form of Nevada Power Company's 5 7/8% General and Refunding Mortgage Notes, Series L, due 2015 (filed as Exhibit 4(B) to Form 10-K filed for year ended December 31, 2005).

  - Officer's Certificate establishing the terms of Nevada Power Company's 5.95% General and Refunding Mortgage Notes, Series M, due 2016 (filed as Exhibit 4(A) to Form 10-K for the year ended December 31, 2005).

  - Form of Nevada Power Company's 5.95% General and Refunding Mortgage Notes, Series M, due 2016 (filed as Exhibit 4(B) to Form 10-K for the year ended December 31, 2005).

  - Officer's Certificate establishing the terms of Nevada Power Company's 6.650% General and Refunding Mortgage Notes, Series N, due 2036 (filed as Exhibit 4.1 to Form 10-Q for the quarter ended March 31, 2006.

  - Form of Nevada Power Company's 6.650% General and Refunding Mortgage Notes, Series N, due 2036 (filed as Appendix A to Exhibit 4.1 to Form 10-Q for the quarter ended March 31, 2006).

  - Officer's Certificate establishing the terms of Nevada Power Company's 6.50% General and Refunding Mortgage Notes, Series O, due 2018 (filed as Exhibit 4.7 to Form S-4 filed June 7, 2006).

  - Form of Nevada Power Company's 6.50% General and Refunding Mortgage Notes, Series O, due 2018 (filed as Appendix A to Exhibit 4.7 to Form S-4 filed June 7, 2006).

- Officer's Certificate establishing the terms of Nevada Power Company's 6.750% General and Refunding Mortgage Notes, Series R, due 2037 (filed as Exhibit 4.1 to Form 8-K dated June 27, 2007).

- Form of Nevada Power Company's 6.750% General and Refunding Mortgage Notes, Series R, due 2037 (filed as Appendix A to Exhibit 4.1 to Form 8-K dated June 27, 2007).

**Sierra Pacific Power Company**

- General and Refunding Mortgage Indenture, dated as of May 1, 2001, between Sierra Pacific Power Company and The Bank of New York as Trustee (filed as Exhibit 4.2(a) to Form 10-Q for the quarter ended June 30, 2001).

  - First Supplemental Indenture, dated as of May 1, 2001, establishing Sierra Pacific Power Company's 8% General and Refunding Mortgage Bonds, Series A, due June 1, 2008 (filed as Exhibit 4.2(b) to Form 10-Q for the quarter ended June 30, 2001).

  - Second Supplemental Indenture, dated as of October 30, 2006, to subject additional properties of Sierra Pacific Power Company located in the State of California to the lien of the General and Refunding Mortgage Indenture and to correct defects in the original Indenture (filed as Exhibit 4(A) to Form 10-K for the year ended December 31, 2006).

  - Officer's Certificate establishing the terms of Sierra Pacific Power Company's 8% General and Refunding Mortgage Bonds, Series A, due June 1, 2008 (filed as Exhibit 4.2(c) to Form 10-Q for the quarter ended June 30, 2001).

  - Form of Sierra Pacific Power Company's 8% General and Refunding Mortgage Bonds, Series A, due June 1, 2008 (filed as Exhibit 4.2(d) to Form 10-Q for the quarter ended June 30, 2001).

  - Officer's Certificate establishing the terms of Sierra Pacific Power Company's 6 1/4% General and Refunding Mortgage Bonds, Series H, due 2012 (filed as Exhibit 4.4 to Form 10-Q for the quarter ended March 31, 2004).

  - Form of Sierra Pacific Power Company's 6 1/4% General and Refunding Mortgage Bonds, Series H, due 2012 (filed as Exhibit 4.5 to Form 10-Q for the quarter ended March 31, 2004).

  - Officer's Certificate establishing the terms of Sierra Pacific Power Company's General and Refunding Mortgage Notes, Series J, due 2009 (filed as Exhibit 4(E) to Form 10-K for the year ended December 31, 2004).

  - Form of Sierra Pacific Power Company's General and Refunding Mortgage Notes, Series J, due 2009 (filed as Exhibit 4(F) to Form 10-K for the year ended December 31, 2004).

  - Officer's Certificate establishing the terms of Sierra Pacific Power Company's 6% General and Refunding Mortgage Notes, Series M, due 2016 (filed as Exhibit 4.4 to Form 10-Q for the quarter ended March 31, 2006).

  - Form of Sierra Pacific Power Company's 6% General and Refunding Mortgage Notes, Series M, due 2016 (filed as Appendix A to Exhibit 4.4 to Form 10-Q for the quarter ended March 31, 2006).

  - Officer's Certificate establishing the terms of Sierra Pacific Power Company's 6.750% General and Refunding Mortgage Notes, Series P, due 2037 (filed as Exhibit 4.2 to Form 8-K dated June 27, 2007).

  - Form of Sierra Pacific Power Company's 6.750% General and Refunding Mortgage Notes, Series P, due 2037 (filed as Appendix A to Exhibit 4.2 to Form 8-K dated June 27, 2007).

- Indenture dated as of April 9, 1999 between SPPC Funding LLC and Bankers Trust Company of California, N.A., in connection with the issuance of California rate reduction bonds (filed as Exhibit 4(C) to Form 10-K for the year ended December 31, 1999).

  - First Series Supplement dated as of April 9, 1999 to Indenture between SPPC Funding LLC and Bankers Trust Company of California, N.A., in connection with the issuance of California rate reduction bonds (filed as Exhibit 4(D) to Form 10-K for year ended December 31, 1999).

  - Form of SPPC Funding LLC Notes, Series 1999-1, in connection with the issuance of California rate reduction bonds (filed as Exhibit 4(E) to Form 10-K for year ended December 31, 1999).

**(10) Sierra Pacific Resources**

- *(A) Employment letter dated May 21, 2002 for Donald L. Shalmy.
- *(B) Written description of employment arrangement for William D. Rogers..
- *(C) Written description of employment arrangement for Jeffrey L. Ceccarelli.
- *(D) Employment Letter dated May 9, 2007 for Michael W. Yackira.
- Employment Agreement for Walter M. Higgins (filed as Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2003).
- Amendment to Employment Agreement for Walter M. Higgins (filed as Exhibit 10.1 to Form 10-Q for the quarter ended June 30, 2006).
- Paul J. Kaleta Employment Letter dated January 9, 2006 (filed as Exhibit 10(A) to Form 10-K for the year ended December 31, 2005).
- Stephen R. Wood Employment Letter dated June 29, 2004 (filed as Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2004).
- Roberto Denis Employment Letter dated July 11, 2003 (filed as Exhibit 10(B) to Form 10-K for the year ended December 31, 2003).
- Change in Control Agreement by and among Sierra Pacific Resources and the following officers (individually): Jeffrey L. Ceccarelli, Donald L. Shalmy, Michael W. Yackira, Roberto Denis, Stephen R. Wood and Paul J. Kaleta in substantially the same form as the Change in Control Agreement dated May 21, 2001 by and between Sierra Pacific Resources and Dennis D. Schiffel (filed as Exhibit 10(C) to Form 10-K for the year ended December 30, 2001).
- Change in Control Agreement by and among Sierra Pacific Resources and the following officers (individually): Mary O. Simmons and John E. Brown in substantially the same form as the Change in Control Agreement dated May 21, 2001 by and between Sierra Pacific Resources and John E. Brown (filed as Exhibit 10(D) to Form 10-K for the year ended December 30, 2001).
- Sierra Pacific Resources' 2004 Executive Long-Term Incentive Plan (filed as Appendix A to 2004 Proxy Statement).
- Sierra Pacific Resources' 2003 Non-Employee Director Stock Plan, as amended (filed as Exhibit 99.2 to Form S-8 dated October 19, 2007).
- Sierra Pacific Resources' Employee Stock Purchase Plan (filed as Exhibit 99.3 to Form S-8 dated December 13, 1999).

**Nevada Power Company**

- Joint Tenant Contract, dated September 18, 2007, between Nevada Power Company as Tenant, and Beltway Business Park Warehouse No. 2, LLC as Owner, relating to Nevada Power Company's South Operations Center facility (filed as Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2007).
- Lease, dated December 11, 2006, between Nevada Power Company as lessee and Beltway Business Park Warehouse No. 2, LLC as lessor, relating to Nevada Power Company's South Operations Center facility (filed as Exhibit 10(A) to Form 10-K for the year ended December 31, 2006).
- Second Amended and Restated Credit Agreement, dated as of November 4, 2005, among Nevada Power Company, Wachovia Bank, as administrative agent, the Lenders from time to time party thereto and the other parties named therein (filed as Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2005).
- Amendment and Consent, dated April 19, 2006, to the Second Amended and Restated Credit Agreement, dated November 4, 2005, among Nevada Power Company, Wachovia Bank, National Association, as Administrative Agent, the Lenders

from time to time party thereto and the other parties named therein (filed as Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2006).

- Financing Agreement between Clark County, Nevada and Nevada Power Company, dated August 1, 2006 (relating to Clark County, Nevada $39,500,000 Pollution Control Refund Revenue Bonds Series 2006) (filed as Exhibit 10.1 to Form 10-Q for the quarter ended September 30, 2006).

- Financing Agreement between Coconino County, Arizona Pollution Control Corporation and Nevada Power Company, dated August 1, 2006 (relating to Coconino County, Arizona $40,000,000 Pollution Control Corporation Refunding Revenue Bonds Series 2006A) (filed as Exhibit 10.2 to Form 10-Q for the quarter ended September 30, 2006).

- Financing Agreement between Coconino County, Arizona Pollution Control Corporation and Nevada Power Company, dated August 1, 2006 (relating to Coconino County, Arizona Pollution Control Corporation $13,000,000 Pollution Control Refunding Revenue Bonds Series 2006B) (filed as Exhibit 10.3 to Form 10-Q for the quarter ended September 30, 2006).

- Financing Agreement No. 1 between Clark County, Nevada and Nevada Power Company, dated June 1, 2000 (Series 2000A) (filed as Exhibit 10(O) to Form 10-K for the year ended December 31, 2000).

- Financing Agreement No. 2 between Clark County, Nevada and Nevada Power Company, dated June 1, 2000 (Series 2000B) (filed as Exhibit 10(P) to Form 10-K for the year ended December 31, 2000).

- Financing Agreement between Clark County, Nevada and Nevada Power Company, dated November 1, 1997 (relating to Clark County, Nevada $52,285,000 Industrial Development Revenue Bonds, Series 1997A) (filed as Exhibit 10.83 to Form 10-K, File No. 1-4698, for the year ended December 31, 1997).

- Financing Agreement between Clark County, Nevada and Nevada Power Company dated October 1, 1995 (relating to Clark County, Nevada $76,750,000 Industrial Development Revenue Bonds, Series 1995A) (filed as Exhibit 10.75 to Form 10-K, File No. 1-4698, for the year ended December 31, 1995).

- Financing Agreement between Clark County, Nevada and Nevada Power Company dated October 1, 1995 (relating to Clark County, Nevada $85,000,000 Industrial Development Refunding Revenue Bonds, Series 1995B) (filed as Exhibit 10.76 to Form 10-K, File No. 1-4698, for the year ended December 31, 1995).

- Financing Agreement between Clark County, Nevada and Nevada Power Company dated October 1, 1995 (relating to Clark County, Nevada $76,750,000 Industrial Development Revenue Bonds, Series 1995A and $44,000,000 Industrial Development Refunding Revenue Bonds, Series 1995C) (filed as Exhibit 10.77 to Form 10-K, File No. 1-1698, for the year ended December 31, 1995).

- Financing Agreement between Clark County, Nevada and Nevada Power Company dated October 1, 1995 (relating to Clark County, Nevada $20,300,000 Pollution Control Refunding Revenue Bonds, Series 1995D) (filed as Exhibit 10.78 to Form 10-K, File No. 1-4698, for the year ended December 31, 1995).

- Financing Agreement between Clark County, Nevada and Nevada Power Company dated October 1, 1992 (Relating to Industrial Development Refunding Revenue Bonds, Series 1992C) (filed as Exhibit 10.67 to Form 10-K, File No. 1-4698, for the year ended December 31, 1992).

- Financing Agreement between Clark County, Nevada and Nevada Power Company dated June 1, 1992 (Relating to Clark County, Nevada $105,000,000 Industrial Development Revenue Bonds, Series 1992A) (filed as Exhibit 10.65 to Form 10-K, File No. 1-4698, for the year ended December 31, 1992).

- Collective Bargaining Agreement dated as of February 1, 2005, effective through February 1, 2008, between Nevada Power Company and the International Brotherhood of Electrical Workers Local Union No. 396 (filed as Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2005).

- Engineering, Procurement and Construction Agreement dated October 13, 2004 between Nevada Power Company and Fluor Enterprises, Inc. and Exhibit A thereto (filed as Exhibit 10.3 and Exhibit 10.4 to Form 10-Q for the quarter ended September 30, 2004).

- Contract for Sale of Electrical Energy between the State of Nevada and Nevada Power Company, dated July 8, 1987 (filed as Exhibit 10.39 to Form 10-K, File No. 1-4698, for the year ended December 31, 1987).

- Participation Agreement Reid Gardner Unit No. 4 dated July 11, 1979 between Nevada Power Company and California Department of Water Resources (filed as Exhibit 5.34 to Form S-7, File No. 2-65097).

- Amended Mohave Project Coal Slurry Pipeline Agreement dated May 26, 1976 between Peabody Coal Company and Black Mesa Pipeline, Inc. (Exhibit B to Exhibit 10.18) (filed as Exhibit 5.36 to Form S-7, File No. 2-56356).

- Amended Mohave Project Coal Supply Agreement dated May 26, 1976 between Nevada Power Company and Southern California Edison Company, Department of Water and Power of the City of Los Angeles, Salt River Project Agricultural Improvement and Power District and the Peabody Coal Company (filed as Exhibit 5.35 to Porto S-7, File No. 2-56356).

- Navajo Project Co-Tenancy Agreement dated March 23, 1976 between Nevada Power Company, Arizona Public Service Company, Department of Water and Power of the City of Los Angeles, Salt River Project Agricultural Improvement and Power District, Tucson Gas & Electric Company and the United States of America (filed as Exhibit 5.31 to Form 8-K, File No. 1-4696, April 1974).

- Mohave Operating Agreement dated July 6, 1970 between Nevada Power Company, Salt River Project Agricultural Improvement and Power District, Southern California Edison Company and Department of Water and Power of the City of Los Angeles (filed as Exhibit 13.26F to Form S-1, File No. 2-38314).

- Navajo Project Coal Supply Agreement dated June 1, 1970 between Nevada Power Company, the United States of America, Arizona Public Service Company, Department of Water and Power of the City of Los Angeles, Salt River Project Agricultural District Tucson Gas & Electric Company and the Peabody Coal Company (filed as Exhibit 13.27B to Form S-1, File No. 2-38314).

- Eldorado System Conveyance and Co-Tenancy Agreement dated December 20, 1967 between Nevada Power Company and Salt River Project Agricultural Improvement and Power District and Southern California Edison Company (filed as Exhibit 13.30 to Form S-9, File No. 2-28348).

- Mohave Project Plant Site Conveyance and Co-Tenancy Agreement dated May 29, 1967 between Nevada Power Company and Salt River Project Agricultural Improvement and Power District and Southern California Edison Company (filed as Exhibit 13.27 to Form S-9, File No. 2-28348).

- Settlement Agreement dated December 19, 2003, between Nevada Power Company, Pinnacle West Energy Corporation and Southern Nevada Water Authority (filed as Exhibit 10(G) to Form 10-K for the year ended December 31, 2003).

- Sublease Agreement between Powveg Leasing Corp., as Lessor and Nevada Power Company as lessee, dated January 1, 1984 for lease of administrative headquarters (the primary term of the sublease ends in 2014 and the lessee has the option to extend the term up to 25 additional years) (filed as Exhibit 10.31 to Form 10-K, File No. 1-4698, for the year ended December 31, 1983).

**Sierra Pacific Power Company**

- Financing Agreement dated April 1, 2007 between Washoe County and Sierra Pacific Power Company (relating to Washoe County, Nevada $40,000,000 Water Facilities Control Refunding Revenue Bonds (Sierra Pacific Power Company Project) Series 2007A) (filed as Exhibit 10.1 to Form 10-Q for the quarter ended March 31, 2007).

- Financing Agreement dated April 1, 2007 between Washoe County and Sierra Pacific Power Company (relating to Washoe County, Nevada $40,000,000 Water Facilities Control Refunding Revenue Bonds (Sierra Pacific Power Company Project) Series 2007B) (filed as Exhibit 10.2 to Form 10-Q for the quarter ended March 31, 2007).

- Agreement, amended as of March 5, 2007, between Sierra Pacific Power Company and Local Union 1245 of the International Brotherhood of Electrical Workers (filed as Exhibit 10.3 to Form 10-Q for the quarter ended March 31, 2007)

- Amended and Restated Credit Agreement, dated as of November 4, 2005 among Sierra Pacific Power Company, Wachovia Bank, National Association, as administrative agent, the Lenders from time to time party thereto and the other parties named therein (filed as Exhibit 10.2 to Form 10-Q for the quarter ended September 30, 2005).

- Amendment and Consent, dated April 19, 2006, to the Amended and Restated Credit Agreement, dated November 4, 2005, among Sierra Pacific Power Company, Wachovia Bank, National Association, as Administrative Agent, the Lenders from time to time party thereto and the other parties named therein (filed as Exhibit 10.2 to Form 10-Q for the quarter ended March 31, 2006).

- Financing Agreement dated November 1, 2006 between Humboldt County, Nevada and Sierra Pacific Power Company dated November 1, 2006 (relating to Humboldt County, Nevada $49,750,000 Pollution Control Refunding Revenue Bonds (Sierra Pacific Power Company Project) Series 2006) (filed as Exhibit 10(B) to Form 10-K for the year ended December 31, 2006).

- Financing Agreement dated November 1, 2006 between Washoe County, Nevada and Sierra Pacific Power Company dated November 1, 2006 (relating to Washoe County, Nevada $58,750,000 Gas Facilities Control Refunding Revenue Bonds (Sierra Pacific Power Company Project) Series 2006A) (filed as Exhibit 10(C) to Form 10-K for the year ended December 31, 2006).

- Financing Agreement dated November 1, 2006 between Washoe County, Nevada and Sierra Pacific Power Company dated November 1, 2006 (relating to Washoe County, Nevada $75,000,000 Water Facilities Control Refunding Revenue Bonds (Sierra Pacific Power Company Project) Series 2006B) (filed as Exhibit 10(D) to Form 10-K for the year ended December 31, 2006).

- Financing Agreement dated November 1, 2006 between Washoe County, Nevada and Sierra Pacific Power Company dated November 1, 2006 (relating to Washoe County, Nevada $84,800,000 Gas and Water Facilities Control Refunding Revenue Bonds (Sierra Pacific Power Company Project) Series 2006C) (filed as Exhibit 10(E) to Form 10-K for the year ended December 31, 2006).

- Financing Agreement dated as of March 1, 2001 between Sierra Pacific Power Company and Washoe County, Nevada relating to the Washoe County, Nevada Water Facilities Refunding Revenue Bonds (Sierra Pacific Power Company Project) Series 2001 (filed as Exhibit 10(O) to Form 10-K for the year ended December 31, 2001).

- Transition Property Purchase and Sale Agreement dated as of April 9, 1999 between Sierra Pacific Power Company and SPPC Funding LLC in connection with the issuance of California rate reduction bonds (filed as Exhibit 10(B) to Form 10-K for the year ended December 31, 1999).

- Transition Property Servicing Agreement dated as of April 9, 1999 between Sierra Pacific Power Company and SPPC Funding LLC in connection with the issuance of California rate reduction bonds (filed as Exhibit 10(C) to Form 10-K for the year ended December 31, 1999).

- Administrative Services Agreement dated as of April 9, 1999 between Sierra Pacific Power Company and SPPC Funding LLC in connection with the issuance of California rate reduction bonds (filed as Exhibit 10(D) to Form 10-K for the year ended December 31, 1999).

- Collective Bargaining Agreement dated January 1, 2003, effective through December 31, 2005 between Sierra Pacific Power Company and the International Brotherhood of Electrical Workers Local No. 1245 (filed as Exhibit 10(J) to Form 10-K for the year ended December 31, 2003).

- Settlement Agreement and Mutual Release dated May 8, 1992 between Sierra Pacific Power Company and Coastal States Energy Company (filed as Exhibit (10)(D) to Form 10-K for the year ended December 31, 1992; confidential portions omitted and filed separately with the Securities and Exchange Commission).

- Coal Supply Agreement dated January 1, 2002 between Sierra Pacific Power Company and Arch Coal Sales Company, Inc. (5 year term ending on December 31, 2006) (filed as Exhibit 10(R) to Form 10-K for the year ended December 31, 2001).

- Coal Sales Agreement dated May 16, 1978 between Sierra Pacific Power Company and Coastal States Energy Company (confidential portions omitted and filed separately with the Securities and Exchange Commission) (filed as Exhibit 5-GG to Registration No. 2-62476).

- Amendment No. 1 dated November 8, 1983 to Coal Sales Agreement dated May 16, 1978 between Sierra Pacific Power Company and Coastal States Energy Company (filed as Exhibit(10)(B) to Form 10-K for the year ended December 31, 1991).

- Amendment No. 2 dated February 25, 1987 to Coal Sales Agreement dated May 16, 1978 between Sierra Pacific Power Company and Coastal Stores Energy Company (filed as Exhibit (10)(A) to Form 10-K for the year ended December 31, 1993).

- Amendment No. 3 dated May 8, 1992 to Coal Sales Agreement dated May 16, 1978 between Sierra Pacific Power Company and Coastal States Energy Company (filed as Exhibit (10)(B) to Form 10-K for the year ended December 31, 1992; confidential portions omitted and filed separately with the Securities and Exchange Commission).

- Lease dated January 30, 1986 between Sierra Pacific Power Company and Silliman Associates Limited Partnership relating to the Company's corporate headquarters building (filed as Exhibit (10)(I) to Form 10-K for the year ended December 31, 1992).

- Letter of Amendment dated May 18, 1987 to Lease dated January 30, 1986 between Sierra Pacific Power Company and Silliman Associates Limited Partnership relating to the company's corporate headquarters building (filed as Exhibit (10)(K) to Form 10-K for the year ended December 31, 1993).

**Sierra Pacific Communications**

- Unit Redemption, Release, and Sale Agreement entered into by and among Touch America, Inc., Sierra Pacific Communications, and Sierra Touch America LLC, dated as of September 9, 2002 (filed as Exhibit 10.4 to Form 10-Q for the quarter ended September 30, 2002).

- Amended and Restated Conduit Sale Agreement dated September 11, 2002, made by and between Sierra Pacific Communications and Quest Communications Corporation (filed as Exhibit 10.5 to Form 10-Q for the quarter ended September 30, 2002).

**(11) Nevada Power Company and Sierra Pacific Power Company**

- Nevada Power Company and Sierra Pacific Power Company are wholly owned subsidiaries and, in accordance with Paragraph 6 of SFAS No. 128 (Earnings Per Share), earnings per share data have been omitted.

**(12) Sierra Pacific Resources**

- *(A) Statement regarding computation of Ratios of Earnings to Fixed Charges.

**Nevada Power Company**

- *(B) Statement regarding computation of Ratios of Earnings to Fixed Charges.

**Sierra Pacific Power Company**

- *(C) Statement regarding computation of Ratios of Earnings to Fixed Charges.

**(21) Sierra Pacific Resources**

- Nevada Power Company, a Nevada Corporation.
  Sierra Pacific Power Company, a Nevada Corporation.
  Great Basin Energy Company, a Nevada Corporation.
  Lands of Sierra Inc., a Nevada Corporation.
  Sierra Energy Company dba e-three, a Nevada Corporation.
  Sierra Gas Holdings Company, a Nevada Corporation.
  Sierra Pacific Energy Company, a Nevada Corporation.
  Sierra Water Development Company, a Nevada Corporation.
  Tuscarora Gas Pipeline Company, a Nevada Corporation.
  Tuscarora Gas Operating Company, a Nevada Corporation.

**Nevada Power Company**

- Nevada Electric Investment Company, a Nevada Corporation.
  Commonsite, Inc., a Nevada Corporation.

**Sierra Pacific Power Company**

- Piñon Pine Company, a Nevada Corporation.
  Piñon Pine Investment Company, a Nevada Corporation.
  Piñon Pine Investment Co. LLC, a Nevada Limited Liability Company.
  GPSF-B, a Delaware Corporation.
  SPPC Funding LLC, a Delaware Limited Liability Company.

**(23) Sierra Pacific Resources, Nevada Power Company and Sierra Pacific Power Company**

- *(A) Consent of Independent Registered Public Accounting Firm in connection with Sierra Pacific Resources' Registration Statements No. 333-145686 on Form S-3D, Registration Statements No. 333-92651 and No. 333-146822 on Form S-8, and Registration Statement No. 333-146100 on Form S-3ASR.

- *(B) Consent of Independent Registered Public Accounting Firm in connection with Nevada Power Company's Registration Statement No. 333-146100-02 on Form S-3ASR.

- *(C) Consent of Independent Registered Public Accounting Firm in connection with Sierra Pacific Power Company's Registration Statement No. 333-146100-01 on Form S-3ASR.

**(31) Sierra Pacific Resources, Nevada Power Company and Sierra Pacific Power Company**

- *(31.1) Annual Certification of Chief Executive Officer of Sierra Pacific Resources Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

- *(31.2) Annual Certification of Chief Executive Officer of Nevada Power Company Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

- *(31.3) Annual Certification of Chief Executive Officer of Sierra Pacific Power Company Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

- *(31.4) Annual Certification of Chief Financial Officer of Sierra Pacific Resources Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

- *(31.5) Annual Certification of Chief Financial Officer of Nevada Power Company Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

- *(31.6) Annual Certification of Chief Financial Officer of Sierra Pacific Power Company Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

**(32) Sierra Pacific Resources, Nevada Power Company and Sierra Pacific Power Company**

- *(32.1) Certification of Chief Executive Officer of Sierra Pacific Resources Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

- *(32.2) Certification of Chief Executive Officer of Nevada Power Company Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

- *(32.3) Certification of Chief Executive Officer of Sierra Pacific Power Company Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

- *(32.4) Certification of Chief Financial Officer of Sierra Pacific Resources Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

- *(32.5) Certification of Chief Financial Officer of Nevada Power Company Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

- *(32.6) Certification of Chief Financial Officer of Sierra Pacific Power Company Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

**EXHIBIT 12 (A)**

## SIERRA PACIFIC RESOURCES
## RATIOS OF EARNINGS TO FIXED CHARGES
**(Dollars in Thousands)**

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2007 | 2006 | 2005 | 2004 | 2003 |
| EARNINGS AS DEFINED: | | | | | |
| Income (Loss) From Continuing Operations | | | | | |
| After Interest Charges | $ 197,295 | $ 279,792 | $ 86,137 | $ 30,842 | $ (117,286) |
| Income Taxes | 87,555 | 145,605 | 43,118 | 18,050 | (51,275) |
| Income (Loss) From Continuing Operations before Income Taxes | 284,850 | 425,397 | 129,255 | 48,892 | (168,561) |
| Fixed Charges | 310,876 | 336,024 | 319,654 | 324,969 | 384,565 |
| Capitalized Interest (allowance for borrowed funds used during construction) | (25,967) | (17,119) | (24,691) | (8,587) | (5,976) |
| Preferred Stock Dividend Requirement | - | (3,602) | (6,000) | (6,000) | (6,000) |
| Total | $ 569,759 | $ 740,700 | $ 418,218 | $ 359,274 | $ 204,028 |
| FIXED CHARGES AS DEFINED: | | | | | |
| Interest Expensed and Capitalized [(1)] | $ 310,876 | $ 332,422 | $ 313,654 | $ 318,969 | $ 378,565 |
| Preferred Stock Dividend Requirement | - | 3,602 | 6,000 | 6,000 | 6,000 |
| Total | 310,876 | 336,024 | 319,654 | $ 324,969 | $ 384,565 |
| RATIO OF EARNINGS TO FIXED CHARGES | 1.83 | 2.20 | 1.31 | 1.11 | |
| DEFICIENCY | $ - | $ - | $ - | $ - | $ 180,537 |

(1) Includes amortization of premiums, discounts, and capitalized debt expense and interest component of rent expense.

For the purpose of calculating the ratios of earnings to fixed charges, “Fixed charges” represent the aggregate of interest charges on short-term and long-term debt (whether expensed or capitalized), the portion of rental expense deemed to be attributable to interest, and the pre-tax preferred stock dividend requirement of SPPC. “Earnings” represents pre-tax income (or Loss) from continuing operations before pre-tax preferred stock dividend requirement of SPPC and fixed charges (excluding capitalized interest).

**EXHIBIT 12 (B)**

## NEVADA POWER COMPANY
## RATIOS OF EARNINGS TO FIXED CHARGES
**(Dollars in Thousands)**

| | Year Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2007 | 2006 | 2005 | 2004 | 2003 |
| EARNINGS AS DEFINED: | | | | | |
| Income (Loss) From Continuing Operations After Interest Charges | $ 165,694 | $ 224,540 | $ 132,734 | $ 104,312 | $ 19,277 |
| Income Taxes | 78,352 | 117,510 | 63,995 | 56,572 | (614) |
| Income (Loss) From Continuing Operations before Income Taxes | 244,046 | 342,050 | 196,729 | 160,884 | 18,663 |
| Fixed Charges | 190,836 | 190,333 | 159,776 | 145,055 | 195,342 |
| Capitalized Interest (allowance for borrowed funds used during construction) | (13,196) | (11,614) | (23,187) | (5,738) | (2,700) |
| Total | $ 421,686 | $ 520,769 | $ 333,318 | $ 300,201 | $ 211,305 |
| FIXED CHARGES AS DEFINED: | | | | | |
| Interest Expensed and Capitalized [1] | $ 190,836 | $ 190,333 | $ 159,776 | $ 145,055 | $ 195,342 |
| Total | $ 190,836 | $ 190,333 | $ 159,776 | $ 145,055 | $ 195,342 |
| RATIO OF EARNINGS TO FIXED CHARGES | 2.21 | 2.74 | 2.09 | 2.07 | 1.08 |

(1) Includes amortization of premiums, discounts, and capitalized debt expense and interest component of rent expense.

For the purpose of calculating the ratios of earnings to fixed charges, “Fixed charges” represent the aggregate of interest charges on short-term and long-term debt (whether expensed or capitalized) and the portion of rental expense deemed attributable to interest. “Earnings” represents pre-tax income (or loss) from continuing operations before fixed charges (excluding capitalized interest).

**EXHIBIT 12 (C)**

## SIERRA PACIFIC POWER COMPANY
## RATIOS OF EARNINGS TO FIXED CHARGES
**(Dollars in Thousands)**

| | Year ended December 31, | | | | |
|---|---|---|---|---|---|
| | 2007 | 2006 | 2005 | 2004 | 2003 |
| EARNINGS AS DEFINED: | | | | | |
| Income (Loss) From Continuing Operations | | | | | |
| After Interest Charges | $ 65,667 | $ 57,709 | $ 52,074 | $ 18,577 | $ (23,275) |
| Income Taxes | 26,009 | 27,829 | 28,379 | 325 | (12,237) |
| Income (Loss) From Continuing Operations before Income Taxes | 91,676 | 85,538 | 80,453 | 18,902 | (35,512) |
| Fixed Charges | 75,655 | 79,093 | 72,652 | 67,685 | 101,514 |
| Capitalized Interest (allowance for borrowed funds used during construction) | (12,771) | (5,505) | (1,504) | (2,849) | (3,276) |
| Total | $ 154,560 | $ 159,126 | $ 151,601 | $ 83,738 | $ 62,726 |
| FIXED CHARGES AS DEFINED: | $ 75,655 | $ 79,093 | $ 72,652 | $ 67,685 | $ 101,514 |
| Interest Expensed and Capitalized [1] | - | - | - | - | - |
| Total | 75,655 | 79,093 | 72,652 | $ 67,685 | $ 101,514 |
| RATIO OF EARNINGS TO FIXED CHARGES | 2.04 | 2.01 | 2.09 | 1.24 | |
| DEFICIENCY | $ - | $ - | $ - | $ - | $ 38,788 |

(1) Includes amortization of premiums, discounts, and capitalized debt expense and interest component of rent expense.

For the purpose of calculating the ratios of earnings to fixed charges, “Fixed charges” represent the aggregate of interest charges on short-term and long-term debt (whether expensed or capitalized) and the portion of rental expense deemed attributable to interest. “Earnings” represents pre-tax income (or loss) from continuing operations before pre-tax preferred stock dividend requirement and fixed charges (excluding capitalized interest).

**Shareholder Relations**

For specific company related information or cost basis information contact our Shareholder Relations Department:

Sierra Pacific Resources
Shareholder Relations
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

Website:
www.sierrapacificresources.com

**Lost or Stolen Certificates**

If your stock certificates have been lost, stolen, or destroyed, please notify our Stock Transfer Agent, Wells Fargo Shareowner Services.

**Account Consolidation**

You may consolidate your accounts by contacting our Stock Transfer Agent, Wells Fargo Shareowner Services. 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 on Monday, April 28, 2008, at 10:00 a.m. at the Las Vegas Hilton, 3000 Paradise Road, Las Vegas, Nevada.

**2007 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**

Sierra Pacific Resources' 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 as reported by the New York Stock Exchange net composite price history for 2007 and 2006 are as follows:

| | Dividends Paid Per Share | High | Low |
|---|---|---|---|
| 2007 | | | |
| First Quarter | $0.00 | $18.26 | $16.38 |
| Second Quarter | 0.00 | 19.60 | 16.87 |
| Third Quarter | 0.08 | 18.15 | 14.06 |
| Fourth Quarter | 0.08 | 17.76 | 14.89 |
| 2006 | | | |
| First Quarter | $0.00 | $14.60 | $12.68 |
| Second Quarter | 0.00 | 14.35 | 12.68 |
| Third Quarter | 0.00 | 14.91 | 13.30 |
| Fourth Quarter | 0.00 | 17.50 | 14.29 |

Sierra Pacific™
RESOURCES

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