# CALPINE CORP

## FORM 8-K
(Current report filing)

Filed 09/10/01 for the Period Ending 12/31/00

| | |
|---|---|
| Address | 717 TEXAS AVENUE<br>SUITE 1000<br>HOUSTON, TX 77002 |
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| CIK | 0000916457 |
| Symbol | CPN |
| SIC Code | 4911 - Electric Services |
| Industry | Electric Utilities |
| Sector | Utilities |
| Fiscal Year | 12/31 |

# CALPINE CORP

## FORM 8-K
(Unscheduled Material Events)

Filed 9/10/2001 For Period Ending 12/31/2000

| | |
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| Address | 50 WEST SAN FERNANDO ST |
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| Sector | Utilities |
| Fiscal Year | 12/31 |

# UNITED STATES
# SECURITIES AND EXCHANGE COMMISSION
**Washington, D.C. 20549**

# FORM 8-K

# CURRENT REPORT

**Pursuant to Section 13 or 15(d) of**
**the Securities Exchange Act of 1934**

**Date of Report (Date of earliest event reported): December 31, 2000**

# CALPINE CORPORATION
**(A Delaware Corporation)**

| | |
|---|---|
| **001-12079** | **77-0212977** |
| **(Commission File Number)** | **(I.R.S. Employer Identification No)** |

**50 West San Fernando Street**
**San Jose, California 95113**
**Telephone: (408) 995-5115**

**Item 5.** ***Other Events***

On April 19, 2001, Calpine Corporation (the "Company") completed its merger with Encal Energy Ltd. ("Encal"), a Calgary, Alberta-based natural gas and petroleum exploration and development company. Encal shareholders received, in exchange for each share of Encal common stock, 0.1493 shares of Calpine common equivalent shares (called "exchangeable shares") of the Company's subsidiary, Calpine Canada Holdings Ltd. A total of 16,603,633 exchangeable shares were issued to Encal shareholders in exchange for all of the outstanding shares of Encal common stock. Each exchangeable share is exchangeable for one share of Calpine common stock. The transaction was accounted for as a pooling-of-interests.

Included herein are the consolidated financial statements, which have been restated for all periods presented as if Encal and Calpine had always been combined as required by generally accepted accounting principles.

These consolidated financial statements become the Company's historical consolidated financial statements since financial statements covering the date of consummation of the business combination have been issued. Included herein as Exhibit I is Calpine's business section, which describes the Company's business after giving effect to the merger with Encal. Included herein as Exhibit II is a description of Calpine Corporation's properties, including those resulting from the merger with Encal. Included herein as Exhibit III is the selected financial data, which gives retroactive effect to the merger with Encal. Included herein as Exhibit IV is Management's Discussion and Analysis of Financial Condition and Results of Operations, which relates to the consolidated financial statements. Included herein as Exhibit V is the Quantitative and Qualitative Disclosure about Market Risk, which also gives retroactive effect to the merger with Encal. Included herein as Exhibit VI are the consolidated financial statements of Calpine Corporation as of December 31, 2000 and 1999 and for each of the three years in the period ended December 31, 2000. These consolidated financial statements give retroactive effect to the merger with Encal. Supplementary schedules are also included in this exhibit.

This filing should be read in conjunction with Calpine's Quarterly Reports on Form 10-Q for the quarters ended March 31, 2001 and June 30, 2001, and Calpine's Current Reports on Form 8-K dated February 6, 2001, April 9, 2001, April 19, 2001, April 26, 2001, June 26, 2001, July 6, 2001, July 12, 2001, July 16, 2001, July 26, 2001 and September 5, 2001.

Also included herein as Exhibit VII is information on the Company's operating segments for the three and six months ended June 30, 2001.

**Item 7.** ***Financial Statements and Exhibits***

(a) Not applicable.

(b) Not applicable.

(c) Exhibits.

| | |
|---|---|
| I. | Item 1. Business |
| II. | Item 2. Properties |
| III. | Item 6. Selected Financial Data |
| IV. | Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations |
| V. | Item 7a. Quantitative and Qualitative Disclosure about Market Risk |
| VI. | Item 8. Financial Statements and Supplementary Data |
| VII. | Operating Segments for the Three and Six Months Ended June 30, 2001 |
| VIII. | Exhibits to Form 8-K |



**SIGNATURES**

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned hereunto duly authorized.

**CALPINE CORPORATION**

By: /s/ CHARLES B. CLARK, JR.

Charles B. Clark, Jr.
*Senior Vice President and Controller*
*Chief Accounting Officer*

September 7, 2001



**Exhibit I.**

**Item 1.** ***Business***

*Except for historical financial information contained herein, the matters discussed in this annual report may be considered "forward-looking" statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, including statements regarding the intent, belief or current expectations of Calpine Corporation ("the Company") and its management. Prospective investors are cautioned that any such forward-looking statements are not guarantees of future performance and involve a number of risks and uncertainties that could materially affect actual results such as, but not limited to, (i) changes in government regulations, including pending changes in California, and anticipated deregulation of the electric energy industry, (ii) commercial operations of new plants that may be delayed or prevented because of various development and construction risks, such as a failure to obtain financing and the necessary permits to operate or the failure of third-party contractors to perform their contractual obligations, (iii) cost estimates are preliminary and actual costs may be higher than estimated, (iv) the assurance that the Company will develop additional plants, (v) a competitor's development of a lower-cost generating gas-fired power plant, (vi) the risks associated with marketing and selling power from power plants in the newly competitive energy market, (vii) the risks associated with marketing and selling combustion turbine parts and*

*components in the competitive combustion turbine parts market, (viii) the risks associated with engineering, designing and manufacturing combustion turbine parts and components, (ix) delivery and performance risks associated with combustion turbine parts and components attributable to production, quality control, suppliers and transportation, (x) the successful exploitation of an oil or gas resource that ultimately depends upon the geology of the resource, the total amount and cost to develop recoverable reserves, and operational factors relating to the extraction of natural gas, or (xi) those risks and uncertainties identified in Management's Discussion and Analysis — Risk Factors included with the Consolidated Financial Statements in this report and incorporated into this Item 1 — Business section. Prospective investors are also cautioned that the California energy market remains uncertain. The Company's management is working closely with a number of parties to resolve the current uncertainty. This is an ongoing process and, therefore, the outcome cannot be predicted. It is possible that any such outcome will include changes in government regulations, business and contractual relationships or other factors that could materially affect the Company. However, management believes that a final resolution will not have a material adverse impact on the Company. Prospective investors are also referred to the other risks identified from time to time in the Company's reports and registration statements filed with the Securities and Exchange Commission.*

## OVERVIEW

Calpine is a leading independent power company engaged in the development, acquisition, ownership and operation of power generation facilities and the sale of electricity predominantly in the United States. We have experienced significant growth in all aspects of our business over the last five years. As of April 19, 2001, we own interests in 49 power plants having a net capacity of 5,837 megawatts. We also have 27 gas-fired projects under construction having a net capacity of 14,520 megawatts and have announced plans to develop 31 gas-fired projects (power plants and expansions of current facilities) with a net capacity of 17,785 megawatts. Upon completion of the projects under construction, we will have interests in 75 power plants located in 21 states and Alberta, Canada, having a net capacity of 20,357 megawatts. Of this total generating capacity, 96% will be attributable to gas-fired facilities and 4% will be attributable to geothermal facilities. As a result of



our expansion program, our revenues, earnings and assets have grown significantly over the last five years, as shown in the table below.

| | 1996 | 2000 | Compound Annual Growth Rate |
|---|---|---|---|
| | (dollars in millions) | | |
| Total Revenue | $ 291.5 | $ 2,547.1 | 72% |
| Net Income | 14.8 | 372.6 | 124% |
| Total Assets | 1,245.0 | 10,323.2 | 70% |

Since our inception in 1984, we have developed substantial expertise in all aspects of the development, acquisition and operation of power generation facilities. We believe that the vertical integration of our extensive engineering, construction management, operations, fuel management, power marketing and financing capabilities provides us with a competitive advantage to successfully implement our acquisition and development program and has contributed to our significant growth over the past five years.

## THE MARKET

The power industry represents the third largest industry in the United States, with an estimated end-user market of over $215 billion of electricity sales in 2000 produced by an aggregate base of power generation facilities with a capacity of approximately 860,000 megawatts. In response to increasing customer demand for access to low-cost electricity and enhanced services, new regulatory initiatives have been and are continuing to be adopted at both the state and federal level to increase competition in the domestic power generation industry. The power generation industry historically has been largely characterized by electric utility monopolies producing electricity from old, inefficient, high-cost generating facilities selling to a captive customer base. Industry trends and regulatory initiatives have transformed the existing market into a more competitive market where end-users purchase electricity from a variety of suppliers, including non-utility generators, power marketers, public utilities and others.

There is a significant need for additional power generating capacity throughout the United States, both to satisfy increasing demand, as well as to replace old and inefficient generating facilities. Due to environmental and economic considerations, we believe this new capacity will be provided predominantly by gas-fired facilities. We believe that these market trends will create substantial opportunities for efficient, low-cost power producers that can produce and sell energy to customers at competitive rates.

In addition, as a result of a variety of factors, including deregulation of the power generation market, utilities, independent power producers and industrial companies are disposing of power generation facilities. To date, numerous utilities have sold or announced their intentions to sell their power generation facilities and have focused their resources on the transmission and distribution business segments. Many independent producers operating a limited number of power plants are also seeking to dispose of their plants in response to competitive pressures, and industrial companies are selling their power plants to redeploy capital in their core businesses.

## STRATEGY

Our strategy is to continue our rapid growth by capitalizing on the significant opportunities in the power market, primarily through our active development and acquisition programs. In pursuing our growth strategy, we utilize our management and technical knowledge to implement a fully integrated approach to the acquisition, development and operation of power generation facilities. This approach uses our expertise in design, engineering, procurement, finance, construction management, fuel and resource production, acquisition, operations and power marketing, which we believe provides us with a competitive advantage. The key elements of our strategy are as follows:

- *Development of new and expansion of existing power plants.* We are actively pursuing the development of new, and expansion of both baseload and peaking capacity at our existing, highly efficient, low-



cost, gas-fired power plants to replace old and inefficient generating facilities and meet the demand for new generation.

- *Acquisition of power plants.* Our strategy is to acquire power generating facilities that meet our stringent criteria, provide significant potential for revenue, cash flow and earnings growth and provide the opportunity to enhance the operating efficiencies of the plants.

- *Enhancement of existing power plants.* We continually seek to maximize the power generation and revenue potential of our operating assets and minimize our operating and maintenance expenses and fuel costs.

## RECENT DEVELOPMENTS

*Project Development and Construction.* On February 12, 2001, we announced that the Florida Public Service Commission approved a joint application filed by Calpine and Seminole Electric Cooperative, Inc. (“Seminole”), under which we will build the Osprey Energy Center to supply electric power to help meet Seminole’s members’ power needs.

*Acquisitions.* On April 3, 2001, we acquired all of the common shares of WRMS Engineering, Inc. (“WRMS”), a California-based engineering and architectural firm, through a stock-for-stock exchange in which WRMS shareholders received a total of 151,176 shares of Calpine common stock. The aggregate value of the transaction, which was accounted for under the purchase method, is approximately $7.8 million, including the assumed indebtedness of WRMS. WRMS is expected to provide services to support our c*Power unit, which provides highly reliable, critical power to industrial and high tech customers.

On April 11, 2001, we acquired the development rights from Enron North America for the 750-megawatt natural gas-fired Pastoria Energy Center planned for Kern County, California. The project was licensed by the California Energy Commission in December 2000. Construction will begin in June 2001 and commercial operation is scheduled for the summer of 2003.

On April 17, 2001, we acquired the development rights from Kirkland, Washington-based National Energy Systems Company for the 248-megawatt natural gas-fired Goldendale Energy Center planned for Goldendale, Washington. Energy generated from the Goldendale facility will be sold directly into the Northwest Power Pool. Construction commenced in April 2001, and energy deliveries are scheduled to begin July 1, 2002.

On April 17, 2001, we acquired assets of The Bayless Companies and its partners with reserves located in the western portion of the San Juan Basin in New Mexico. Currently 35 wells produce approximately 6 million cubic feet equivalent per day (“mmcfe/d”), 96 percent of which is natural gas.

On April 19, 2001, we completed our merger with Encal Energy Ltd. (“Encal”), a Calgary, Alberta-based natural gas and petroleum exploration and development company. Encal shareholders received, in exchange for each share of Encal common stock, 0.1493 shares of Calpine common equivalent shares (called “exchangeable shares”) of our subsidiary, Calpine Canada Holdings Ltd. A total of 16,603,633 exchangeable shares were issued to Encal shareholders in exchange for all of the outstanding shares of Encal common stock. Each exchangeable share is exchangeable for one share of Calpine common stock. The aggregate value of the transaction was approximately US $1.1 billion, including the assumed indebtedness of Encal. This transaction was accounted for as a pooling-of-interests. With the addition of Encal’s assets, which currently produce approximately 230 million cubic feet of gas equivalent (“mmcfe”) per day, net of royalties, our net production is expected to increase to 390 mmcfe per day in North America, enough to fuel approximately 2,300 megawatts of our power fleet.

*Issuance of Securities.* On February 15, 2001, we completed a public offering of $1.15 billion of our 8 1/2% Senior Notes due 2011. The Senior Notes due 2011 bear interest at 8 1/2% per year, are payable semi-annually, and mature on February 15, 2011.

*California Power Market.* The deregulation of the California power market has produced significant unanticipated results in the past year. The deregulation froze the rates that utilities can charge their retail customers in California and prohibited the utilities from buying power on a forward basis, while wholesale power prices were not subjected to limits.

In the past year, a series of factors have reduced the supply of power to California, which has resulted in wholesale power prices that have been significantly higher than historical levels. Several factors contributed to this increase. These included:

- significantly increased volatility in prices and supplies of natural gas;
- an unusually dry fall and winter in the Pacific Northwest, which reduced the amount of available hydroelectric power from that region (typically, California imports a portion of its power from this source);
- the large number of power generating facilities in California nearing the end of their useful lives, resulting in increased downtime (either for repairs or because they have exhausted their air pollution credits and replacement credits have become too costly to acquire on the secondary market); and
- continued obstacles to new power plant construction in California, which deprived the market of new power sources that could have, in part, ameliorated the adverse effects of the foregoing factors.

As a result of this situation, two major California utilities that are subject to the retail rate freeze, including Pacific Gas & Electric Company ("PG&E"), have faced wholesale prices that far exceed the retail prices they are permitted to charge. This has led to significant under-recovery of costs by these utilities. As a consequence, these utilities have defaulted under a variety of contractual obligations, including payment obligations to power generators. PG&E has defaulted on payment obligations to us under our long-term qualifying facility ("QF") contracts which are subject to federal regulation under the Public Utility Regulatory Policies Act of 1978, as amended ("PURPA"). The PG&E QF contracts are in place at eleven of our facilities and represent nearly 600 megawatts of electricity for northern California customers. (For additional information, including information on certain receivables, see Notes 15 and 20 of the Notes to Consolidated Financial Statements.)

We have continued to honor our contractual obligations to PG&E under our QF contracts. To date, we have refrained from pursuing our collection remedies with respect to PG&E's default, however, we have been actively involved with the California utilities, the California legislature, and other interested parties to develop legislation designed to stabilize energy prices through the application of a long-term energy pricing methodology (for a five-year period) in place of the short-term pricing methodology currently utilized under the QF contracts, as discussed above. We also expect further legislation to enable the California utilities to finance over a longer term the difference between the wholesale prices that have been paid and the retail prices they received during last fall and into this winter. We believe that this should enhance PG&E's ability to make payment of all past due amounts. However, management cannot predict the timing or ultimate outcome of the legislative process or the payment of amounts due under our contracts.

As this situation has deteriorated, California has taken steps to restore a predictable and reliable power market to the State. Recently, California adopted legislation permitting it to issue long-term revenue bonds to provide funding for wholesale purchases of power. The bonds will be repaid with the proceeds of payments by retail customers over time. The California Department of Water Resources ("DWR") sought bids for long-term power supply contracts. We successfully bid in that auction, and announced, as indicated below, that we have signed three significant long-term power supply contracts with DWR.

On February 7, 2001, we announced the signing of a 10-year, $4.6 billion fixed-price contract with DWR to provide electricity to the State of California. We committed to sell up to 1,000 megawatts of electricity, with initial deliveries of 200 megawatts starting October 1, 2001, and increasing to 1,000 megawatts by January 1, 2004. This contract will continue through 2011. The electricity will be sold directly to DWR on a 24-hour, 7-day-a-week basis.



On February 28, 2001, we announced the signing of two long-term power sales contracts with DWR. Under the terms of the first contract, a $5.2 billion, 10-year, fixed-price contract, we commit to sell up to 1,000 megawatts of generation. Initial deliveries are scheduled to begin July 1, 2001 with 200 megawatts and increase to 1,000 megawatts by as early as July 2002. Under the terms of the second contract, a 20-year contract totaling up to $3.1 billion, we will supply DWR with up to 495 megawatts of peaking generation, beginning with 90 megawatts as early as August 2001, and increasing up to 495 megawatts as early as August 2002.

On March 13, 2001, we announced the signing of a two-month deal to provide 555 megawatts of electricity to DWR from our new South

Point Energy Center during plant testing, effective immediately through May 15, 2001.

*PG&E Bankruptcy Proceedings.* On April 6, 2001, PG&E filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code. As of April 6, 2001, we had recorded approximately $266 million in accounts receivable with PG&E under our QF contracts, plus a $69 million note receivable not yet due and payable. We are currently selling power to PG&E pursuant to our long-term QF contracts, and PG&E is paying on a current basis for these purchases since its bankruptcy filing. We are confident that PG&E, through a successful reorganization, will be able to pay us for all past due power sales, in addition to electricity deliveries made on a going-forward basis. (For additional information, including information on certain receivables, see Notes 15 and 19 to the Consolidated Financial Statements).

*CPUC Proceedings Regarding QF Contract Pricing.* Our QF contracts with PG&E provide that the California Public Utilities Commission ("CPUC") has the authority to determine the appropriate utility "avoided cost" to be used to set energy payments for certain QF contracts, including those for all of our QF plants in California which sell power to PG&E. Section 390 of the California Public Utility Code provides QF s the option to elect to receive energy payments based on the California Power Exchange Corporation ("PX") market clearing price. In mid 2000, our QF facilities elected this option and were paid based upon the PX zonal day-ahead clearing price ("PX Price") from summer 2000 until January 19, 2001, when the PX ceased operating a day-ahead market. Since that time, the CPUC has ordered that the price to be paid for energy deliveries by QFs electing the PX Price shall be based on a natural gas cost-based "transition formula." The CPUC has conducted proceedings (R. 99-11-022) to determine whether the PX Price was the appropriate price for the energy component upon which to base payments to QFs which had elected the PX based pricing option. The CPUC has issued a proposed decision to the effect that the PX Price was the appropriate price for energy payments under the California Public Utility Code. However, a final decision has not been issued to date. Therefore, it is possible that the CPUC could order a payment adjustment based on a different energy price determination. We believe that the PX Price was the appropriate price for energy payments but there can be no assurance that this will be the outcome of the CPUC proceedings.

On March 28, 2001, the CPUC issued an order (Decision 01-03-067) (the "March 2001 Decision") proposing to change, on a prospective basis, the composition of the short run avoided cost ("SRAC") energy price formula, which is reset monthly, used by the California utilities in QF contracts. Prior to the March 2001 Decision, CPUC regulations calculated SRAC based on 50% Topock and 50% Malin border gas indices. In the March 2001 Decision, the CPUC changed this formulation to eliminate the prices at Topock from the SRAC formula. The March 2001 Decision is subject to challenges at the CPUC and the Federal Energy Regulatory Commission.

*FERC Investigation into California Wholesale Markets.* In response to the increase in wholesale energy prices in the California markets, on June 28, 2000, the Board of Governors of the California Independent System Operator (the "ISO"), which controls the long-distance high-voltage power lines that deliver electricity throughout California and adjoining states, reduced the price cap applicable to the ISO's wholesale energy and ancillary services markets from $750/ MWh to $500/ MWh. The ISO subsequently reduced the price cap to $250/MWh effective August 7, 2000. During this period, however, the PX maintained a separate price cap set at a much higher level applicable to the day-ahead and day-of markets administered by the PX. On August 23, 2000, the Federal Energy Regulatory Commission ("FERC") denied a complaint filed August 2, 2000 by San Diego Gas & Electric Company ("SDG&E") that sought to extend the ISO's



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$250/MWh price cap to all California energy and ancillary service markets, not just the markets administered by the ISO. However, in its order denying the relief sought by SDG&E, FERC instructed its staff to initiate an investigation of the California power markets and to report its findings to the FERC and held further hearing procedures in abeyance pending the outcome of this investigation. Under FERC regulations, QF contracts are exempt from regulation under the Federal Power Act, which is the legislation that provides the authority for FERC to investigate the California power markets and frame equitable relief with respect to the California wholesale markets. Therefore, any such relief will only apply to sales by Calpine in the short-term market. None of Calpine's receivables related to power produced under its long-term QF contracts with PG&E should be affected by any FERC findings pursuant to the proceedings described below. See "Government Regulation — Federal Energy Regulation — Federal Power Act Regulation."

On November 1, 2000, FERC released a Staff Report detailing the results of the Staff investigation, together with an "Order Proposing Remedies for California Wholesale Markets" (the "November 1 Order"). In the November 1 Order, FERC found that the California power market structure and market rules were seriously flawed, and that these flaws, together with short supply relative to demand, resulted in unusually high energy prices. The November 1 Order proposed specific remedies to the identified market flaws, including: (a) imposition of a so-called "soft" price cap at $150/ MWh to be applied to both the PX and ISO markets, which would allow bids above $150/MWh to be accepted, but would subject such bids to certain reporting obligations requiring sellers to provide cost data and/or identify applicable opportunity costs and specifying that such bids may not set the overall market clearing price; (b) elimination of the requirement that the California utilities sell into and buy from the PX; (c) establishment of independent non-stakeholder governing boards for the ISO and the PX; and (d) establishment of penalty charges for scheduling deviations outside of a prescribed range. In the November 1, Order FERC established October 2, 2000, the date 60 days after the filing of the SDG&E complaint, as the "refund effective date." Under the November 1 Order, rates charged for service after that date through December 31, 2002 will remain subject to refund if determined by FERC not to be just and reasonable. While FERC concluded that the Federal Power Act and prior court decisions interpreting that act strongly suggested that refunds would not be permissible for charges in the period prior to October 2, 2000, it noted that it was willing to explore proposals for equitable relief with respect to charges made in that period.

On December 15, 2000, FERC issued a subsequent order that affirmed in large measure the November 1 Order (the "December 15 Order").

Various parties have filed requests for administrative rehearing and for judicial review of aspects of FERC's December 15 Order. The outcome of these proceedings, and the extent to which FERC or a reviewing court may revise aspects of the December 15 Order or the extent to which these proceedings may result in a refund of or reduction in the amounts charged by the Company's subsidiaries for power sold in the ISO and PX markets, cannot be determined at this time.

## DESCRIPTION OF FACILITIES

At April 19, 2001, Calpine had interests in 49 power generation facilities representing 5,837 megawatts of net capacity. Of these 49 projects, 30 are gas-fired power plants with a net capacity of 4,987 megawatts, and 19 are geothermal power generation facilities with a net capacity of 850 megawatts. We also have 26 gas-fired projects and one project expansion currently under construction with a net capacity of 14,520 megawatts, and have announced the development of 24 additional power plants and seven project expansions with a net capacity of 17,785 megawatts. Each of the power generation facilities currently in operation produces electricity for sale to a utility or other third-party end user. Thermal energy produced by the gas-fired cogeneration facilities is sold to governmental and industrial users.

The gas-fired and geothermal power generation projects in which we have an interest produce electricity and thermal energy that are typically sold pursuant to long-term power sales agreements. Revenue from a power sales agreement usually consists of two components: energy payments and capacity payments. Energy payments are based on a power plant's net electrical output where payment rates may be determined by a schedule of prices covering a fixed number of years under the power sales agreement, after which payment rates are usually indexed to the fuel costs of the contracting utility or to general inflation indices. Capacity



payments are based on a power plant's net electrical output and/or its available capacity. Energy payments are made for each kilowatt hour of energy delivered, while capacity payments, under certain circumstances, are made whether or not any electricity is delivered.

Upon completion of our projects under construction, we will provide operating and maintenance services for 71 of the 75 power plants in which we have an interest. Such services include the operation of power plants, geothermal steam fields, wells and well pumps, gas fields, gathering systems and gas pipelines. We also supervise maintenance, materials purchasing and inventory control, manage cash flow, train staff and prepare operating and maintenance manuals for each power generation facility that we operate. As a facility develops an operating history, we analyze its operation and may modify or upgrade equipment or adjust operating procedures or maintenance measures to enhance the facility's reliability or profitability. These services are sometimes performed under the terms of an operating and maintenance agreement pursuant to which we are generally reimbursed for certain costs, paid an annual operating fee and may also be paid an incentive fee based on the performance of the facility. The fees payable to us are generally subordinated to any lease payments or debt service obligations of financing for the project.

In order to provide fuel for the gas-fired power generation facilities in which we have an interest, natural gas reserves are acquired or natural gas is purchased from third parties under supply agreements. We attempt to structure a gas-fired power facility's fuel supply agreement so that gas costs have a direct relationship to the fuel component of revenue energy payments. See "Item 2 — Properties" for further discussion of our gas reserves.

We currently hold interests in geothermal leaseholds in Lake and Sonoma Counties in northern California ("The Geysers") that produce steam that is supplied to geothermal power generation facilities owned by us for use in producing electricity.

Certain power generation facilities in which we have an interest have been financed primarily with project financing that is structured to be serviced out of the cash flows derived from the sale of electricity and thermal energy produced by such facilities and provides that the obligations to pay interest and principal on the loans are secured almost solely by the capital stock or partnership interests, physical assets, contracts and/or cash flow attributable to the entities that own the facilities. The lenders under non-recourse project financing generally have no recourse for repayment against us or any of our assets or the assets of any other entity other than foreclosure on pledges of stock or partnership interests and the assets attributable to the entities that own the facilities.

Substantially all of the power generation facilities in which we have an interest are located on sites which we own or are leased on a long-term basis. See "Item 2 — Properties."

Set forth below is certain information regarding our operating power plants, plants under construction, and announced development projects as of April 19, 2001.

| | | Megawatts | | | |
|---|---|---|---|---|---|
| | Number of Plants | Baseload Capacity | Peaking Capacity | Calpine Net Interest Baseload | Calpine Net Interest Peaking |

| | | | | | |
|---|---|---|---|---|---|
| In operation | | | | | |
| Geothermal power plants | 19 | 850 | 850 | 850 | 850 |
| Gas-fired power plants | 30 | 4,708 | 5,746 | 3,995 | 4,987 |
| Under construction | | | | | |
| New facilities | 26 | 13,935 | 15,938 | 12,324 | 14,160 |
| Expansion projects (one) | — | — | 360 | — | 360 |
| Announced development | | | | | |
| New facilities | 24 | 13,931 | 17,142 | 13,665 | 16,853 |
| Expansion projects (seven) | — | 322 | 932 | 322 | 932 |
| | 99 | 33,746 | 40,968 | 31,156 | 38,142 |



**OPERATING POWER PLANTS**

| Power Plant | State or Province | Baseload Capacity (MW) | Peaking Capacity (MW) | Calpine Interest Percentage | Calpine Net Interest Baseload (MW) | Calpine Net Interest Peaking (MW) | 2000 Generation MWh |
|---|---|---|---|---|---|---|---|
| **Geothermal Power Plants** | | | | | | | |
| Sonoma County (12 plants) | CA | 512.0 | 512.0 | 100.0% | 512.0 | 512.0 | 3,488,792 |
| Lake County (2 plants) | CA | 145.0 | 145.0 | 100.0% | 145.0 | 145.0 | 944,441 |
| Calistoga | CA | 73.0 | 73.0 | 100.0% | 73.0 | 73.0 | 533,531 |
| Sonoma | CA | 53.0 | 53.0 | 100.0% | 53.0 | 53.0 | 380,478 |
| West Ford Flat | CA | 27.0 | 27.0 | 100.0% | 27.0 | 27.0 | 217,231 |
| Bear Canyon | CA | 20.0 | 20.0 | 100.0% | 20.0 | 20.0 | 146,193 |
| Aidlin | CA | 20.0 | 20.0 | 100.0% | 20.0 | 20.0 | 149,074 |
| Total Geothermal Power Plants | | 850.0 | 850.0 | | 850.0 | 850.0 | 5,859,740 |
| **Gas-Fired Power Plants** | | | | | | | |
| Pasadena Power Plant | TX | 751.0 | 787.0 | 100.0% | 751.0 | 787.0 | 3,150,018 |
| Broad River Energy Center | SC | — | 541.0 | 100.0% | — | 541.0 | 21,451 |
| Hidalgo Energy Center | TX | 502.0 | 502.0 | 78.5% | 394.1 | 394.1 | 981,498 |
| Texas City Power Plant | TX | 465.0 | 471.0 | 100.0% | 465.0 | 471.0 | 3,413,022 |
| Clear Lake Power Plant | TX | 335.0 | 412.0 | 100.0% | 335.0 | 412.0 | 2,937,853 |
| Rumford Power Plant | ME | 237.0 | 251.0 | 100.0% | 237.0 | 251.0 | 105,256 |
| Tiverton Power Plant | RI | 240.0 | 240.0 | 100.0% | 240.0 | 240.0 | 292,798 |
| Gordonsville Power Plant | VA | 233.0 | 238.0 | 50.0% | 116.5 | 119.0 | 119,287 |
| Lockport Power Plant | NY | 177.0 | 198.0 | 11.4% | 20.1 | 22.5 | 186,826 |
| DePere Energy Center | WI | — | 180.0 | 100.0% | — | 180.0 | 53,631 |
| Morris Power Plant | IL | 155.0 | 177.5 | 86.0% | 134.0 | 146.4 | 535,323 |
| Bayonne Power Plant (1) | NJ | | | | | | 105,277 |
| Dighton Power Plant | MA | 162.0 | 168.0 | 100.0% | 162.0 | 168.0 | 839,746 |
| Androscoggin Energy Center | ME | 160.0 | 160.0 | 32.3% | 51.7 | 51.7 | 53,979 |
| Auburndale Power Plant | FL | 143.0 | 153.0 | 100.0% | 143.0 | 153.0 | 512,118 |
| Grays Ferry Power Plant | PA | 143.0 | 148.0 | 40.0% | 57.2 | 59.2 | 417,485 |
| Gilroy Power Plant | CA | 112.0 | 131.0 | 100.0% | 112.0 | 131.0 | 917,348 |
| Pryor Power Plant | OK | 109.0 | 124.0 | 80.0% | 87.2 | 99.2 | 321,146 |
| Sumas Power Plant | WA | 120.0 | 122.0 | 50.0% | 60.0 | 61.0 | 1,087,658 |
| Parlin Power Plant | NJ | 89.0 | 118.0 | 80.0% | 71.2 | 94.4 | 347,002 |
| King City Power Plant | CA | 103.0 | 115.0 | 100.0% | 103.0 | 115.0 | 914,807 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Kennedy International Airport Power Plant ("KIAC") | NY | 95.0 | 105.0 | 100.0% | 95.0 | 105.0 | 231,404 |
| Pittsburg Power Plant | CA | 64.0 | 71.0 | 100.0% | 64.0 | 71.0 | 438,444 |
| Newark Power Plant | NJ | 47.0 | 58.0 | 80.0% | 37.6 | 46.4 | 271,164 |
| Bethpage Power Plant | NY | 52.0 | 53.7 | 100.0% | 52.0 | 53.7 | 384,448 |
| Greenleaf 1 Power Plant | CA | 50.0 | 50.0 | 100.0% | 50.0 | 50.0 | 379,205 |
| Greenleaf 2 Power Plant | CA | 50.0 | 50.0 | 100.0% | 50.0 | 50.0 | 358,961 |
| Stony Brook Power Plant | NY | 36.0 | 40.0 | 100.0% | 36.0 | 40.0 | 125,455 |
| Watsonville Power Plant | CA | 29.0 | 30.0 | 100.0% | 29.0 | 30.0 | 219,516 |
| Agnews Power Plant | CA | 26.5 | 28.6 | 100.0% | 26.5 | 28.6 | 113,798 |
| Philadelphia Water Project | PA | 22.0 | 23.0 | 66.4% | 14.6 | 15.3 | 890 |
| Total Gas-Fired Power Plants | | 4,707.5 | 5,745.8 | | 3,994.7 | 4,986.5 | 19,836,814 |
| Total Operating Power Plants | | 5,557.5 | 6,595.8 | | 4,844.7 | 5,836.5 | 25,696,554 |

(1) We sold our 7.5% interest in this facility on March 21, 2001.



**PROJECTS UNDER CONSTRUCTION AND ANNOUNCED DEVELOPMENT**

| Power Plant | Power Generation Technology | State or Province | Baseload Capacity (MW) | Peaking Capacity (MW) | Calpine Interest Percentage | Calpine Net Interest Baseload (MW) | Calpine Net Interest Peaking (MW) |
|---|---|---|---|---|---|---|---|
| **Projects Under Construction** | | | | | | | |
| Acadia Energy Center | Gas | LA | 1,080.0 | 1,239.0 | 50.0% | 540.0 | 619.5 |
| Oneta Energy Center | Gas | OK | 960.3 | 1,137.8 | 100.0% | 960.3 | 1,137.8 |
| Freestone Energy Center | Gas | TX | 1,002.8 | 1,051.6 | 100.0% | 1,002.8 | 1,051.6 |
| Delta Energy Center | Gas | CA | 798.0 | 874.0 | 50.0% | 399.0 | 437.0 |
| Baytown Power Plant | Gas | TX | 704.0 | 834.0 | 100.0% | 704.0 | 834.0 |
| Decatur Energy Center | Gas | AL | 659.0 | 794.0 | 100.0% | 659.0 | 794.0 |
| Morgan Energy Center | Gas | AL | 660.0 | 790.0 | 100.0% | 660.0 | 790.0 |
| Magic Valley Generating Station | Gas | TX | 687.0 | 750.0 | 100.0% | 687.0 | 750.0 |
| Hermiston Power Project | Gas | OR | 530.0 | 630.0 | 100.0% | 530.0 | 630.0 |
| Channel Energy Center | Gas | TX | 519.0 | 628.0 | 100.0% | 519.0 | 628.0 |
| Aries Power Plant | Gas | MO | 516.0 | 591.0 | 50.0% | 258.0 | 295.5 |
| Washington Parish Energy Center | Gas | LA | 509.0 | 565.0 | 100.0% | 509.0 | 565.0 |
| South Point Energy Center | Gas | AZ | 526.0 | 555.0 | 100.0% | 526.0 | 555.0 |
| Los Medanos Energy Center | Gas | CA | 493.0 | 555.0 | 100.0% | 493.0 | 555.0 |
| Sutter Energy Center | Gas | CA | 516.0 | 547.0 | 100.0% | 516.0 | 547.0 |
| Lost Pines 1 Energy Center | Gas | TX | 522.0 | 545.0 | 50.0% | 261.0 | 272.5 |
| Ontelaunee Energy Center | Gas | PA | 511.0 | 541.0 | 100.0% | 511.0 | 541.0 |
| Westbrook Energy Center | Gas | ME | 487.0 | 525.0 | 100.0% | 487.0 | 525.0 |
| Corpus Christi Energy Center | Gas | TX | 522.7 | 522.7 | 100.0% | 522.7 | 522.7 |
| Carville Energy Center | Gas | LA | 522.7 | 522.7 | 100.0% | 522.7 | 522.7 |
| RockGen Energy Center | Gas | WI | — | 460.0 | 100.0% | — | 460.0 |
| Broad River Energy Center Expansion | Gas | SC | — | 360.0 | 100.0% | — | 360.0 |
| Calgary Energy Centre | Gas | AB | 250.0 | 300.0 | 100.0% | 250.0 | 300.0 |
| Goldendale Energy Center | Gas | WA | 248.0 | 268.0 | 100.0% | 248.0 | 268.0 |
| Santa Rosa Energy Center | Gas | FL | 252.0 | 252.0 | 100.0% | 252.0 | 252.0 |

| | | | | | | | |
|---|---|---|---|---|---|---|---|
| Hog Bayou Energy Center | Gas | AL | 246.6 | 246.6 | 66.7% | 164.5 | 164.5 |
| Pine Bluff Energy Center | Gas | AR | 213.3 | 213.3 | 66.7% | 142.3 | 142.3 |
| Total Projects Under Construction | | | 13,935.4 | 16,297.7 | | 12,324.3 | 14,520.1 |
| **Announced Development** | | | | | | | |
| Blue Heron Energy Center | Gas | FL | 1,080.0 | 1,239.0 | 100.0% | 1,080.0 | 1,239.0 |
| Lawrence Energy Center | Gas | OH | 850.0 | 1,100.0 | 100.0% | 850.0 | 1,100.0 |
| East Altamont Energy Center | Gas | CA | 820.0 | 1,065.0 | 100.0% | 820.0 | 1,065.0 |
| Deer Park Energy Center | Gas | TX | 773.0 | 1,007.0 | 100.0% | 773.0 | 1,007.0 |
| Haywood Energy Center | Gas | TN | 800.0 | 915.0 | 100.0% | 800.0 | 915.0 |
| Lone Oak Energy Center | Gas | MS | 800.0 | 915.0 | 100.0% | 800.0 | 915.0 |
| Augusta Energy Center | Gas | GA | 750.0 | 850.0 | 100.0% | 750.0 | 850.0 |
| Hillabee Energy Center | Gas | AL | 710.0 | 770.0 | 100.0% | 710.0 | 770.0 |
| Pastoria Energy Center | Gas | CA | 750.0 | 750.0 | 100.0% | 750.0 | 750.0 |
| Fremont Energy Center | Gas | OH | 550.0 | 700.0 | 100.0% | 550.0 | 700.0 |
| Wawayanda Energy Center | Gas | NY | 530.0 | 630.0 | 100.0% | 530.0 | 630.0 |
| Columbia Energy Center | Gas | SC | 450.0 | 620.0 | 100.0% | 450.0 | 620.0 |
| Otay Mesa Generating Project | Gas | CA | 540.0 | 618.0 | 100.0% | 540.0 | 618.0 |
| Teayawa Energy Center | Gas | CA | 530.0 | 608.0 | 100.0% | 530.0 | 608.0 |
| Rocky Mountain Energy Center | Gas | CO | 455.0 | 600.0 | 100.0% | 455.0 | 600.0 |
| Riverside Energy Center | Gas | WI | 450.0 | 600.0 | 100.0% | 450.0 | 600.0 |
| Osprey Energy Center | Gas | FL | 530.0 | 590.0 | 100.0% | 530.0 | 590.0 |
| Metcalf Energy Center | Gas | CA | 532.5 | 578.7 | 50.0% | 266.3 | 289.4 |
| Thompson Creek Energy Center | Gas | LA | 500.0 | 575.0 | 100.0% | 500.0 | 575.0 |
| Hammond Energy Center | Gas | IN | 500.0 | 550.0 | 100.0% | 500.0 | 550.0 |
| Mt. Vernon Energy Center | Gas | IN | 522.7 | 522.7 | 100.0% | 522.7 | 522.7 |
| Towantic Energy Center | Gas | CT | 508.0 | 508.0 | 100.0% | 508.0 | 508.0 |
| California Peakers (4 projects) | Gas | CA | — | 495.0 | 100.0% | — | 495.0 |



| Power Plant | Power Generation Technology | State or Province | Baseload Capacity (MW) | Peaking Capacity (MW) | Calpine Interest Percentage | Calpine Net Interest Baseload (MW) | Calpine Net Interest Peaking (MW) |
|---|---|---|---|---|---|---|---|
| Zion Energy Center | Gas | IL | — | 495.0 | 100.0% | — | 495.0 |
| Colorado Energy Center | Gas | CO | — | 336.0 | 100.0% | — | 336.0 |
| Pine Bluff Energy Center Expansion | Gas | AR | 246.6 | 246.6 | 100.0% | 246.6 | 246.6 |
| Auburndale Expansion | Gas | FL | — | 115.0 | 100.0% | — | 115.0 |
| DePere Energy Center Expansion | Gas | WI | 75.0 | 75.0 | 100.0% | 75.0 | 75.0 |
| Total Announced Development | | | 14,252.8 | 18,074.0 | | 13,986.6 | 17,784.7 |

## PROJECT DEVELOPMENT AND ACQUISITIONS OF POWER PROJECTS

We are actively engaged in the development and acquisition of power generation projects. We have historically focused principally on the development and acquisition of interests in gas-fired and geothermal power projects, although we also consider projects that utilize other power generation technologies. We have significant expertise in a variety of power generation technologies and have substantial capabilities in each aspect of the development and acquisition process, including design, engineering, procurement, construction management, fuel and resource acquisition and management, power marketing, financing and operations.

***Acquisitions***

We will consider the acquisition of an interest in operating projects as well as projects under development where we would assume responsibility for completing the development of the project. In the acquisition of power generation facilities, we generally seek to acquire an ownership interest in facilities that offer us attractive opportunities for revenue and earnings growth, and that permit us to assume sole responsibility for the operation and maintenance of the facility. In evaluating and selecting a project for acquisition, we consider a variety of factors, including the type of power generation technology utilized, the location of the project, the terms of any existing power or thermal energy sales agreements, gas supply and transportation agreements and wheeling agreements, the quantity and quality of any geothermal or other natural resource involved, and the actual condition of the physical plant. In addition, we assess the past performance of an operating project and prepare financial projections to determine the profitability of the project. We generally seek to obtain a significant equity interest in a project and to obtain the operation and maintenance contract for that project.

***Project Development***

The development of power generation projects involves numerous elements, including evaluating and selecting development opportunities, designing and engineering the project, obtaining power sales agreements, acquiring necessary land rights, permits and fuel resources, obtaining financing and managing construction. We intend to focus primarily on development opportunities where we are able to capitalize on our expertise in implementing an innovative and fully integrated approach to project development in which we control the entire development process. Utilizing this approach, we believe that we are able to enhance the value of our projects throughout each stage of development in an effort to maximize our return on investment.

We are pursuing the development of highly efficient, low-cost power plants to provide competitively priced and environmentally friendly power to electricity markets. We intend to sell all or a portion of the power generated by such plants into the competitive market through a portfolio of short, medium and long-term power sales agreements.

*Projects Under Construction*

*Acadia Energy Center*. On March 6, 2000, we announced that we entered into a partnership agreement with Cleco Midstream Resources, an affiliate of Pineville, Louisiana-based Cleco Corporation, to participate in the Acadia Energy Center. The partners plan to build, own and operate the 1,239-megawatt natural gas-fired energy center near Eunice, Louisiana. We have a 620-megawatt net interest in this facility. Construction began in mid 2000 and commercial operation for the energy center is expected in May 2002. On October 20,



2000, we jointly announced with Cleco Corporation the signing of a 20-year contract with Aquila Energy, a wholly owned subsidiary of UtiliCorp United, for 580 megawatts of the output of the jointly owned Acadia Energy Center. Under terms of a tolling agreement, starting July 1, 2002, Aquila Energy will supply the natural gas needed to generate 580 megawatts of electricity and will own and market the produced power.

*Oneta Energy Center.* On July 20, 2000, we acquired the development rights to construct, own and operate the Oneta Energy Center from Panda Energy, International, Inc. Oneta is a 1,138-megawatt natural gas-fired energy center under construction in Coweta, Oklahoma, southeast of Tulsa. We anticipate that the Oneta Energy Center will commence commercial operation in July 2002.

*Freestone Energy Center.* On June 15, 2000, we announced that we acquired the rights to develop, build, own and operate the Freestone Energy Center from New Orleans, Louisiana-based Entergy Corp. Freestone is a 1,052-megawatt natural gas-fired energy center located in Freestone County, Texas, near Fairfield, about 80 miles southeast of Dallas. Construction commenced in August 2000 and commercial operation is expected to begin in the summer of 2002.

*Delta Energy Center*. In February 1999, we, together with Bechtel Enterprises, announced plans to develop an 874-megawatt gas-fired cogeneration energy center in Pittsburg, California in which we have a 437-megawatt net interest. The Delta Energy Center will provide steam and electricity to the nearby Dow Chemical Company facility and market the excess electricity into the California power market. Construction began in April 2000 and we expect commercial operation to commence in May 2002.

*Baytown Power Plant.* In October 1999, we announced plans to build, own and operate an 834-megawatt gas-fired cogeneration power plant at Bayer Corporation’s chemical facility in Baytown, Texas. The Baytown Power Plant will supply Bayer with all of its electric and steam requirements for 20 years and market excess electricity into the Texas wholesale power market. Construction commenced in early 2000 and commercial operation is expected to commence in late 2001.

*Decatur Energy Center.* On February 2, 2000, we announced plans to build, own and operate a 794-megawatt gas-fired cogeneration energy center at Solutia Inc.’s Decatur, Alabama chemical facility. Under a 20-year agreement, Solutia will lease a portion of the facility to meet its electricity needs and purchase its steam requirements from us. Excess power from the facility will be sold into the Southeastern Wholesale Power Market under a variety of short, medium and long-term contracts. We will also build a new intrastate natural gas pipeline to fuel the energy center. Construction began in September 2000 and commercial operation is expected to commence in the summer of 2002.

*Morgan Energy Center.* On June 27, 2000, we announced plans to build, own and operate a natural gas-fired cogeneration energy center at the BP Amoco chemical facility in Decatur, Alabama. The Morgan Energy Center will generate approximately 790 megawatts of electricity in addition to supplying steam for BP Amoco's facility. Construction began in September 2000 and we expect commercial operation to commence in September 2002.

*Magic Valley Generating Station.* In May 1998, we announced that we signed a 20-year power sales agreement to provide electricity to the Magic Valley Electric Cooperative, Inc. of Mercedes, Texas beginning in 2001. The power will be supplied by our Magic Valley Generating Station, a 750-megawatt natural gas-fired generating station under construction in Edinburg, Texas. Magic Valley Electric Cooperative Inc., a 51,000-member non-profit electric cooperative, initially will purchase from 250 to 400 megawatts of capacity, with an option to purchase additional capacity. We are marketing additional capacity to other wholesale customers, initially targeting south Texas. Construction commenced in the spring of 1999 with commercial operation scheduled to begin in the fall of 2001.

*Hermiston Power Project.* On January 28, 2000, we acquired the development rights for the Hermiston Power Project, a 630-megawatt gas-fired cogeneration power facility located near Hermiston, Oregon. Construction commenced in the summer of 2000 and we anticipate that commercial operation of the facility will commence in the summer of 2002.



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*Channel Energy Center.* In October 1999, we announced we had executed a letter of intent that gave us the exclusive right to negotiate with LYONDELL-CITGO Refining LP to build, own and operate a 628-megawatt gas-fired cogeneration energy center at the LYONDELL-CITGO refinery in Houston, Texas. The Channel Energy Center will supply all of the electricity and steam requirements for 20 years to the refinery. Construction began in early 2000 and simple-cycle commercial operation is expected to begin in the summer of 2001.

*Aries Power Plant.* On January 14, 2000, we acquired a 296-megawatt net interest in the Aries Power Plant, a 591-megawatt natural gas-fired plant currently under construction near Pleasant Hill, Missouri, from a subsidiary of Aquila Energy Corporation. Construction started in the fall of 1999 and simple-cycle commercial operation is scheduled to begin in the spring of 2001. The majority of the facility's output will be sold to Missouri Public Service through May 2005. Thereafter, power will be sold into the Southwest Power Pool and the Southeast Electric Reliability Counsel regional power markets.

*Washington Parish Energy Center.* On January 26, 2001, we announced the acquisition of the development rights from Cogentrix, an independent power company based in North Carolina, for the 565-megawatt Washington Parish Energy Center, located near Bogalusa, Louisiana. We are managing construction of the facility, which began in January 2001, and will operate the facility when it enters commercial operation in late 2002.

*South Point Energy Center.* In May 1998, we announced that we had entered into a long-term lease agreement with the Fort Mojave Indian Tribe to develop a 555-megawatt gas-fired energy center on the tribe's reservation in Mojave County, Arizona. Construction commenced in August 1999 and we anticipate that the South Point Energy Center will begin operation in June 2001. In accordance with a five-year power sales agreement with the Imperial Irrigation District ("IID"), we will deliver 150 megawatts of electricity from the South Point Energy Center to IID's southern California electric customers beginning in May 2002. Thereafter, the electricity generated will be sold to the Arizona, Nevada and California power markets.

*Los Medanos Energy Center.* In September 1999, we finalized an agreement with Enron North America for the development rights of a 555-megawatt gas-fired energy center in Pittsburg, California. We expect that the Los Medanos Energy Center will be California's second newly constructed power facility since deregulation of the California power market in 1998. Construction commenced in September 1999 and commercial operation is expected to begin in the summer of 2001. The facility will provide electricity and industrial steam totaling approximately 65 megawatts to USS-POSCO Industries under a long-term agreement. The remaining output will be sold into the California power market.

*Sutter Energy Center.* In February 1997, we announced plans to develop a 547-megawatt gas-fired combined-cycle energy center in Sutter County, in northern California. The Sutter Energy Center is expected to be California's first newly constructed energy center since deregulation of the California power market in 1998. Construction commenced in the third quarter of 1999 and the Sutter Energy Center is expected to begin commercial operation in the summer of 2001. In accordance with an agreement we entered into with the Sacramento Municipal Utility District ("SMUD") on January 18, 2000, the Sutter Energy Center will provide 150 megawatts of electricity to SMUD's customer base for a five-year period beginning with the plant's startup.

*Lost Pines 1 Energy Center.* In September 1999, we entered into definitive agreements with Austin, Texas-based GenTex Power Corporation, the power generation affiliate of the Lower Colorado River Authority, to build a 545-megawatt gas-fired energy center in Bastrop County, Texas. We have a 273-megawatt net interest in this facility. Construction began in October 1999 and commercial operation is expected to begin in mid 2001. Upon commercial operation, GenTex will take half of the electrical output for sale to its customers, and we will market the remaining energy to the Texas power market.

*Ontelaunee Energy Center.* In June 1999, we announced that we had acquired the rights to develop a 541-megawatt gas-fired energy center

in Ontelaunee Township in eastern Pennsylvania. Construction began in July 2000 and commercial operation is estimated to commence in mid 2002. Output from the Ontelaunee



Energy Center will be sold into the Pennsylvania/ New Jersey/ Maryland ("PJM") power pool and pursuant to bilateral contracts.

*Westbrook Energy Center.* In February 1999, we acquired from Genesis Power Corporation, a New England based power developer, the development rights to a 525-megawatt gas-fired combined-cycle energy center located in Westbrook, Maine. Construction commenced in early 1999 and commercial operation is scheduled for the spring of 2001. It is anticipated that the output generated by the Westbrook Energy Center will be sold into the New England power market and to wholesale and retail customers in the northeastern United States.

*Corpus Christi Energy Center.* The Corpus Christi Energy Center is a 523-megawatt combined-cycle, cogeneration energy center located in Corpus Christi, Texas. Construction began in June 2000 and we expect commercial operation to begin in June 2002. In March 1999, a long-term energy services agreement was executed with CITGO Refining and Chemicals Company, L.P. ("CITGO") under which CITGO will purchase from the Corpus Christi Energy Center all of the steam and electricity that it requires but does not internally generate at its Corpus Christi refinery.

*Carville Energy Center.* The Carville Energy Center is a 523-megawatt combined-cycle, cogeneration energy center located in St. Gabriel, Louisiana. Construction of the facility began in October 2000 and commercial operation is expected to commence in May 2002. On December 28, 1999, a long-term energy services agreement was executed with Cos-Mar Inc. ("Cos-Mar") under which Cos-Mar will purchase from the Carville Energy Center all of the steam and electric power (if allowed under applicable regulations) that it requires but does not internally generate at its St. Gabriel chemical plant.

*RockGen Energy Center.* The 460-megawatt RockGen Energy Center is located in the town of Christiana in Dane County, Wisconsin. Construction began in April 2000 and we expect commercial operation to commence in May 2001. On August 10, 1998, IES Utilities, Wisconsin Power and Light Company and Interstate Power Company (collectively the "Alliant Utilities") entered into a long-term power purchase agreement with the RockGen Energy Center. In January 1999, the RockGen Energy Center also entered into a long-term tolling arrangement with Duke Energy Trading and Marketing, L.L.C.

*Broad River Energy Center Expansion.* This expansion, the second phase of construction of the Broad River Energy Center, involves the installation of two additional combustion turbines capable of producing an additional 360 megawatts of peaking power. Construction is expected to be completed in the summer of 2001. On November 15, 2000, we announced that our wholly owned subsidiary, SkyGen Energy LLC ("SkyGen"), entered into an agreement to supply CP&L Energy ("CP&L") additional power produced from the Broad River Energy Center Expansion project.

*Calgary Energy Centre.* On April 20, 2000, we announced plans to construct the Calgary Energy Centre. Scheduled to begin commercial operation in late 2002, the 300-megawatt combined-cycle, natural gas-fired facility was the first independent power project announced in the Calgary area, and represents our first investment in the Canadian power industry.

*Goldendale Energy Center.* In April 2001, we acquired the rights to develop a 248-megawatt combined-cycle energy center located in Goldendale, Washington. Construction of the Goldendale Energy Center began in the spring of 2001 and commercial operation is expected to commence in the summer of 2002. Energy generated by the facility will be sold directly into the Northwest Power Pool.

*Santa Rosa Energy Center.* The Santa Rosa Energy Center is a 252-megawatt combined-cycle energy center located near Pensacola, Florida. Construction began in September 2000 and commercial operation is expected to commence in September 2002.

*Hog Bayou Energy Center.* We have a 165-megawatt net interest in this 247-megawatt gas-fired combined-cycle facility located in Mobile, Alabama. Construction of the facility began in July 1999 and commercial operation is expected to commence in July 2001.

*Pine Bluff Energy Center.* We have a 142-megawatt interest in this 213-megawatt steam and electric power cogeneration energy center near Pine Bluff, Arkansas. Construction began in September 1999 and we



anticipate the facility will commence commercial operation in August 2001. On November 25, 1998, International Paper entered into a long-term energy services agreement under which International Paper will purchase from the Pine Bluff Energy Center all of the steam and electric power (if allowed under applicable regulations) that it requires but does not internally generate at its Pine Bluff mill.

*Announced Development Projects*

*Blue Heron Energy Center.* On January 11, 2000 we announced plans to build, own and operate a 1,239-megawatt gas-fired cogeneration energy center in Indian River County, Florida outside of Vero Beach. We anticipate that construction will commence in early 2002 and that commercial operation of the facility will commence in mid 2004.

*Lawrence Energy Center.* On October 23, 2000, we announced that we entered into a project development agreement to build, own and operate a 1,100-megawatt natural gas-fired energy center to be located on the Ohio River in Hamilton Township in Lawrence County, Ohio. The proposed Lawrence Energy Center will represent a $510 million investment, with a target commercial operation date of 2004.

*East Altamont Energy Center.* On December 12, 2000, we announced that we are considering plans to develop and operate a new energy-efficient electricity-generating facility, the proposed $550 million East Altamont Energy Center, located in the northeastern corner of Alameda County in northern California. We are preparing technical studies for the proposed 1,065-megawatt facility. Upon completion of licensing through the California Energy Commission ("CEC"), construction would begin in June 2002, with commercial operation beginning in June 2004.

*Deer Park Energy Center.* In March 2001, we announced plans to build, own and operate a 1,000-megawatt natural gas-fired energy center in Deer Park, Texas. The proposed Deer Park Energy Center will supply steam to Shell Chemical Company and electric power generated at the facility will be sold on the wholesale market. Construction is expected to begin in mid 2001, with the first phase of the project operational by early 2003 and the second, larger phase operational by mid 2004.

*Haywood Energy Center.* On July 19, 2000, we announced we will develop, construct and own a natural gas-fired, combined-cycle power generation facility in Haywood County, Tennessee. The 915-megawatt facility is scheduled to begin commercial operation in late 2003.

*Lone Oak Energy Center.* On February 22, 2000, we announced plans to build, own and operate the Lone Oak Energy Center, a 915-megawatt gas-fired cogeneration facility in Lowndes County, Mississippi. We anticipate that construction will commence in the spring of 2002 and that commercial operation of the facility will commence in mid 2004.

*Augusta Energy Center.* On January 17, 2001, our wholly owned subsidiary, SkyGen, announced plans to build, own and operate an 850-megawatt natural gas-fired cogeneration energy center in Augusta, Georgia. The proposed Augusta Energy Center will supply energy to DSM Chemicals North America, Inc. for use in its production processes. Construction is expected to begin in the third quarter of 2001, with an estimated commercial operation date of August 2003.

*Hillabee Energy Center.* On February 24, 2000, we announced plans to build, own and operate the Hillabee Energy Center, a 770-megawatt gas-fired cogeneration facility in Tallapoosa County, Alabama. We anticipate that construction will commence in mid 2001 and that commercial operation of the facility will commence in mid 2003.

*Pastoria Energy Center.* In April 2001, we acquired the rights to develop the 750-megawatt Pastoria Energy Center, a combined-cycle project planned for Kern County, California. Construction is expected to begin in the summer of 2001, with commercial operation scheduled to begin in the summer of 2003.

*Fremont Energy Center.* On May 23, 2000, we announced the acquisition of development rights to build, own and operate a 700-megawatt gas-fired facility to be located near Fremont, Ohio. Construction is scheduled to begin in September of 2001 and we expect commercial operation to commence in the fall of 2003.



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*Wawayanda Energy Center.* On March 23, 2000, we announced plans to build, own and operate the Wawayanda Energy Center, a 630-megawatt gas-fired facility to be located near Middletown, New York. We anticipate that construction will begin in late 2002 and commercial operation will begin in late 2004.

*Columbia Energy Center.* The Columbia Energy Center is a 620-megawatt combined-cycle cogeneration project located in Columbia, South Carolina. We expect construction will commence in June 2001 and commercial operation will begin in June 2003. On August 15, 2000, a long-term energy services agreement was executed with Eastman Chemical Company ("Eastman") under which Eastman will purchase from the Columbia Energy Center all of the steam and electric power (if allowed under applicable regulations) that it requires but does not internally generate at its Columbia chemical plant.

*Otay Mesa Generating Project.* On December 18, 2000, we announced with PG&E Corporation an agreement under which we will acquire the rights to construct the Otay Mesa Generating Project in San Diego County. In accordance with the terms of the agreement, we will build, own and operate the 618-megawatt generating facility, and PG&E Corporation's National Energy Group will contract for up to 250 megawatts of the project's output. Construction is expected to begin in the summer of 2001 and commercial operation is scheduled for the fall of 2003.

*Teayawa Energy Center.* On June 29, 2000, we announced that we secured the rights to develop, build, own and operate the Teayawa Energy Center, a 608-megawatt natural gas-fired power generating facility near the town of Thermal in Riverside County, California through a development agreement with Adair International Oil and Gas, Inc. The Teayawa Energy Center will be sited on the Torres Martinez Desert Cahuilla Indians' land through a long-term lease agreement with the Torres Martinez. Construction is scheduled to begin in early 2002 and commercial operation is expected in early 2004.

*Rocky Mountain Energy Center.* In March 2001, we announced plans to build, own and operate the Rocky Mountain Energy Center, a 600-megawatt combined-cycle facility to be located near the town of Hudson in Weld County, Colorado. We expect construction will commence in early 2002 and commercial operation is scheduled for mid 2004. The Rocky Mountain Energy Center will supply Xcel Energy, formerly Public Service Co. of Colorado, with up to 600 megawatts of electricity for a period of ten years.

*Riverside Energy Center.* Our proposed 600-megawatt Riverside Energy Center will be located near Beloit, Wisconsin. Construction of the Riverside Energy Center is expected to begin during the fourth quarter of 2001, with commercial operation starting in mid 2003. On February 13, 2001, we announced that our wholly owned subsidiary, SkyGen Energy LLC, entered into a ten-year agreement to supply Wisconsin Power & Light Company 453 megawatts of electric capacity and energy from the proposed Riverside Energy Center.

*Osprey Energy Center.* On January 11, 2000, we announced plans to build, own and operate the Osprey Energy Center, a 590-megawatt gas-fired cogeneration energy center near the city of Auburndale, Florida. On February 12, 2001, the Florida Public Service Commission approved the application for the facility, which will be built adjacent to our existing power facility, the Auburndale Power Plant. We anticipate that construction will commence in the fall of 2001 and commercial operation of the facility will commence in the fall of 2003. In accordance with an agreement we entered into with Tampa, Florida-based Seminole, the Osprey Energy Center will supply electric power to help meet Seminole's member systems' power needs for a period of 17 years beginning in June 2003.

*Metcalf Energy Center.* In February 1999, we, together with Bechtel Enterprises, announced plans to develop, own and operate a 579-megawatt gas-fired cogeneration energy center in San Jose, California. We have a 289-megawatt net interest in this facility. The CEC is currently considering whether to override a November 2000 vote by the San Jose City Council denying a request to change the zoning designation of the land at the proposed site. We cannot predict at this time whether the CEC will in fact override this vote. If the CEC does elect to override this vote, we expect the CEC review, licensing and public hearing process would be completed in late 2001. We would then anticipate that construction would commence, subject to any further delays, and that commercial operation of the facility would commence in late 2003. We plan to sell the electricity generated by the Metcalf Energy Center into the California power market.



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*Thompson Creek Energy Center.* The Thompson Creek Energy Center is a 575-megawatt combined- cycle, cogeneration project located in Louisiana. We expect construction to begin in the spring of 2002 and anticipate that the facility will commence commercial operation in the spring of 2004.

*Hammond Energy Center.* The Hammond Energy Center is a 550-megawatt facility to be located in Indiana. Construction is scheduled to begin in mid 2002 and commercial operation is expected in mid 2004.

*Mt. Vernon Energy Center.* The Mt. Vernon Energy Center is a 523-megawatt facility to be located in Indiana. Construction is scheduled to begin in the second quarter of 2002 and commercial operation is expected to commence in the second quarter of 2004.

*Towantic Energy Center.* In November 1999, we acquired the development rights to build, own and operate the Towantic Energy Center. The Towantic Energy Center is a 508-megawatt gas-fired cogeneration plant located in Oxford, Connecticut. This power plant will market its electricity via bilateral contracts into the New England region. In February 2000, a town-wide referendum in the Town of Oxford, Connecticut approved the sale of the town-owned land for the Towantic Energy Center. Construction is estimated to commence in mid 2002 and commercial operation is expected in March 2004.

*California Peakers (4 projects).* Eleven GE LM6000 turbines will be installed at four of our operating gas-fired power plants in California to increase peaking capacity by a total of 495 megawatts. Six turbines will be installed at the Gilroy Power Plant, three at the Watsonville Power Plant, one at the Greenleaf 2 Power Plant and one at the King City Power Plant.

*Zion Energy Center.* The Zion Energy Center is a 495-megawatt simple-cycle facility located in Zion, Illinois. Construction is scheduled to begin in August 2001 with commercial operation expected to commence in July 2002. In December 2000, a contract was executed for the long-term sale of capacity from the Zion Energy Center.

*Colorado Energy Center.* The Colorado Energy Center, a 336-megawatt peaking facility, will be located east of Denver in the city of Aurora. Under the terms of a ten-year agreement, Xcel Energy, formerly Public Service Co. of Colorado, will have dispatch rights for all of the capacity and energy produced by the facility. Construction is scheduled to begin in early 2002, with commercial operation starting in mid 2003.

*Pine Bluff Energy Center Expansion.* Construction on this 247-megawatt expansion of the Pine Bluff Energy Center is expected to

commence in mid 2002 and operation is anticipated to begin in mid 2004.

*Auburndale Expansion.* On July 6, 2000, we announced the addition of 115 megawatts of peaking capacity to the natural gas-fired cogeneration facility located in Auburndale, Florida. Construction is scheduled to begin in August 2001 with commercial operation expected to commence in June 2002.

*DePere Energy Center Expansion.* This second phase of construction of the DePere Energy Center will convert the DePere, Wisconsin facility from a 180-megawatt simple-cycle gas-fired combustion turbine to a 255-megawatt combined-cycle cogeneration system. The expansion is expected to be complete by January 2004. All electric capacity and energy will be sold to the Wisconsin Public Service Corporation under a 25-year power purchase agreement. Nicolet Paper Company, an affiliate of International Paper Company, will purchase the cogenerated steam.

**OIL AND GAS PROPERTIES**

*Montis Niger.* In January 1997, we purchased Montis Niger, Inc., a gas production and pipeline company operating primarily in the Sacramento Basin in northern California, which we subsequently renamed Calpine Gas Company. As of December 31, 2000, Calpine Gas Company owned proven natural gas reserves and leasehold acreage, and operated an 80-mile pipeline delivering gas to our Greenleaf 1 and 2 Power Plants. We currently supply the majority of the fuel requirements for the Greenleaf 1 and 2 Power Plants.

*Calpine Natural Gas Company.* In October 1999, we purchased Sheridan Energy, Inc. ("Sheridan"), a natural gas exploration and production company operating in northern California and the Gulf Coast region, which we subsequently renamed Calpine Natural Gas Company ("CNGC"). CNGC's oil and gas properties



are primarily natural gas and are located in strategic markets where we are developing low-cost natural gas supplies and proprietary pipeline systems in support of our natural gas-fired power plants.

*Vintage Petroleum.* In December 1999, we completed the acquisition of Vintage Petroleum, Inc.'s ("Vintage") interest in the Rio Vista Gas Unit and related areas, representing primarily natural gas reserves located in the Sacramento Basin in northern California. As a result of this acquisition and the Sheridan acquisition, we own a 99.5% working interest in the Rio Vista Gas Unit and certain development acreage in northern California.

*Western Gas Resources.* On February 4, 2000, we acquired 100% of the stock of Western Gas Resources California ("Western") from Western Gas Resources, Inc. Western's assets include the 130-mile Steelhead natural gas pipeline and the remaining interest in the Sacramento River Gas System natural gas pipeline, now 100% owned by us.

*Gulf of Mexico.* In June 2000, we acquired an interest in the East Cameron, High Island and South Pelto fields in the Gulf of Mexico which includes 10 producing wells and 5 drilling locations enhanced with 3-D seismic, one of which has already been successfully drilled.

*Calpine Canada Natural Gas, Ltd.* On July 5, 2000, we purchased Calgary-based Quintana Minerals Canada Corp. ("QMCC"), a natural gas exploration and production company, whose reserves are located in British Columbia, Alberta and Saskatchewan provinces in Canada. We subsequently changed its name to Calpine Canada Natural Gas, Ltd. ("CCNG"). The assets include interests in 1,300 wells.

Additionally, in November 2000, we acquired TriGas Exploration Inc. ("TriGas"), of Calgary, Alberta, an exploration company focused on developing and producing gas reserves in south-central Alberta. We subsequently merged the company into CCNG. The assets include an interest in 74 producing wells located in the Acme, Lone Pine, Lone Pine South and Irricana fields, 48,000 net acres of undeveloped lands, two compression facilities, a 26.6% working interest in the Crossfield gas processing plant located near the fields, and a majority interest in 63 miles of pipeline that conduct the gas to two nearby gas-fired power generation facilities.

*Colorado and Gulf Coast.* In July 2000, we acquired natural gas assets in the Piceance Basin, Colorado and onshore Gulf Coast from a privately-held Houston, Texas-based company. The assets include 126 producing wells, 79,000 acres of undeveloped lands, and 195 potential drilling locations with historical success rates of over 90 percent.

*Encal Energy Ltd.* On April 19, 2001, we completed our merger with Encal, a Calgary, Alberta-based natural gas and petroleum exploration and development company. Encal shareholders received, in exchange for each share of Encal common stock, 0.1493 shares of Calpine common equivalent shares (called "exchangeable shares") of the Company's subsidiary, Calpine Canada Holdings Ltd. A total of 16,603,633 exchangeable shares were issued to Encal shareholders in exchange for all of the outstanding shares of Encal common stock. Each exchangeable share is exchangeable for one share of Calpine common stock. The aggregate value of the transaction was approximately US $1.1 billion, including the assumed indebtedness of Encal. The transaction was accounted for as a pooling-of-interests. Upon completion of the acquisition, we gained approximately 1.0 trillion cubic feet equivalent of proved and provable natural gas resources, net of royalties. This

transaction also provides access to firm gas transportation capacity from western Canada to California and the eastern U.S., and an accomplished management team capable of leading our business expansion in Canada. With the addition of Encal's assets, which currently produce approximately 230 mmcfe per day, net of royalties, our net production is expected to increase to 390 mmcfe per day in North America, enough to fuel approximately 2,300 megawatts of our power fleet.

## GOVERNMENT REGULATION

We are subject to complex and stringent energy, environmental and other governmental laws and regulations at the federal, state and local levels in connection with the development, ownership and operation of our energy generation facilities. Federal laws and regulations govern transactions by electric and gas utility



companies, the types of fuel which may be utilized by an electricity-generating plant, the type of energy which may be produced by such a plant and the ownership of a plant. State utility regulatory commissions must approve the rates and, in some instances, other terms and conditions under which public utilities sell at retail electricity that they have purchased from independent producers. Under certain circumstances where specific exemptions are otherwise unavailable, state utility regulatory commissions may have broad jurisdiction over non-utility electric power plants. Energy producing projects also are subject to federal, state and local laws and administrative regulations which govern the emissions and other substances produced, discharged or disposed of by a plant and the geographical location, zoning, land use and operation of a plant. Applicable federal environmental laws typically have both state and local enforcement and implementation provisions. These environmental laws and regulations generally require that a wide variety of permits and other approvals be obtained before the commencement of construction or operation of an energy-producing facility and that the facility then operate in compliance with such permits and approvals.

### *Federal Energy Regulation*

*PURPA*

The enactment of the PURPA and the adoption of regulations thereunder by the FERC provided incentives for the development of cogeneration facilities and small power production facilities (those utilizing renewable fuels and having a capacity of less than 80 megawatts).

A domestic electricity-generating project must be a QF under FERC regulations in order to take advantage of certain rate and regulatory incentives provided by PURPA. PURPA exempts owners of QFs from the Public Utility Holding Company Act of 1935, as amended ("PUHCA"), and exempts QFs from most provisions of the Federal Power Act (the "FPA") and, except under certain limited circumstances, state laws concerning rate or financial regulation. These exemptions are important to us and our competitors. We believe that each of the electricity-generating projects in which we own an interest and which operates as a QF power producer currently meets the requirements under PURPA necessary for QF status.

PURPA provides two primary benefits to QFs. First, QFs generally are relieved of compliance with extensive federal and state regulations that control the financial structure of an electricity-generating plant and the prices and terms on which electricity may be sold by the plant. Second, the FERC's regulations promulgated under PURPA require that electric utilities purchase electricity generated by QFs at a price based on the purchasing utility's "avoided cost," and that the utility sell back-up power to the QF on a non-discriminatory basis. The term "avoided cost" is defined as the incremental cost to an electric utility of electric energy or capacity, or both, which, but for the purchase from QFs, such utility would generate for itself or purchase from another source. The FERC regulations also permit QFs and utilities to negotiate agreements for utility purchases of power at rates lower than the utility's avoided costs. While public utilities are not explicitly required by PURPA to enter into long-term power sales agreements, PURPA helped to create a regulatory environment in which it has been common for long-term agreements to be negotiated.

In order to be a QF, a cogeneration facility must produce not only electricity, but also useful thermal energy for use in an industrial or commercial process for heating or cooling applications in certain proportions to the facility's total energy output and must meet certain energy efficiency standards. A geothermal facility may qualify as a QF if it produces less than 80 megawatts of electricity. Finally, a QF (including a geothermal QF or other qualifying small power producer) must not be controlled or more than 50% owned by one or more electric utilities or by most electric utility holding companies, or one or more subsidiaries of such a utility or holding company or any combination thereof.

We endeavor to develop our projects, monitor compliance by the projects with applicable regulations and choose our customers in a manner which minimizes the risks of any project losing its QF status. Certain factors necessary to maintain QF status are, however, subject to the risk of events outside our control. For example, loss of a thermal energy customer or failure of a thermal energy customer to take required amounts of thermal energy from a cogeneration facility that is a QF could cause the facility to fail requirements regarding the level of useful thermal energy output. Upon the occurrence of such an event, we would seek to

replace the thermal energy customer or find another use for the thermal energy which meets PURPA's requirements, but no assurance can be given that this would be possible.

If one of the facilities in which we have an interest should lose its status as a QF, the project would no longer be entitled to the exemptions from PUHCA and the FPA. This could also trigger certain rights of termination under the facility's power sales agreement, could subject the facility to rate regulation as a public utility under the FPA and state law and could result in us inadvertently becoming an electric utility holding company by owning more than 10% of the voting securities of, or controlling, a facility that would no longer be exempt from PUHCA. This could cause all of our remaining projects to lose their qualifying status, because QFs may not be controlled or more than 50% owned by such electric utility holding companies. Loss of QF status may also trigger defaults under covenants to maintain QF status in the projects' power sales agreements, steam sales agreements and financing agreements and result in termination, penalties or acceleration of indebtedness under such agreements such that loss of status may be on a retroactive or a prospective basis.

Under the Energy Policy Act of 1992, if a facility can be qualified as an exempt wholesale generator ("EWG"), meaning that all of its output is sold for resale rather than to end users, it will be exempt from PUHCA even if it does not qualify as a QF. Therefore, another response to the loss or potential loss of QF status would be to apply to have the project qualified as an EWG. However, assuming this changed status would be permissible under the terms of the applicable power sales agreement, rate approval from FERC would be required. In addition, the facility would be required to cease selling electricity to any retail customers (such as the thermal energy customer) to retain its EWG status and could become subject to state regulation of sales of thermal energy. See "Public Utility Holding Company Regulation."

Currently, Congress is considering proposed legislation that would amend PURPA by eliminating the requirement that utilities purchase electricity from QFs at avoided costs. We do not know whether such legislation will be passed or what form it may take. We believe that if any such legislation is passed, it would apply only to new projects, and we believe it would not affect our existing QFs. There can be no assurance, however, that any legislation passed would not adversely impact our existing projects.

*Public Utility Holding Company Regulation*

Under PUHCA, any corporation, partnership or other legal entity which owns or controls 10% or more of the outstanding voting securities of a "public utility company", or a company which is a "holding company" for a public utility company, is subject to registration with the Securities and Exchange Commission ("SEC") and regulation under PUHCA, unless eligible for an exemption. A holding company of a public utility company that is subject to registration is required by PUHCA to limit its utility operations to a single integrated utility system and to divest any other operations not functionally related to the operation of that utility system. Approval by the SEC is required for nearly all important financial and business dealings of a registered holding company. Under PURPA, most QFs are not public utility companies under PUHCA.

The Energy Policy Act of 1992, among other things, amends PUHCA to allow EWGs, under certain circumstances, to own and operate non-QF electric generating facilities without subjecting those producers to registration or regulation under PUHCA. The effect of such amendments has been to enhance the development of non-QFs which do not have to meet the fuel, production and ownership requirements of PURPA. We believe that these amendments benefit us by expanding our ability to own and operate facilities that do not qualify for QF status. However, they have also resulted in increased competition by allowing utilities and their affiliates to develop such facilities which are not subject to the constraints of PUHCA.

*Federal Natural Gas Transportation Regulation*

We have an ownership interest in 38 gas-fired cogeneration plants in operation or under construction. The cost of natural gas is ordinarily the largest expense of a gas-fired project and is critical to the project's economics. The risks associated with using natural gas can include the need to arrange transportation of the gas from great distances, including obtaining removal, export and import authority if the gas is transported from Canada; the possibility of interruption of the gas supply or transportation (depending on the quality of the gas reserves purchased or dedicated to the project, the financial and operating strength of the gas supplier,



whether firm or non-firm transportation is purchased and the operations of the gas pipeline); and obligations to take a minimum quantity of gas and pay for it (i.e., take-and-pay obligations).

Pursuant to the Natural Gas Act, FERC has jurisdiction over the transportation and storage of natural gas in interstate commerce. With respect to most transactions that do not involve the construction of pipeline facilities, regulatory authorization can be obtained on a self-implementing basis. However, interstate pipeline rates and terms and conditions for such services are subject to continuing FERC oversight.

*Federal Power Act Regulation*

Under the FPA, FERC is authorized to regulate the transmission of electric energy and the sale of electric energy at wholesale in interstate commerce. Unless otherwise exempt, any person that owns or operates facilities used for such purposes is considered a “public utility” subject to FERC jurisdiction. FERC regulation under the FPA includes approval of the disposition of utility property, authorization of the issuance of securities by public utilities, regulation of the rates, terms and conditions for the transmission or sale of electric energy at wholesale in interstate commerce, the regulation of interlocking directorates, a uniform system of accounts and reporting requirements for public utilities.

FERC regulations implementing PURPA provide that a QF is exempt from regulation under the foregoing provisions of the FPA. An EWG is not exempt from the FPA and therefore an EWG that makes sales of electric energy at wholesale in interstate commerce is subject to FERC regulation as a “public utility.” However, many of the regulations which customarily apply to traditional public utilities have been waived or relaxed for power marketers, EWGs and other non-traditional public utilities that lack market power. EWGs are regularly granted authorization to charge market-based rates, blanket authority to issue securities, and waivers of certain FERC requirements pertaining to accounts, reports and interlocking directorates. Such action is intended to implement FERC’s policy to foster a more competitive wholesale power market.

Many of the generating projects in which we own an interest are operated as QFs and are therefore exempt from FERC regulation under the FPA. However, several of our generating projects are or will be EWGs subject to FERC jurisdiction under the FPA. Several of our affiliates have been granted authority to engage in sales at market-based rates and to issue securities, and have also been granted the customary waivers of FERC regulations available to non-traditional public utilities; however we cannot assure that such authorities or waivers will be granted in the future to other affiliates.

***State Regulation***

State public utility commissions (“PUCs”) have historically had broad authority to regulate both the rates charged by, and the financial activities of, electric utilities operating in their states and to promulgate regulation for implementation of PURPA. Since a power sales agreement becomes a part of a utility’s cost structure (generally reflected in its retail rates), power sales agreements with independent electricity producers, such as EWGs, are potentially under the regulatory purview of PUCs and in particular the process by which the utility has entered into the power sales agreements. If a PUC has approved the process by which a utility secures its power supply, a PUC is generally inclined to “pass through” the expense associated with a power purchase agreement with an independent power producer to the utility’s retail customers. However, a regulatory commission under certain circumstances may disallow the full reimbursement to a utility for the cost to purchase power from a QF or an EWG. In addition, retail sales of electricity or thermal energy by an independent power producer may be subject to PUC regulation depending on state law. Independent power producers which are not QFs under PURPA, or EWGs pursuant to the Energy Policy Act of 1992, are considered to be public utilities in many states and are subject to broad regulation by a PUC, ranging from requirement of certificate of public convenience and necessity to regulation of organizational, accounting, financial and other corporate matters. States may assert jurisdiction over the siting and construction of electricity-generating facilities including QFs and EWGs and, with the exception of QFs, over the issuance of securities and the sale or other transfer of assets by these facilities.

State PUCs also have jurisdiction over the transportation of natural gas by local distribution companies (“LDCs”). Each state’s regulatory laws are somewhat different; however, all generally require the LDC to



obtain approval from the PUC for the construction of facilities and transportation services if the LDC’s generally applicable tariffs do not cover the proposed transaction. LDC rates are usually subject to continuing PUC oversight.

***Regulation of Canadian Gas***

The Canadian natural gas industry is subject to extensive regulation by governmental authorities. At the federal level, a party exporting gas from Canada must obtain an export license from the Canadian National Energy Board (“NEB”). The NEB also regulates Canadian pipeline transportation rates and the construction of pipeline facilities. Gas producers also must obtain a removal permit or license from provincial authorities before natural gas may be removed from the province, and provincial authorities may regulate intra-provincial pipeline and gathering systems. In addition, a party importing natural gas into the United States first must obtain an import authorization from the U.S. Department of Energy.

***Environmental Regulations***

The exploration for and development of geothermal resources and natural gas, and the construction and operation of wellfields, pipelines and power projects, are subject to extensive federal, state and local laws and regulations adopted for the protection of the environment and to regulate land use. The laws and regulations applicable to us primarily involve the discharge of emissions into the water and air and the use of water, but can also include wetlands preservation, endangered species, waste disposal and noise regulations. These laws and regulations in many cases require a lengthy and complex process of obtaining licenses, permits and approvals from federal, state and local agencies.

Noncompliance with environmental laws and regulations can result in the imposition of civil or criminal fines or penalties. In some instances, environmental laws also may impose clean-up or other remedial obligations in the event of a release of pollutants or contaminants

into the environment. The following federal laws are among the more significant environmental laws as they apply to us. In most cases, analogous state laws also exist that may impose similar, and in some cases more stringent, requirements on us as those discussed below.

*Clean Air Act*

The Federal Clean Air Act of 1970 (the "Clean Air Act") provides for the regulation, largely through state implementation of federal requirements, of emissions of air pollutants from certain facilities and operations. As originally enacted, the Clean Air Act sets guidelines for emissions standards for major pollutants (i.e., sulfur dioxide and nitrogen oxide) from newly built sources. In late 1990, Congress passed the Clean Air Act Amendments (the "1990 Amendments"). The 1990 Amendments attempt to reduce emissions from existing sources, particularly previously exempted older power plants. We believe that all of our operating plants are in compliance with federal performance standards mandated for such plants under the Clean Air Act and the 1990 Amendments.

*Clean Water Act*

The Federal Clean Water Act (the "Clean Water Act") establishes rules regulating the discharge of pollutants into waters of the United States. We are required to obtain a wastewater and storm water discharge permit for wastewater and runoff, respectively, from certain of our facilities. We believe that, with respect to our geothermal operations, we are exempt from newly promulgated federal storm water requirements. We believe that we are in material compliance with applicable discharge requirements of the Clean Water Act.

*Resource Conservation and Recovery Act*

The Resource Conservation and Recovery Act ("RCRA") regulates the generation, treatment, storage, handling, transportation and disposal of solid and hazardous waste. We believe that we are exempt from solid waste requirements under RCRA. However, particularly with respect to our solid waste disposal practices at the power generation facilities and steam fields located at The Geysers, we are subject to certain solid waste



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requirements under applicable California laws. We believe that our operations are in material compliance with such laws.

*Comprehensive Environmental Response, Compensation, and Liability Act*

The Comprehensive Environmental Response, Compensation and Liability Act of 1980, as amended ("CERCLA" or "Superfund"), requires cleanup of sites from which there has been a release or threatened release of hazardous substances and authorizes the United States Environmental Protection Agency to take any necessary response action at Superfund sites, including ordering potentially responsible parties ("PRPs") liable for the release to take or pay for such actions. PRPs are broadly defined under CERCLA to include past and present owners and operators of, as well as generators of wastes sent to, a site. As of the present time, we are not subject to liability for any Superfund matters. However, we generate certain wastes, including hazardous wastes, and send certain of our wastes to third party waste disposal sites. As a result, there can be no assurance that we will not incur liability under CERCLA in the future.

## RISK FACTORS

**See "Risk Factors" section under "Item 7 — Management's Discussion and Analysis of Financial Condition and Results of Operations" included in Exhibit IV of this report.**

## EMPLOYEES

As of December 31, 2000, we employed 2,126 people, of whom 33 were represented by collective bargaining agreements. We have never experienced a work stoppage or strike, and we consider relations with our employees to be good.



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**Exhibit II.**

**Item 2. *Properties***

Our principal executive office located in San Jose, California is held under leases that expire through 2011, and we also lease offices in Pleasanton, California; Houston, Texas; Boston, Massachusetts and Northbrook, Illinois. We hold additional leases for our Construction

Management office in Folsom, California, our Turbine Maintenance Group office in LaPorte, Texas, our Plant Optimization Group office in Fort Collins, Colorado, our c*Power office in Pleasanton, California, our Project Development office in Tampa, Florida, our Government Affairs office in Washington, D.C. and our Natural Gas Operations offices in Houston, TX, Denver, Colorado and Calgary, Alberta.

We have leasehold interests in 105 leases comprising 21,217 acres of federal, state and private geothermal resource lands in The Geysers area in northern California. In the Glass Mountain and Medicine Lake areas in northern California, we hold leasehold interests in 18 leases comprising approximately 25,028 acres of federal geothermal resource lands.

In general, under these leases, we have the exclusive right to drill for, produce and sell geothermal resources from these properties and the right to use the surface for all related purposes. Each lease requires the payment of annual rent until commercial quantities of geothermal resources are established. After such time, the leases require the payment of minimum advance royalties or other payments until production commences, at which time production royalties are payable. Such royalties and other payments are payable to landowners, state and federal agencies and others, and vary widely as to the particular lease. The leases are generally for initial terms varying from 10 to 20 years or for so long as geothermal resources are produced and sold. Certain of the leases contain drilling or other exploratory work requirements. In certain cases, if a requirement is not fulfilled, the lease may be terminated and in other cases additional payments may be required. We believe that our leases are valid and that we have complied with all the requirements and conditions material to the continued effectiveness of the leases. A number of our leases for undeveloped properties may expire in any given year. Before leases expire, we perform geological evaluations in an effort to determine the resource potential of the underlying properties. We cannot assure that we will decide to renew any expiring leases.

Based on independent petroleum engineering reports of Netherland, Sewell & Associates, Inc., McDaniel & Associates Consultants, Ltd. and Gilbert Laustsen Jung Associates, Ltd., as of December 31, 2000, utilizing year end product prices and costs held constant, our proved oil and natural gas reserve volumes, in millions of barrels (“MMBbls”) and billion cubic feet (“Bcf”) and associated future net reserves, undiscounted and discounted at 10% (“PV 10”) before future income taxes, are as follows:

| | As of December 31, 2000 | | | |
|---|---|---|---|---|
| | **Oil (MMBbls)** | **Gas (Bcf)** | **Undiscounted** | **PV 10** |
| | | | **(in millions)** | **(in millions)** |
| **United States** | | | | |
| Proved developed | 2.6 | 268 | $2,760 | $1,387 |
| Proved undeveloped | 0.9 | 65 | 580 | 304 |
| Total | 3.5 | 333 | $3,340 | $1,691 |
| **Canada** | | | | |
| Proved developed | 32.9 | 391 | $3,552 | $2,085 |
| Proved undeveloped | 13.8 | 146 | 1,248 | 733 |
| Total | 46.7 | 537 | $4,800 | $2,818 |
| **Consolidated Total** | | | | |
| Proved developed | 35.5 | 659 | $6,312 | $3,472 |
| Proved undeveloped | 14.8 | 211 | 1,828 | 1,037 |
| Total | 50.3 | 870 | $8,140 | $4,509 |

Proved oil and natural gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in



future years from known reservoirs under existing economic and operating conditions. Estimated future development costs associated with proved non-producing and proved undeveloped reserves as of December 31, 2000 totaled approximately $209.2 million.

The following table sets forth our interest in undeveloped acreage, developed acreage and productive wells in which we own a working interest as of December 31, 2000. Productive wells are wells in which we have a working interest and are capable of producing oil or natural gas. Gross represents the total number of acres or wells in which we own a working interest. Net represents our proportionate working interest resulting from our ownership in the gross acres or wells.

| | Undeveloped Acres | | Developed Acres | | Productive Wells | |
|---|---|---|---|---|---|---|
| | Gross | Net | Gross | Net | Gross | Net |
| **United States** | | | | | | |
| Arkansas | — | — | 8,823 | 3,967 | 35 | 15 |
| California | 30,143 | 23,755 | 77,308 | 73,261 | 155 | 130 |
| Colorado | 24,078 | 18,813 | 28,721 | 16,803 | 39 | 39 |
| Louisiana | 42,558 | 41,542 | 28,323 | 27,860 | 37 | 13 |
| Mississippi | 350 | 277 | 10,125 | 4,584 | 16 | 4 |
| Montana | 9,890 | 7,458 | 1,280 | 640 | 2 | 1 |
| Oklahoma | 4,765 | 953 | 29,878 | 13,938 | 88 | 20 |
| Texas | 17,481 | 7,123 | 21,587 | 9,815 | 134 | 49 |
| Wyoming | 47,936 | 35,584 | — | — | — | — |
| Offshore Louisiana | 6,250 | 6,250 | 8,750 | 8,750 | 5 | 5 |
| Offshore Texas | — | — | 5,760 | 3,142 | 10 | 5 |
| Total United States | 183,451 | 141,755 | 220,555 | 162,760 | 521 | 281 |
| **Canada** | 2,972,725 | 1,846,577 | 1,182,055 | 609,768 | 5,222 | 1,347 |
| **Consolidated Total** | 3,156,176 | 1,988,332 | 1,402,610 | 772,528 | 5,743 | 1,628 |

In connection with the Texas City, Clear Lake and Pasadena Power Plants, we lease an aggregate of 48 acres. We own 40 gross acres and 38 net acres in Edinburg, Texas where we are constructing the Magic Valley Power Plant. We own 77 acres in Sutter County, California, on which the Greenleaf 1 Power Plant is located. We own 78 acres in Dane County, Wisconsin, on which the RockGen Energy Center is being constructed. We own 49 acres in Zion, Illinois, on which the Zion Energy Center will be constructed. We own 40 acres in Iberville Parish, Louisiana, on which the Carville Energy Center is being constructed. See “Item 1 — Business — Description of Facilities” for a description of the other leased or owned properties in which we have an interest. We believe that our properties are adequate for our current operations.



**Exhibit III.**

**Item 6.** ***Selected Financial Data***

**(in thousands, except earnings per share and ratio data)**

| | Years Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 1996 | 1997 | 1998 | 1999 | 2000 |
| **Statement of operations data (1):** | | | | | |
| **Revenue:** | | | | | |
| Electric generation and marketing revenue | $ 202,264 | $ 237,277 | $ 511,360 | $ 783,482 | $ 2,072,974 |
| Oil and gas production and marketing revenue | 76,978 | 95,282 | 101,921 | 155,983 | 444,462 |
| Income from unconsolidated investments in power projects | 6,537 | 15,819 | 25,240 | 36,593 | 24,639 |
| Other revenue | 5,753 | 23,140 | 12,125 | 7,426 | 5,026 |
| Total revenue | 291,532 | 371,518 | 650,646 | 983,484 | 2,547,101 |
| Cost of revenue | 209,214 | 236,974 | 466,026 | 664,649 | 1,700,133 |
| Gross profit | 82,318 | 134,544 | 184,620 | 318,835 | 846,968 |
| Project development expense | 3,867 | 7,537 | 7,165 | 10,712 | 27,556 |
| General and administrative expense | 17,154 | 21,604 | 30,024 | 55,667 | 102,551 |

| | | | | | |
|---|---|---|---|---|---|
| Income from operations | 61,297 | 105,403 | 147,431 | 252,456 | 716,861 |
| Interest expense | 46,996 | 66,787 | 95,732 | 103,248 | 74,683 |
| Distributions on trust preferred securities | — | — | — | 2,565 | 44,210 |
| Other income | (5,697) | (14,744) | (8,642) | (29,215) | (40,678) |
| Income before provision for income taxes | 19,998 | 53,360 | 60,341 | 175,858 | 638,646 |
| Provision for income taxes | 5,204 | 20,035 | 21,183 | 68,058 | 264,809 |
| Income before extraordinary charge | 14,794 | 33,325 | 39,158 | 107,800 | 373,837 |
| Extraordinary charge, net of tax benefit of $—,$—, $441, $793 and $796 | — | — | 641 | 1,150 | 1,235 |
| Net income | $ 14,794 | $ 33,325 | $ 38,517 | $ 106,650 | $ 372,602 |
| Basic earnings per common share: | | | | | |
| Weighted average shares of common stock outstanding | 118,726 | 175,159 | 176,725 | 225,375 | 281,070 |
| Income before extraordinary charge | $ 0.12 | $ 0.19 | $ 0.22 | $ 0.48 | $ 1.33 |
| Extraordinary charge | $ — | $ — | $ — | $ (0.01) | $ — |
| Net income | $ 0.12 | $ 0.19 | $ 0.22 | $ 0.47 | $ 1.33 |
| Diluted earnings per common share: | | | | | |
| Weighted average shares of common stock outstanding before dilutive effect of certain trust preferred securities | 135,171 | 184,601 | 185,067 | 238,706 | 297,507 |
| Income before extraordinary charge and dilutive effect of certain trust preferred securities | $ 0.11 | $ 0.18 | $ 0.21 | $ 0.45 | $ 1.26 |
| Dilutive effect of certain trust preferred securities (2) | $ — | $ — | $ — | $ — | $ (0.06) |
| Income before extraordinary charge | $ 0.11 | $ 0.18 | $ 0.21 | $ 0.45 | $ 1.20 |
| Extraordinary charge | $ — | $ — | $ — | $ — | $ (0.01) |
| Net income | $ 0.11 | $ 0.18 | $ 0.21 | $ 0.45 | $ 1.19 |
| **Other financial data and ratios:** | | | | | |
| EBITDA, as adjusted(3) | $ 144,220 | $ 221,658 | $ 283,497 | $ 434,540 | $ 1,017,178 |
| EBITDA, as adjusted, to consolidated interest expense(4) | 2.88x | 3.10x | 2.79x | 3.71x | 7.16x |
| Total debt to EBITDA, as adjusted | 4.49x | 4.31x | 4.29x | 5.21x | 4.67x |
| Ratio of earnings to fixed charges(5) | 1.30x | 1.68x | 1.52x | 1.83x | 2.26x |
| **Balance sheet data:** | | | | | |
| Cash and cash equivalents | $ 95,970 | $ 48,513 | $ 96,532 | $ 349,371 | $ 596,077 |
| Property, plant and equipment, net | 842,850 | 981,615 | 1,372,319 | 3,276,180 | 7,979,160 |
| Investments in power projects | 13,936 | 222,542 | 221,509 | 243,225 | 205,621 |
| Total assets | 1,245,033 | 1,643,192 | 2,032,009 | 4,400,902 | 10,323,203 |
| Short-term debt | 37,492 | 112,966 | 5,450 | 47,470 | 61,558 |
| Long-term debt | 610,400 | 843,268 | 1,211,377 | 2,214,921 | 4,689,562 |
| Total debt | 647,892 | 956,234 | 1,216,827 | 2,262,391 | 4,751,120 |
| Company-obligated mandatorily redeemable convertible preferred securities of subsidiary trusts | — | — | — | 270,713 | 1,122,490 |
| Minority interests | — | — | — | 61,705 | 37,576 |
| Stockholders' equity | 339,061 | 370,658 | 402,710 | 1,100,089 | 2,419,819 |

(The information contained in the Selected Financial Data is derived from the audited Consolidated Financial Statements of Calpine Corporation and Subsidiaries.)

(1) Certain prior years' amounts have been reclassified to conform to the 2000 presentation.

(2) Includes the effect of the assumed conversion of certain trust preferred securities. For the year 2000, the assumed conversion calculation adds 31,746 shares of common stock and $20,841 to the net income results, representing the after tax distribution expense on certain trust preferred securities avoided upon conversion.

(3) This non-GAAP measure is defined as net income less income from unconsolidated investments, plus cash received from unconsolidated investments, plus provision for tax, plus interest expense, plus one-third of operating lease expenses, plus depreciation and amortization, plus distributions on trust preferred securities. EBITDA is presented not as a measure of operating results, but rather as a measure of our ability to service debt. EBITDA should not be construed as an alternative to either (i) income from operations (determined in accordance with generally accepted accounting principles) or (ii) cash flows from operating activities (determined in accordance with generally accepted accounting principles). Prior to 2000, EBITDA had been calculated according to an indenture definition. EBITDA for 1996 through 1999 has been restated to conform to the definition set forth above.

(4) Consolidated interest expense is defined as total interest expense plus one-third of all operating lease obligations and distributions on trust preferred securities.

(5) For purposes of computing our consolidated ratio of earnings to fixed charges, earnings consist of pretax income before adjustment for minority interests in our consolidated subsidiaries or income or loss from equity investees, plus fixed charges, amortization of capitalized interest, and distributed income of equity investees, reduced by interest capitalized and the minority interest in pretax income of subsidiaries that have not incurred fixed charges. Fixed charges consist of interest expensed and capitalized (including amortized premiums, discounts and capitalized expenses related to indebtedness), an estimate of the interest within rental expense and the distributions on our Company-obligated mandatorily redeemable convertible preferred securities of subsidiary trusts.



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**Exhibit IV.**

**Item 7.** ***Management's Discussion and Analysis of Financial Condition and Results of Operations***

*Except for historical financial information contained herein, the matters discussed in this annual report may be considered "forward-looking" statements within the meaning of Section 27A of the Securities Act of 1933, as amended, and Section 21E of the Securities Exchange Act of 1934, as amended, including statements regarding the intent, belief or current expectations of Calpine Corporation ("the Company") and its management. Prospective investors are cautioned that any such forward-looking statements are not guarantees of future performance and involve a number of risks and uncertainties that could materially affect actual results such as, but not limited to, (i) changes in government regulations, including pending changes in California, and anticipated deregulation of the electric energy industry, (ii) commercial operations of new plants that may be delayed or prevented because of various development and construction risks, such as a failure to obtain financing and the necessary permits to operate or the failure of third-party contractors to perform their contractual obligations, (iii) cost estimates are preliminary and actual costs may be higher than estimated, (iv) the assurance that the Company will develop additional plants, (v) a competitor's development of a lower-cost generating gas-fired power plant, (vi) the risks associated with marketing and selling power from power plants in the newly competitive energy market, (vii) the risks associated with marketing and selling combustion turbine parts and components in the competitive combustion turbine parts market, (viii) the risks associated with engineering, designing and manufacturing combustion turbine parts and components, (ix) delivery and performance risks associated with combustion turbine parts and components attributable to production, quality control, suppliers and transportation, (x) the successful exploitation of an oil or gas resource that ultimately depends upon the geology of the resource, the total amount and cost to develop recoverable reserves, and operational factors relating to the extraction of natural gas, or (xi) those risks and uncertainties identified in the Risk Factors section below. Prospective investors are also cautioned that the California energy market remains uncertain. The Company's management is working closely with a number of parties to resolve the current uncertainty. This is an ongoing process and, therefore, the outcome cannot be predicted. It is possible that any such outcome will include changes in government regulations, business and contractual relationships or other factors that could materially affect the Company. However, management believes that a final resolution will not have a material adverse impact on the Company. Prospective investors are also referred to the other risks identified from time to time in the Company's reports and registration statements filed with the Securities and Exchange Commission.*

**Overview**

Calpine is engaged in the development, acquisition, ownership, and operation of power generation facilities and the sale of electricity and steam principally in the United States. At April 19, 2001, we had interests in 49 operating power plants, representing 5,837 megawatts of net capacity.

On January 11, 2000, we announced our plans to expand our presence into the Florida wholesale power market. Our plans are to invest approximately $850 million in power generation facilities and manage these development activities in the Southeast from a new office in Tampa, Florida. We will develop two natural gas-fired energy centers, the 590-megawatt Osprey Energy Center, to be located in the City of Auburndale adjacent to an existing Calpine power facility, and the 1,239-megawatt Blue Heron Energy Center, to be located outside of Vero Beach. Construction for the proposed facilities is planned for 2001 and 2002, respectively, with the Osprey Energy Center to commence commercial operation in the fall of 2003, followed by the Blue Heron Energy Center in mid 2004.

On January 14, 2000, we acquired a 296-megawatt net interest in the Aries Power Plant, a 591-megawatt natural gas-fired plant currently under construction near Pleasant Hill, Missouri, from a subsidiary of Aquila Energy Corporation. Construction started in the fall of 1999 and simple-cycle commercial operation is scheduled to begin in the spring of 2001. The majority of the plant's output will be sold to Missouri Public Service through May 2005. Thereafter, power will be sold into the Southwest Power Pool.

On January 18, 2000, we entered into an agreement to provide the Sacramento Municipal Utility District ("SMUD") with a five-year supply of electricity from our 547 megawatt Sutter Energy Center. The energy



center is currently under construction near Yuba City, California. We will provide 150 megawatts of electricity to SMUD's customer base beginning with the plant's startup in the summer of 2001.

On January 26, 2000, we completed a private offering under Rule 144A of the Securities Act of 1933 of 6,000,000 5 1/2% Remarkable Term Income Deferrable Equity Securities ("trust preferred securities" or "HIGH TIDES") issued by a subsidiary trust at $50.00 each, raising $300.0 million of aggregate gross proceeds. On February 10, 2000, we privately placed an additional 1,200,000 5 1/2% HIGH TIDES pursuant to the exercise of the purchasers' option generating additional gross proceeds of $60.0 million.

On January 28, 2000, we acquired the development rights for the Hermiston Power Project, a 630-megawatt gas-fired cogeneration power facility located near Hermiston, Oregon, from Ida-West Energy Company and TransCanada Pipelines. Construction of the facility commenced in the summer of 2000 and we expect that commercial operation will commence in the summer of 2002.

On February 2, 2000, we announced plans to build, own and operate the Decatur Energy Center, a 794-megawatt gas-fired cogeneration energy center at Solutia Inc.'s Decatur, Alabama chemical facility. Under a 20-year contract, Solutia will lease a portion of the facility to meet its electricity needs and purchase its steam requirements from us. Excess power from the facility will be sold into the Southeastern Wholesale Power Market under a variety of short, medium, and long-term contracts. We will also build a new intrastate natural gas pipeline to fuel the energy center. Construction began in September 2000 and commercial operation is expected to commence in the summer of 2002.

On February 4, 2000, we acquired 100% of the stock of Western Gas Resources California ("Western") from Western Gas Resources, Inc. for $14.9 million. Western's assets include the 130-mile Steelhead natural gas pipeline and the remaining interest in the Sacramento River Gas System natural gas pipeline, now 100% owned by us.

On February 8, 2000, we announced that the Towantic Energy Center received approval through a town-wide referendum to purchase the town-owned land on which the facility will be built. The referendum also approved a Tax Stabilization Agreement that will even out the property taxes paid to the town of Oxford, Connecticut over a 22-year period.

On February 9, 2000, we announced that the California Energy Commission approved plans to construct the Delta Energy Center in Pittsburg, California. The Delta Energy Center, an 874-megawatt gas-fired energy center located at the Dow Chemical facility, is the first facility that will be developed, owned and operated under a joint venture with Bechtel Enterprises, and will provide power to Pittsburg, California and to the greater San Francisco Bay Area. We have a 437-megawatt net interest in this facility.

On February 22, 2000, we announced plans to build, own and operate the Lone Oak Energy Center, a 915-megawatt gas-fired cogeneration facility located in Lowndes County, Mississippi. We anticipate that construction will commence in the spring of 2002 and that commercial operation of the facility will commence in mid 2004.

On February 24, 2000, we announced plans to build, own and operate the Hillabee Energy Center, a 770-megawatt gas-fired cogeneration facility located in Tallapoosa County, Alabama. We anticipate that construction will commence in mid 2001 and that commercial operation of the facility will commence in mid 2003.

On March 6, 2000, we announced that we entered into a partnership agreement with Cleco Midstream Resources, an affiliate of Pineville,

Louisiana-based Cleco Corporation, to participate in the Acadia Energy Center. The partners plan to build, own and operate the 1,239-megawatt natural gas-fired energy center near Eunice, Louisiana. We have a 620-megawatt net interest in this facility. Construction commenced in mid 2000 and commercial operation for the energy center is expected in May 2002.

On March 23, 2000, we announced plans to build, own and operate the Wawayanda Energy Center, a 630-megawatt natural gas-fired facility to be located near Middletown, New York. We anticipate that construction will begin in late 2002 and commercial operation will begin in late 2004.



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On March 30, 2000, we purchased a 78.5%, or 394-megawatt, interest in the 502-megawatt Hidalgo Energy Center, located in Edinburg, Texas, from Duke Energy North America for $235 million. The purchase included a cash payment of $134 million and the assumption of a $101 million capital lease obligation. The facility began commercial operation on June 14, 2000. The Hidalgo Energy Center sells power under our system approach into the Electric Reliability Council of Texas' wholesale market and potentially may sell into northern Mexico in the future.

On March 30, 2000, we announced a 50-megawatt expansion of the natural gas-fired, cogeneration power plant located in Morris, Illinois. We also announced the signing of a power sales agreement to deliver approximately 100 megawatts of capacity from the Morris Power Plant to Commonwealth Edison Company through the end of 2000. The majority of the electricity and all of the steam produced by the plant are sold to Equistar Chemicals, L.P. under a long-term agreement that expires in 2023.

On April 20, 2000, we announced plans to construct the Calgary Energy Centre. Scheduled to begin commercial operation in late 2002, the 300-megawatt combined-cycle, natural gas-fired facility was the first independent power project announced in the Calgary area, and represents our first investment in the Canadian power industry.

On May 16, 2000, we announced the establishment of a new business unit, Calpine c*Power, to serve the rapidly growing worldwide demand for highly reliable critical power. Highly reliable power adds to our growing line of high-value energy products, which includes green power, ancillary services and peaking power.

On May 22, 2000, we announced plans to purchase 36 F-class turbines from Orlando, Florida-based Siemens Westinghouse Power Corporation. The agreement includes long-term service programs and performance enhancements on existing equipment. In 2003 and 2004, Siemens Westinghouse will be obligated to deliver a total of 36 turbines to us. When operated in a combined-cycle configuration, the 36 new turbines equate to approximately 9,800 additional megawatts of electricity generation potential.

On May 23, 2000, we announced the acquisition of development rights to build, own and operate the 700-megawatt natural gas-fired Fremont Energy Center near Fremont, Ohio. Construction is scheduled to begin in mid 2001 and we expect commercial operation to commence in the summer of 2003.

On May 23, 2000, we entered into an amended and restated $400 million, three-year revolving line of credit led by The Bank of Nova Scotia, replacing an expiring $100 million credit facility. The amended and restated facility will be used for working capital and other general corporate purposes.

On May 31, 2000, we acquired the remaining 50% interest in the 105-megawatt Kennedy International Airport Power Plant ("KIAC") in Queens, New York, and the 40-megawatt Stony Brook Power Plant located at the State University of New York at Stony Brook on Long Island from Statoil Energy, Inc. We paid approximately $71 million in cash and assumed a capital lease obligation relating to the Stony Brook Power Plant. We initially acquired a 50% interest in both facilities in December 1997.

On June 8, 2000, we effected a two-for-one split of our common stock for stockholders of record as of May 29, 2000.

On June 15, 2000, we announced that we acquired the Freestone Energy Center from New Orleans, Louisiana-based Entergy Corp. Freestone is a 1,052-megawatt natural gas-fired energy center located in Freestone County, Texas, near Fairfield, about 80 miles southeast of Dallas. The technologically advanced energy center is currently under construction, with a two-phased commercial start-up beginning in mid 2002. We paid approximately $61.0 million in cash and assumed certain liabilities. This represented payment for the land and development rights for the Freestone Energy Center, previous progress payments made for four General Electric gas turbines, two steam turbines and related equipment, and development expenditures incurred to date.

On June 27, 2000, we announced plans to build, own and operate a natural gas-fired cogeneration energy center at the BP Amoco chemical facility in Decatur, Alabama. The Morgan Energy Center will generate approximately 790 megawatts of electricity in addition to supplying steam for BP Amoco's facility.

Construction began in September 2000 and we expect commercial operation to commence in September 2002.

On June 29, 2000, we announced that we secured the rights to develop, build, own and operate the Teayawa Energy Center, a 608-megawatt natural gas-fired power generating facility near the town of Thermal in Riverside County, California through a development agreement with Adair International Oil and Gas, Inc. The Teayawa Energy Center will be sited on the Torres Martinez Desert Cahuilla Indians' land through a long-term lease agreement with the Torres Martinez. Commercial operation is expected in early 2004.

On June 30, 2000, we completed the acquisition from Edison Mission Energy of the remaining 50% ownership interest in a 153-megawatt natural gas-fired, combined-cycle cogeneration facility located in Auburndale, Fla. We paid approximately $22.0 million in cash and assumed certain liabilities, including project level debt. Related to the project level debt was the assumption of an interest rate swap agreement with a notional amount of $121.5 million at December 31, 2000, which effectively converts the project level debt's floating rate to a fixed rate of 6.52% per annum. We acquired an initial 50% ownership interest in the Auburndale Power Plant in October 1997.

On July 5, 2000, we completed three acquisitions of natural gas reserves for $206.5 million, including the acquisition of Calgary-based Quintana Minerals Canada Corp. ("QMCC"), three fields in the Gulf of Mexico and natural gas assets in the Piceance Basin, Colorado and onshore Gulf Coast. These acquisitions increased our proven reserves to 430 bcfe, which at full production, can fuel 800 to 900 megawatts of combined-cycle gas-fired power generation.

On July 6, 2000, we announced the addition of 115 megawatts of peaking capacity to the natural gas-fired, cogeneration facility located in Auburndale, Florida.

On July 18, 2000, we announced plans to purchase from GE Power Systems 21 model 7FB turbines which will produce an additional 5,250 megawatts of electricity when operated in combined-cycle mode. We will take delivery of 12 turbines in 2003, with the remainder of the contract to be filled in 2004.

On July 19, 2000, we announced we will develop, construct and own a natural gas-fired, combined-cycle power generation facility in Haywood County, Tennessee. The proposed Haywood Energy Center represents our fourth project that will interconnect with the Tennessee Valley Authority. The 915-megawatt facility is scheduled to begin commercial operation in late 2003.

On July 20, 2000, we acquired the Oneta Energy Center from Panda Energy, International, Inc. Oneta is a 1,138-megawatt natural gas-fired energy center under construction in Coweta, Oklahoma, southeast of Tulsa. Under our agreement with Panda, we may be obligated to make certain contingent payments during the operation of the Oneta facility. We also acquired from Panda 24 General Electric 7FA gas turbines and 12 steam turbines, of which 16 gas turbines and 8 steam turbines were subsequently repurchased by another party in partnership with Panda.

On July 21, 2000, we signed a memorandum of understanding to purchase 85 heat recovery steam generators ("HRSGs") from St. Louis, Missouri-based Nooter/ Eriksen. We will begin taking delivery of the HRSG in 2001, with the bulk of the contract to be filled through 2004.

On July 24, 2000, we announced plans to enter into a $2.5 billion revolving construction credit facility, through our wholly owned subsidiary Calpine Construction Finance Company II, LLC ("CCFC II"), with a consortium of banks, including The Bank of Nova Scotia and Credit Suisse First Boston as lead arrangers. We signed this agreement during the fourth quarter of 2000.

On August 1 and 2, 2000, we announced the completion of consent solicitations to effect certain amendments to six Indentures governing certain outstanding Calpine public debt securities which are due in the years 2004 through 2009. Supplemental Indentures effecting such amendments were executed by Calpine and the respective Trustees.

On August 9, 2000, we completed a public offering of 23,000,000 shares of our common stock at $34.75 per share. The gross proceeds were $799.3 million.



On August 9, 2000, we, through our wholly owned subsidiary, Calpine Capital Trust III, completed a private offering, under Rule 144A of the Securities Act of 1933, of 10,350,000 5% HIGH TIDES at a price of $50.00 per share. The gross proceeds from the offering were $517.5 million.

On August 10, 2000, we completed a public offering of $250.0 million of our 8 1/4% Senior Notes due 2005 and $750.0 million of our 8 5/8% Senior Notes due 2010. The 8 1/4% Senior Notes mature on August 15, 2005 and interest is payable semi-annually. The 8 5/8% Senior Notes mature on August 15, 2010 and interest is payable semi-annually.

On August 16, 2000, we acquired the remaining 80% interest in the Agnews Power Plant, a 29-megawatt natural gas-fired, combined-cycle

facility located in San Jose, California from GATX Capital Corporation for a total purchase price of $4.9 million. We first acquired a 20% equity interest in the Agnews Power Plant in 1990.

On August 31, 2000, we announced that we acquired the remaining 45% equity interest in the Aidlin Power Plant from an affiliate of Sumitomo Corporation for a total purchase price of $6.4 million. We initially acquired a 5% equity interest in the Aidlin Power Plant in 1989, representing our first megawatt of generation. That interest was increased to 55% with the acquisition of two other partners' interests in 1999. Located in an area of Lake and Sonoma Counties in northern California ("The Geysers"), Aidlin is a 20-megawatt power plant.

On September 1, 2000, we completed a leveraged lease financing transaction to provide the term financing for both Phase I and Phase II of the Pasadena, Texas cogeneration project. Under the terms of the lease, we received $400.0 million in gross proceeds and recorded a deferred gain of approximately $65.0 million.

On September 21, 2000, we announced a five-year power sales agreement with Imperial Irrigation District ("IID"). Beginning May 2002, we will deliver 150 megawatts of electricity from our new 555-megawatt South Point Energy Center to IID's southern California electric customers.

On October 12, 2000, we completed the acquisition of Northbrook, Illinois-based SkyGen Energy LLC ("SkyGen") from Michael Polsky and Wisvest Corporation ("Wisvest"), an affiliate of Wisconsin Energy Corp. The total purchase price of $359.1 million included $294.2 million in cash and 2,117,742 shares of our common stock (which were valued in the aggregate at $64.9 million at the signing of the Letter of Intent). Additionally, we agreed to the assumption of certain recourse and non-recourse obligations of SkyGen, the assumption of certain contingent obligations of Wisvest and Wisconsin Energy Crop. on behalf of SkyGen, and the obligation to make certain additional contingent payments for completion of certain project development milestones. Under the terms of the agreement, we acquired three operating facilities, five facilities under construction, 12 late-stage development projects and 16 project-stage development projects. In addition, we assumed purchase rights and progress payments for 34 General Electric 7FA gas turbines to power these projects.

On October 16, 2000, we jointly announced with EOG Resources, Inc. ("EOG") the signing of a one-year marketing agreement that links the daily price of natural gas to the price of electricity. EOG agreed to sell 10 million cubic feet of natural gas per day directly to us. The transaction became effective January 1, 2001 and will terminate December 31, 2001.

On October 17, 2000, we announced plans to enter into a 400-megawatt long-term power supply agreement with Pacific Gas & Electric Company ("PG&E") that will provide competitively priced electricity for PG&E's northern California customers. Electricity deliveries will begin July 1, 2001 and end December 31, 2003.

On October 17, 2000, we announced that we presented plans, with Tampa, Florida-based Seminole Electric Cooperative, Inc. ("Seminole"), to the Florida Public Service Commission under which our proposed Osprey Energy Center will supply electric power under contract to help meet Seminole's member systems' power needs.



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On October 20, 2000, we jointly announced with Cleco Corporation, a regional energy services company headquartered in Pineville, Louisiana, the signing of a 20-year contract with Aquila Energy, a wholly owned subsidiary of UtiliCorp United, for 580 megawatts of the output of the jointly owned Acadia Energy Center currently under construction in Acadia Parish, Louisiana. We have a 50% interest in Acadia Power Partners LLC, which owns the 1,239-megawatt combined-cycle plant currently under construction. The remaining 50% interest is held by Cleco Midstream Resources LLC, a wholly owned subsidiary of Cleco. Under terms of a tolling agreement, starting July 1, 2002, Aquila Energy will supply the natural gas needed to generate 580 megawatts of electricity and will own and market the produced power.

On October 23, 2000, we announced that we entered into a project development agreement to build, own and operate a 1,100-megawatt natural gas-fired energy center to be located on the Ohio River in Hamilton Township, Lawrence County, Ohio. The proposed Lawrence Energy Center will represent a $510 million investment, with a target commercial operation date of May 2004.

On October 31, 2000, we announced that we entered into a long-term, natural gas transportation and storage agreement with Kinder Morgan Texas Pipeline, Inc. ("KMTP"), a subsidiary of Kinder Morgan, Inc. We will have access to up to 375,000 MMBtu of firm natural gas transportation service per day from KMTP for a period of 10 years. The agreement began on January 1, 2001.

On October 31, 2000, we announced with Aquila Energy, a wholly owned subsidiary of UtiliCorp United, the completion of a $270 million construction and leverage lease financing of the Aries Power Plant, a 591-megawatt gas-fired power plant under construction in Pleasant Hill, Missouri. The majority of the plant's capacity and electrical output has already been sold under a four-year contract (June 2001 — May 2005) to Missouri Public Service, a division of UtiliCorp. Under the terms of separate tolling contracts, we, together with Aquila, will purchase the balance of the plant's capacity and output, remarketing it into the Southwest Power Pool and Southeast Electric Reliability Counsel regional power markets. The marketing and fuel supply responsibilities will be handled by Aquila.

On November 14, 2000, we effected a two-for-one split of our common stock for stockholders of record as of November 6, 2000.

On November 15, 2000, we announced that our wholly owned subsidiary, SkyGen, entered into an agreement to supply CP&L Energy ("CP&L") additional power produced from the Broad River Energy Center Expansion. This expansion, the second phase of construction of the Broad River Energy Center, involves the installation of two additional combustion turbines capable of producing an additional 360 megawatts of peaking power. Construction is expected to be completed in the summer of 2001. The output will be sold to CP&L under long-term power purchase agreements.

On November 15, 2000, we acquired TriGas Exploration, Inc. ("TriGas"), a Calgary-based oil and gas company, for a total purchase price of $101.1 million. The purchase price included cash payments of $79.6 million, as well as assumed net indebtedness of $21.5 million. The acquisition provides us with natural gas reserves to fuel our proposed Calgary Energy Centre, and a 26.6% working interest in the East Crossfield Gas Plant, extensive pipelines and gathering systems and a significant undeveloped land base with development potential.

On December 12, 2000, we announced that we are considering plans to develop and operate a new energy-efficient electricity-generating facility in an effort to meet a portion of the fast-growing local and regional electricity needs in northern California. We are preparing technical studies for the proposed 1,065-megawatt facility. The proposed East Altamont Energy Center will be located in the northeastern corner of Alameda County, and situated in an area dominated by major regional high voltage transmission lines, a natural gas compressor station, wind power generators, and the substantial pumping stations associated with the California Aqueduct and the Delta-Mendota Canal. Upon completion of licensing through the California Energy Commission, construction would begin in June 2002, with commercial operation beginning in June 2004.

On December 13, 2000, we acquired Boca Raton, Florida-based Power Systems Mfg. LLC ("PSM"), an industry leader in combustion turbine component engineering, design and manufacturing, for a total purchase



price of $16.3 million. The purchase price included cash payments of $5.6 million and 281,189 shares of Calpine common stock (which were valued at $10.7 million at the closing of the agreement). Additionally, the agreement provides for five equal installments of cash payments totaling $26.7 million, beginning in January 2002, contingent upon future PSM performance. PSM will operate as a subsidiary of Calpine and will continue to sell its products to the combustion turbine market.

On December 15, 2000, we acquired strategic power assets from Dartmouth, Massachusetts-based Energy Management, Inc. ("EMI") for a total purchase price of $145.0 million and the assumption of project financings. The purchase price included cash payments of $100.0 million and 1,102,601 shares of Calpine common stock (which were valued in the aggregate at $45.0 million at the closing of the agreement). Under the terms of the agreement, we acquired the remaining interest in three recently constructed combined-cycle power generating facilities located in Dighton, Massachusetts, Tiverton, Rhode Island, and Rumford, Maine, as well as Calpine-EMI Marketing LLC, a joint marketing venture between Calpine and EMI.

On December 18, 2000, we announced with PG&E Corporation an agreement under which we will acquire the Otay Mesa Generating Project in San Diego County. In accordance with the terms of the agreement, we will build, own and operate the 618-megawatt generating facility, and PG&E Corporation's National Energy Group will contract for up to 250 megawatts of the project's output. Construction is expected to begin in the summer of 2001.

On December 19, 2000, we completed leveraged lease transactions in which we sold the Tiverton, Rhode Island and Rumford, Maine facilities (purchased from EMI) to a single owner lessor for $466.7 million, which then leased the facilities back to our Tiverton and Rumford subsidiaries. We have fully and unconditionally guaranteed all of the obligations of the Tiverton and Rumford subsidiaries under the leases and other lease documents related to their lease of the facilities from the owner lessor. The owner lessor paid the purchase price for the facilities through an equity investment and by issuing notes. The notes were purchased by a pass through trust created by the Tiverton and Rumford subsidiaries. The purchase of the notes was financed by the private placement under Rule 144A of the Securities Act of 1933 by the pass through trust of $366.0 million in 9.0% pass through certificates due July 15, 2018.

On December 22, 2000, we completed a leveraged lease financing transaction of our West Ford Flat and Bear Canyon projects. Under the terms of the agreement, the facilities were incorporated into Calpine's geothermal lease facility, which we originally entered into on May 7, 1999. We received $81.0 million in gross proceeds and recorded a deferred loss of approximately $8.1 million, which is being amortized as an increase of operating lease expense over the remaining life of the lease.

**Transactions Announced or Consummated Subsequent to December 31, 2000, and Recent Developments**

On January 11, 2001, we jointly announced with Western Hub Properties LLC ("WHP") that WHP's wholly owned subsidiary, Lodi Gas Storage, LLC, entered into a long-term firm agreement to supply Calpine with storage services at WHP's Lodi Gas Storage facility near Lodi, California. The storage arrangement can provide up to 4 billion cubic feet (bcf) of working gas inventory and daily deliverability equal to approximately 20 percent of our western region peak day gas requirements in 2002. The Lodi Gas Storage Project, located approximately 50 miles east of San Francisco, began construction in early April of 2001.

On January 17, 2001, our wholly owned subsidiary, SkyGen, announced plans to build, own and operate an 850-megawatt natural gas-fired cogeneration facility in Augusta, Georgia. The proposed Augusta Energy Center will be fueled by clean natural gas and will supply energy to DSM Chemicals North America, Inc. for use in its production processes. Construction is expected to begin in the third quarter of 2001.

On January 26, 2001, we announced the acquisition of the development rights from Cogentrix, an independent power company based in North Carolina, for the 565-megawatt Washington Parish Energy Center, located near Bogalusa, Louisiana. We are managing construction of the facility, which began in January 2001.

On February 12, 2001, we announced that the Florida Public Service Commission approved a joint application filed by Calpine and Seminole Electric Cooperative, Inc., under which we will build a 590-mega-



watt combined-cycle power generating facility, the Osprey Energy Center, to supply electric power to help meet Seminole's members' power needs.

On February 13, 2001, we announced that our wholly owned subsidiary, SkyGen, entered into an agreement to supply Alliant Energy's Wisconsin Power & Light Co. ("WP&L") 453 megawatts of electric capacity and energy from the proposed 600-megawatt Riverside Energy Center, which will be located next to WP&L's existing power plant near Beloit, Wisconsin. The power sales agreement is for a term of ten years. Construction of the Riverside Energy Center is expected to begin during the fourth quarter of 2001, with commercial operation scheduled for mid 2003.

On February 15, 2001, we completed a public offering of $1.15 billion of our 8 1/2% Senior Notes due 2011. The Senior Notes due 2011 bear interest at 8 1/2% per year, payable semi-annually, and mature on February 15, 2011.

On March 16, 2001, we announced that our wholly owned subsidiary, SkyGen, entered into a 10-year agreement to supply Xcel Energy, formerly Public Service Co. of Colorado, with 336 megawatts of peaking capacity. Power will be delivered from the proposed Colorado Energy Center, a $100 million electricity generating facility to be located east of Denver in the City of Aurora. Construction of the Colorado Energy Center is expected to begin in early 2002, with commercial operation scheduled for 2003.

On March 22, 2001, we announced plans to build, own and operate a 600-megawatt electricity generating facility to be located near the town of Hudson in Weld County, Colorado. The proposed Rocky Mountain Energy Center will supply Xcel Energy, formerly Public Service Co. of Colorado, with up to 600 megawatts of electricity for a period of ten years. Construction of the $360 million facility is expected to begin in 2002 with commercial operation scheduled for mid 2004.

On March 27, 2001, we announced plans to build, own and operate a 1,000-megawatt natural gas-fired power facility in Deer Park, Texas. The proposed Deer Park Energy Center will supply steam to Shell Chemical Company and electric power to the wholesale market. Construction for the Deer Park Energy Center is expected to begin in mid 2001, with the first phase of the project operational by early 2003 and the second, larger phase operational by mid 2004.

On April 3, 2001, we announced that our affiliate, Calpine Power America, L.P., was certified as a Retail Energy Provider in the Electric Reliability Council of Texas ("ERCOT"). This allows us to offer services to a full range of wholesale and retail customers in Texas. Calpine Power America will sell to large industrials, in addition to municipalities, cooperatives, and investor-owned utilities. Additionally, we received an ERCOT certification to be a Qualified Scheduling Entity ("QSE"). As a QSE, Calpine Power Management, L.P. may act on behalf of generators and consumers in the region and would be responsible for scheduling the generation of energy flowing to the electricity grid with the ERCOT Independent System Operator.

On April 3, 2001, we acquired all of the common shares of WRMS Engineering, Inc. ("WRMS"), a California-based engineering and architectural firm, through a stock-for-stock exchange in which WRMS shareholders received a total of 151,176 shares of Calpine common stock. The aggregate value of the transaction is approximately $7.8 million, including the assumed indebtedness of WRMS. WRMS is expected to provide services to support our c*Power unit, which provides highly reliable, critical power to industrial and high tech customers.

On April 11, 2001, we acquired the development rights from Enron North America for the 750-megawatt natural gas-fired Pastoria Energy Center planned for Kern County, California. The $500 million project was licensed by the California Energy Commission in December 2000. Construction is expected to begin during the summer of 2001 with commercial operation scheduled for the summer of 2003.

On April 17, 2001, we acquired the development rights from Kirkland, Washington-based National Energy Systems Company for the 248-megawatt natural gas-fired Goldendale Energy Center planned for Goldendale, Washington. Energy generated from the Goldendale facility will be sold directly into the Northwest Power Pool. Construction commenced in the spring of 2001, and energy deliveries are scheduled to begin in the summer of 2002.

On April 19, 2001, we announced the purchase of 35 model 7FB and 11 model 7FA gas-fired turbines from GE Power Systems. We will take delivery of 5 turbines in 2002, with the remainder of the contract to be filled by the end of 2005. With this purchase, we have firm orders in place for the delivery of 203 turbines, which, when operated in a combined-cycle configuration, will produce approximately 50,000 megawatts of baseload capacity.

On April 19, 2001, we completed our merger with Encal Energy Ltd. ("Encal"), a Calgary, Alberta-based natural gas and petroleum exploration and development company. Encal shareholders received, in exchange for each share of Encal common stock, 0.1493 shares of Calpine common equivalent shares (called "exchangeable shares") of our subsidiary, Calpine Canada Holdings Ltd. A total of 16,603,633 exchangeable shares were issued to Encal shareholders in exchange for all of the outstanding shares of Encal common stock. Each exchangeable share is exchangeable for one share of Calpine common stock. The aggregate value of the transaction was approximately US $1.1 billion, including the assumed indebtedness of Encal. This transaction was accounted for as a pooling-of-interests. With the addition of Encal's assets, which currently produce approximately 230 million cubic feet of gas equivalent ("mmcfe") per day, net of royalties, our net production is expected to increase to 390 mmcfe per day in North America, enough to fuel approximately 2,300 megawatts of our power fleet.

*Recent Developments in the California Power Market.* The deregulation of the California power market has produced significant unanticipated results in the past year. The deregulation froze the rates that utilities can charge their retail customers in California and prohibited the utilities from buying power on a forward basis, while wholesale power prices were not subjected to limits.

In the past year, a series of factors have reduced the supply of power to California, which has resulted in wholesale power prices that have been significantly higher than historical levels. Several factors contributed to this increase. These included:

- significantly increased volatility in prices and supplies of natural gas;
- an unusually dry fall and winter in the Pacific Northwest, which reduced the amount of available hydroelectric power from that region (typically, California imports a portion of its power from this source);
- the large number of power generating facilities in California nearing the end of their useful lives, resulting in increased downtime (either for repairs or because they have exhausted their air pollution credits and replacement credits have become too costly to acquire on the secondary market); and
- continued obstacles to new power plant construction in California, which deprived the market of new power sources that could have, in part, ameliorated the adverse effects of the foregoing factors.

As a result of this situation, two major California utilities that are subject to the retail rate freeze, including PG&E, have faced wholesale prices that far exceed the retail prices they are permitted to charge. This has led to significant underrecovery of costs by these utilities. As a consequence, these utilities have defaulted under a variety of contractual obligations, including payment obligations to power generators. PG&E has defaulted on payment obligations to us under our long-term QF contracts which are subject to federal regulation under the Public Utility Regulatory Policies Act of 1978, as amended ("PURPA"). The PG&E QF contracts are in place at eleven of our facilities and represent nearly 600 megawatts of electricity for northern California customers (See Notes 15 and 20 of the Notes to Consolidated Financial Statements).

We have continued to honor our contractual obligations to PG&E under our QF contracts. To date, we have refrained from pursuing our collection remedies with respect to PG&E's default, however, we have been actively involved with the California utilities, the California legislature, and other interested parties to develop legislation designed to stabilize energy prices through the application of a long-term energy pricing methodology (for a five-year period) in place of the short-term pricing methodology currently utilized under the QF contracts, as discussed above. We also expect further legislation to enable the California utilities to finance over a longer term the difference between the wholesale prices that have been paid and the retail prices they received during last fall and into this winter. We believe that this should enhance PG&E's ability to make



payment of all past due amounts. However, management cannot predict the timing or ultimate outcome of the legislative process or the payment of amounts due under our contracts.

As this situation has deteriorated, California has taken steps to restore a predictable and reliable power market to the State. Recently, California adopted legislation permitting it to issue long-term revenue bonds to provide funding for wholesale purchases of power. The bonds will be repaid with the proceeds of payments by retail customers over time. The California Department of Water Resources ("DWR") sought

bids for long-term power supply contracts. We successfully bid in that auction, and announced, as indicated below, that we have signed three significant long-term power supply contracts with DWR.

On February 7, 2001, we announced the signing of a 10-year, $4.6 billion fixed-price contract with DWR to provide electricity to the State of California. We committed to sell up to 1,000 megawatts of electricity, with initial deliveries of 200 megawatts starting October 1, 2001, and increasing to 1,000 megawatts by January 1, 2004. This contract will continue through 2011. The electricity will be sold directly to DWR on a 24-hour, 7-day-a-week basis.

On February 28, 2001, we announced the signing of two long-term power sales contracts with DWR. Under the terms of the first contract, a $5.2 billion, 10-year, fixed-price contract, we commit to sell up to 1,000 megawatts of generation. Initial deliveries are scheduled to begin July 1, 2001 with 200 megawatts and increase to 1,000 megawatts by as early as July 2002. Under the terms of the second contract, a 20-year contract totaling up to $3.1 billion, we will supply DWR with up to 495 megawatts of peaking generation, beginning with 90 megawatts as early as August 2001, and increasing up to 495 megawatts as early as August 2002.

On March 13, 2001, we announced the signing of a two-month deal to provide 555 megawatts of electricity to DWR from our new South Point Energy Center during plant testing, effective immediately through May 15, 2001.

*PG&E Bankruptcy Proceedings.* On April 6, 2001, PG&E filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code. As of April 6, 2001, we had recorded approximately $266 million in accounts receivable with PG&E under our QF contracts, plus a $69 million note receivable not yet due and payable. We are currently selling power to PG&E pursuant to our long-term QF contracts, and PG&E is paying on a current basis for these purchases since its bankruptcy filing. We are confident that PG&E, through a successful reorganization, will be able to pay us for all past due power sales, in addition to electricity deliveries made on a going-forward basis. (For additional information, including information on certain receivables, see Notes 15 and 19 to the Consolidated Financial Statements.

*CPUC Proceedings Regarding QF Contract Pricing.* Our QF contracts with PG&E provide that the California Public Utilities Commission ("CPUC") has the authority to determine the appropriate utility "avoided cost" to be used to set energy payments for certain QF contracts, including those for all of our QF plants in California which sell power to PG&E. Section 390 of the California Public Utility Code provides QFs the option to elect to receive energy payments based on the California Power Exchange("PX") market clearing price. In mid 2000, our QF facilities elected this option and were paid based upon the PX zonal day-ahead clearing price ("PX Price") from summer 2000 until January 19, 2001, when the PX ceased operating a day-ahead market. Since that time, the CPUC has ordered that the price to be paid for energy deliveries by QFs electing the PX Price shall be based on a natural gas cost-based "transition formula." The CPUC has conducted proceedings (R. 99-11-022) to determine whether the PX Price was the appropriate price for the energy component upon which to base payments to QFs which had elected the PX based pricing option. The CPUC has issued a proposed decision to the effect that the PX Price was the appropriate price for energy payments under the California Public Utility Code. However, a final decision has not been issued to date. Therefore, it is possible that the CPUC could order a payment adjustment based on a different energy price determination. We believe that the PX Price was the appropriate price for energy payments but there can be no assurance that this will be the outcome of the CPUC proceedings.

On March 28, 2001, the CPUC issued an order (Decision 01-03-067) (the "March 2001 Decision") proposing to change, on a prospective basis, the composition of the short run avoided cost ("SRAC") energy



price formula, which is reset monthly, used by the California utilities in QF contracts. Prior to the March 2001 Decision, CPUC regulations calculated SRAC based on 50% Topock and 50% Malin border gas indices. In the March 2001 Decision, the CPUC changed this formulation to eliminate the prices at Topock from the SRAC formula. The March 2001 Decision is subject to challenges at the CPUC and the Federal Energy Regulatory Commission ("FERC").

*FERC Investigation into California Wholesale Markets.* In response to the increase in wholesale energy prices in the California markets, on June 28, 2000, the Board of Governors of the California Independent System Operator (the "ISO"), which controls the long-distance high-voltage power lines that deliver electricity throughout California and adjoining states, reduced the price cap applicable to the ISO's wholesale energy and ancillary services markets from $750/MWh to $500/MWh. The ISO subsequently reduced the price cap to $250/MWh effective August 7, 2000. During this period, however, the PX maintained a separate price cap set at a much higher level applicable to the day-ahead and day-of markets administered by the PX. On August 23, 2000, the FERC denied a complaint filed August 2, 2000 by San Diego Gas & Electric Company ("SDG&E") that sought to extend the ISO's $250/MWh price cap to all California energy and ancillary service markets, not just the markets administered by the ISO. However, in its order denying the relief sought by SDG&E, FERC instructed its staff to initiate an investigation of the California power markets and to report its findings to the FERC and held further hearing procedures in abeyance pending the outcome of this investigation. Under FERC regulations, QF contracts are exempt from regulation under the Federal Power Act, which is the legislation that provides the authority for FERC to investigate the California power markets and frame equitable relief with respect to the California wholesale markets. Therefore, any such relief will only apply to sales by Calpine in the short-term market. None of Calpine's receivables related to power produced under its long-term QF contracts with PG&E should be affected by any FERC findings pursuant to the proceedings described below. See "Item 1 — Business — Government Regulation — Federal Energy Regulation — Federal Power Act Regulation."

On November 1, 2000, FERC released a Staff Report detailing the results of the Staff investigation, together with an "Order Proposing Remedies for California Wholesale Markets" (the "November 1 Order"). In the November 1 Order, FERC found that the California power market structure and market rules were seriously flawed, and that these flaws, together with short supply relative to demand, resulted in unusually high energy prices. The November 1 Order proposed specific remedies to the identified market flaws, including: (a) imposition of a so-called "soft" price cap at $150/MWh to be applied to both the PX and ISO markets, which would allow bids above $150/MWh to be accepted, but would subject such bids to certain reporting obligations requiring sellers to provide cost data and/or identify applicable opportunity costs and specifying that such bids may not set the overall market clearing price; (b) elimination of the requirement that the California utilities sell into and buy from the PX; (c) establishment of independent non-stakeholder governing boards for the ISO and the PX; and (d) establishment of penalty charges for scheduling deviations outside of a prescribed range. In the November 1 Order, FERC established October 2, 2000, the date 60 days after the filing of the SDG&E complaint, as the "refund effective date." Under the November 1 Order, rates charged for service after that date through December 31, 2002 will remain subject to refund if determined by FERC not to be just and reasonable. While FERC concluded that the Federal Power Act and prior court decisions interpreting that act strongly suggested that refunds would not be permissible for charges in the period prior to October 2, 2000, it noted that it was willing to explore proposals for equitable relief with respect to charges made in that period.

On December 15, 2000, FERC issued a subsequent order that affirmed in large measure the November 1 Order (the "December 15 Order"). Various parties have filed requests for administrative rehearing and for judicial review of aspects of FERC's December 15 Order. The outcome of these proceedings, and the extent to which FERC or a reviewing court may revise aspects of the December 15 Order or the extent to which these proceedings may result in a refund of or reduction in the amounts charged by the our subsidiaries for power sold in the ISO and PX markets, cannot be determined at this time.



**Selected Operating Information**

Set forth below is certain selected operating information for our power plants and steam fields, for which results are consolidated in our statements of operations. Results vary for the twelve months ended December 31, 2000, as compared to the same period in 1999 and 1998, primarily due to the consolidation of acquisitions, favorable energy pricing, and increased production. Electricity revenue is composed of fixed capacity payments, which are not related to production, and variable energy payments, which are related to production. Capacity revenues include, besides traditional capacity payments, other revenues such as Reliability Must Run and Ancillary Service revenues. The information set forth under thermal and other revenue consists of the results for the Thermal Power Company Steam Fields prior to the acquisition of the PG&E power plants on May 7, 1999, in addition to host thermal sales and other revenue. As a result of this acquisition, steam output is used to produce electricity, whereas this output was previously sold to third parties.

| | Years Ended December 31, | | | | |
|---|---|---|---|---|---|
| | 1996 | 1997 | 1998 | 1999 | 2000 |
| | (dollars in thousands, except production and pricing data) | | | | |
| **Power Plants:** | | | | | |
| Electricity and steam revenues: | | | | | |
| Energy (1) | $ 97,997 | $ 116,577 | $ 334,883 | $ 461,069 | $ 1,232,550 |
| Capacity | $ 63,549 | $ 75,588 | $ 123,380 | $ 247,620 | $ 382,478 |
| Thermal and other | $ 37,918 | $ 45,112 | $ 49,968 | $ 54,112 | $ 99,297 |
| Megawatt hours produced | 1,985,404 | 2,158,008 | 9,864,080 | 14,802,709 | 22,749,588 |
| Average energy price per megawatt hour | $ 49.36 | $ 54.02 | $ 33.95 | $ 31.15 | $ 54.18 |

(1) Includes spread on sales of purchased power.

**Results of Operations**

***Year Ended December 31, 2000 Compared to Year Ended December 31, 1999***

*Revenue* — Total revenue increased 159% to $2,547.1 million in 2000 compared to $983.5 million in 1999, primarily due to increased hedging, balanced and related activity by CES and to the impact of recognition of a full year's income from various assets that were acquired in 1999, recognition of a partial year's income from various assets that were acquired in 2000, increased production, and favorable pricing.

*Electric generation and marketing revenue* increased 165% to $2,073.0 million in 2000 compared to $783.5 million in 1999. Approximately $269.4 million of the increase was generated by a full year's activity of our geothermal facilities, which we initially acquired in May 1999. The facilities that we acquired as part of the

Cogeneration Corporation of America, Inc. acquisition in December 1999, which was later renamed Calpine Cogeneration Corporation ("CCC"), contributed $107.2 million in 2000. Additionally, commencement of commercial operations at our Hidalgo facility and of our Pasadena expansion generated approximately $147.1 million. During 2000, our acquisitions of KIAC, Stony Brook, Auburndale, and Agnews contributed an additional $113.5 million to the overall increase in revenue. The balance was primarily due to increased production and favorable energy pricing in various markets, particularly California. Sales of purchased power increased $347.3 million due to increased Calpine Energy Services, LP ("CES") hedging, balancing and related activity.

*Oil and gas production and marketing revenue* increased 185% to $444.5 million in 2000 compared to $156.0 million in 1999. Approximately $194.6 million of the increase was due to increased production and favorable pricing, in addition to the acquisition of Sheridan Energy, Inc. in October 1999 and several strategic gas acquisitions during 2000, including Quintana Minerals Canada Corp. and TriGas Exploration Inc. The remainder of the variance was caused by the increased CES hedging, balancing and related activity.



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*Income from unconsolidated investments in power projects* decreased 33% to $24.6 million in 2000 compared to $36.6 million in 1999. Approximately $5.2 million of the decrease is primarily attributable to the consolidation of KIAC, Stony Brook, Auburndale, and Agnews' results in electricity and steam sales as a result of our purchase of these facilities during 2000. We also recorded $8.8 million less equity income from Sumas, and $1.2 million less equity income from our investment in Bayonne. These amounts were partially offset by $4.7 million of revenue that we recorded in connection with our investment in the Grays Ferry facility that we acquired in December 1999.

*Cost of revenue* — Cost of revenue increased to $1,700.1 million in 2000 compared to $664.6 million in 1999, an increase of $1,035.5 million, or 156%.

*Electric generation and marketing expense* increased by $432.1 million to $587.2 million in 2000 compared to $155.1 million in 1999 due primarily to an increase of $337.9 million in cost of purchased power by CES in hedging, balancing and related activity, and additionally to the incremental effect of acquisitions made in 1999 such as CCC facilities and the geothermal facilities which reflect a full year of activity in 2000, and due to acquisitions made in 2000. Production royalties increased by $18.5 million to $32.3 million in 2000 compared to $13.8 million in 1999 primarily due to royalties paid to third parties in connection with geothermal energy generation.

*Oil and gas production and marketing expense* increased by $132.4 million to $197.8 million in 2000 compared to $65.4 million in 1999 due primarily to a $95.7 million increase in cost of gas purchased and resold as a result of increased CES hedging, balancing and related activity, in addition to an increase in production combined with higher third-party facility charges.

*Fuel expense* increased by $344.2 million to $612.9 million in 2000 compared to $268.7 million in 1999 due primarily to the incremental effect of acquisitions made in 1999 such as the CCC facilities which reflect a full year of activity in 2000, and due to acquisitions made in 2000. Additionally, we incurred significantly higher gas prices during 2000.

*Depreciation expense* increased by $95.9 million to $230.8 million in 2000 compared to $134.9 million in 1999 primarily due to an approximate $63.6 million increase in depreciation expense relating to our natural gas production. The remainder is substantially the result of the incremental effect of acquisitions that we made during 1999 and 2000.

*Operating lease expense* increased by $35.8 million to $69.4 million in 2000 compared to $33.6 million in 1999. Approximately $15.0 million was due to the lease associated with our acquisition of the remaining 50% interest in KIAC in May 2000. Another $8.7 million was due to the inclusion of a full year's operations of our geothermal facilities, $5.0 million was attributable to the Pasadena sales-leaseback that we entered into in September 2000, and $6.4 million was due to the higher contingent lease payments at our Watsonville facility.

*Project development expense* increased by $16.9 million, or 158%, in 2000 to $27.6 million compared to $10.7 million in 1999 due to

heavier activities in identifying and obtaining acquisition and project development opportunities resulting from a larger number of development projects. For additional information, see “Item 1 — Business — Project Development and Acquisitions.”

*General and administrative expense* — In 2000, general and administrative expense was $102.6 million compared to $55.7 million in 1999. The increase of 84% or $46.9 million is largely attributable to our acquisitions and continued growth in personnel and associated overhead costs necessary to support the overall growth of our operations and construction programs.

*Interest expense* — Interest expense before capitalization of interest was $281.7 million in 2000 compared to $150.5 million in 1999, an increase of $131.2 million due to higher debt balances in 2000. Total debt increased by approximately $2.5 billion due primarily to our public offering of $1 billion of senior notes in August 2000 and due to debt acquired in connection with various acquisitions such as capital leases associated with our Hidalgo, Agnews, and Stony Brook acquisitions. After capitalization of interest on our significant



construction program (see “Item 1 — Business — Project Development and Acquisitions”), our interest expense decreased by approximately $28.5 million in 2000 to $74.7 million from $103.2 million in 1999.

*Distributions on trust preferred securities* — Distributions on trust preferred securities increased to $44.2 million in 2000 from $2.6 million in 1999, due to a full year of distributions on our HIGH TIDES issuance of November 1999, in addition to HIGH TIDES issuances in January and August 2000, respectively.

*Interest income* — In 2000, interest income was $39.9 million compared to $24.1 million in 1999. The increase of 66% or $15.8 million is attributable to higher average cash balances in 2000 owing to the public offerings of senior notes and common stock in August 2000, and due to the public offerings of HIGH TIDES in January and August of 2000.

*Provision for income taxes* — The effective income tax rate was approximately 41% in 2000 compared to approximately 39% in 1999. The rate increase in 2000 is primarily attributable to a higher average tax rate based on the locations in which we operated. In 2000, our provision for federal and state income taxes totaled $264.8 million versus $68.1 million in 1999, an increase of $196.7 million, which is due primarily to higher taxable income in 2000.

***Year Ended December 31, 1999 Compared to Year Ended December 31, 1998***

*Revenue* — Total revenue increased 51% to $983.5 million in 1999 compared to $650.6 million in 1998, primarily due to the impact of recognizing a full year’s income from various assets that were acquired in 1998 and of recognizing a partial year’s income from various assets that were acquired in 1999, as described below.

*Electric generation and marketing revenue* — increased 53% to $783.5 million in 1999 compared to $511.4 million in 1998. Geothermal revenue — at the Geysers accounted for $123.2 million of the total increase of $272.1 million. This was primarily due to the purchase of 14 geothermal power plants from PG&E on May 7, 1999 and, to a much lesser extent, due to the purchases of: (1) an additional 50% stake in the Aidlin Power Plant in August, 1999 after which we consolidated the plant into our financial results; and (2) the Calistoga Power Plant on October 19, 1999. In 1999, our geothermal steamfield sales of steam declined by $3.0 million compared to 1998, due to consolidation of steam field and power plant operations at the Geysers under Calpine ownership in May 1999, after which we stopped recording revenues from geothermal steamfield sales to third parties.

The remainder of the increase in electric generation and marketing revenue is primarily attributable to our gas-fired power plants. In California, the Gilroy Power Plant increased its revenue in 1999 by $27.9 million over 1998 by both (1) doubling its production, mostly as a result of the expiration of PG&E’s curtailment rights on December 31, 1998 and (2) restructuring its power purchase agreement with PG&E, effective as of September 1, 1999. Also, the Pittsburg Power Plant in California increased its revenue by $12.6 million in 1999 versus 1998. We acquired the project on July 21, 1998 and did not have a full year of operations in 1998. In Texas, the Texas City and Clear Lake Power Plants, which were consolidated into our financial statements following the acquisition of the remaining 50% interest of Texas Cogeneration Company (“TCC”) on March 31, 1998, benefited by a full year of operations in 1999 versus only nine months on a consolidated basis in 1998, and together they recorded an additional $39.0 million of revenue in 1999 versus in 1998. Additionally, the Pasadena Power Plant, which commenced operation in July 1998, had $43.6 million of additional revenue in 1999 compared to 1998 due to a full year of operations in 1999. Finally, sales of purchased power increased $19.7 million, from $3.5 million in 1998 to $23.2 million in 1999, as we began the ramp up of electric marketing and related activity.

*Oil and gas production and marketing revenue* increased 53% to $156.0 million in 1999 compared to $101.9 million in 1998. The $54.1 million increase was primarily due to strengthening commodity prices and increased crude oil and natural gas production. Sales of purchased gas increased $7.2 million to $14.4 million in 1999, due to the ramp up of gas hedging, balancing and related activity by CES.

*Income from unconsolidated investments in power projects* increased 45% to $36.6 million in 1999 compared to $25.2 million in 1998. The increase of $11.4 million is primarily attributable to an increase of



equity income from the Sumas Power Plant. In 1999, we recorded $21.8 million versus $11.7 million in 1998, an increase of $10.1 million. Additionally, as a group, our equity income from projects on the East Coast (Lockport Power Plant, Stony Brook Power Plant, Kennedy International Airport Power Plant, Gordonsville Power Plant, Auburndale Power Plant, and Bayonne Power Plant) increased by $4.2 million. This was offset by a $2.9 million reduction in equity income attributable to our Clear Lake and Texas City Power Plants, which were unconsolidated investments for part of 1998 until our purchase of the remaining 50% interest in TCC on March 31, 1998.

*Cost of revenue* — Cost of revenue increased to $664.6 million in 1999 compared to $466.0 million in 1998, an increase of $198.6 million, or 43%.

*Electric generation and marketing expense* increased by $63.2 million to $155.1 million in 1999 compared to $91.9 million in 1998 due primarily to higher geothermal plant operating expense in 1999 following our purchase of 14 geothermal power plants from PG&E on May 7, 1999 and our purchase of geothermal steam field assets from Unocal Corporation on March 19, 1999. Additionally, we incurred an additional $17.6 million relating to the costs associated with the sales of purchased power. Production royalties increased by $3.1 million to $13.8 million in 1999 compared to $10.7 million in 1998 due to our purchase of geothermal steam field assets from Unocal Corporation on March 19, 1999.

*Oil and gas production and marketing expense* increased by $16.8 million to $65.4 million in 1999 compared to $48.6 million in 1998 due primarily to a 9% increase in production combined with higher third-party facility charges. Additionally, $6.3 million of the increase relates to the cost of gas purchased and resold.

*Fuel expense* increased by $87.1 million to $268.7 million in 1999 compared to $181.6 million in 1998 due primarily to: (1) a full year of consolidated operations in 1999 for the Clear Lake and Texas City Power Plants versus only nine months in 1998; (2) a full year of operation in 1999 versus a partial year in 1998 for the Pasadena Power Plant, which commenced commercial operations in July, 1998; (3) a full year of operations in 1999 versus a partial year in 1998 for the Pittsburg Power Plant, which we acquired on July 21, 1998; and (4) higher production in 1999 compared to 1998, and therefore higher fuel expense, at our Gilroy and King City Power Plants due to the expiration of PG&E's curtailment rights on December 31, 1998, and April 28, 1999, respectively.

*Depreciation expense* increased by $16.0 million to $134.9 million in 1999 compared to $118.9 million in 1998 primarily due to a full year of operations in 1999 versus a partial year in 1998 for the Texas City, Clear Lake and Pasadena Power Plants, as noted above, and also due to our purchase of Sheridan Energy on October 1, 1999, and due to increased oil and gas production.

*Operating lease expense* increased by $16.5 million to $33.6 million in 1999 compared to $17.1 million in 1998. Of the increase, $10.8 million is due to the sale-leaseback in May 1999 of the 14 geothermal power plants acquired from PG&E in May 1999 and the Sonoma Power Plant, which we acquired in July 1998. We later added the Calistoga Power Plant, which we acquired in October 1999, to that lease. The remainder of the increase is primarily due to recording a full year of expense in 1999 versus a partial year in 1998 for the Greenleaf 1 and 2 Power Plants, which were leased commencing in August 1998.

*Project development expense* — Project development expense increased by $3.5 million, or 49%, in 1999 to $10.7 million compared to $7.2 million in 1998 due to the overall heavier pace in development activities as described in "Item 1 — Business — Project Development and

Acquisitions."

*General and administrative expense* — In 1999, general and administrative expense was $55.7 million compared to $30.0 million in 1998. The increase of 86% or $25.7 million is largely attributable to the establishment of regional offices in Pleasanton, California and Boston, Massachusetts, the build-up of our Houston, Texas office, and the establishment of our construction management office in Sacramento, California. In addition to higher headcount and salaries associated with our substantial growth, we incurred larger employee bonus expense owing to the record year we experienced in 1999. The increased general and administrative investment in 1999 reflects, in part, increased expenses designed to support our growth in 2000 and beyond.



*Interest expense* — Interest expense before capitalization of interest was $150.5 million in 1999 compared to $102.7 million in 1998, an increase of $47.8 million due to higher debt balances in 1999 (total debt increased by $1 billion due primarily to our public offering of $600.0 million of senior notes on March 29, 1999). However, actual reported interest expense increased by a much smaller $7.5 million, or 8%, in 1999 compared to 1998 because we capitalized substantially more interest in 1999 compared to 1998 due to our heavy power plant construction program. By the fourth quarter of 1999, we had nine construction projects underway. We capitalized $47.3 million of interest expense in 1999 compared to $7.0 million in 1998, which is an increase of $40.3 million in capitalized interest expense.

*Distributions on trust preferred securities* — In October 1999, we completed a public offering by a subsidiary trust of 5,520,000 HIGH TIDES. The accrued distributions through December 31, 1999 were $2.6 million.

*Interest income* — In 1999, interest income was $24.1 million compared to $12.3 million in 1998. The increase of 96% or $11.8 million is attributable to higher average cash balances in 1999 owing to the public offerings of senior notes and common stock in March, 1999, and due to the public offerings of common stock and HIGH TIDES in October 1999.

*Other income (expense), net* — In 1999, other income was $5.1 million compared to $(3.7)million in 1998. The increase is primarily due to foreign currency translation gains.

*Provision for income taxes* — The effective income tax rate was approximately 39% in 1999 compared to approximately 35% in 1998. The rate increase in 1999 is primarily attributable to a higher average state tax rate based on the locations in which we operated. In 1999, our provision for federal and state income taxes totaled $68.1 million versus $21.2 million in 1998, an increase of $46.9 million, which is due primarily to higher taxable income in 1999.

**Liquidity and Capital Resources**

To date, we have obtained cash from our operations; borrowings under our credit facilities and other working capital lines; sales of debt, trust preferred securities and equity; and proceeds from project financing. We utilized this cash to fund our operations; service debt obligations; fund the acquisition, development and construction of power generation facilities; finance capital expenditures; and meet our other cash and liquidity needs. The following table summarizes our cash flow activities for the periods indicated:

| | Years Ended December 31, | | |
|---|---|---|---|
| | **2000** | **1999** | **1998** |
| | | **(in thousands)** | |
| Beginning cash and cash equivalents | $ 349,371 | $ 96,532 | $ 48,513 |
| Cash flows from: | | | |
| Operating activities | 802,550 | 314,361 | 199,709 |
| Investing activities | (3,752,657) | (1,599,456) | (488,834) |
| Financing activities | 3,196,813 | 1,537,934 | 337,144 |
| Net increase in cash and cash equivalents | 246,706 | 252,839 | 48,019 |
| Ending cash and cash equivalents | $ 596,077 | $ 349,371 | $ 96,532 |

Operating activities for 2000 provided $802.6 million, a 155% increase from 1999, consisting of approximately $218.1 million of depreciation and amortization, $372.6 million of net income, $30.0 million of distributions from unconsolidated investments in power projects, $108.5 million of deferred income taxes and a $732.2 million net increase in operating liabilities. This was partially offset by a $633.2 million net increase in operating assets and $24.6 million of income from unconsolidated investments. The increase in cash provided by operating activities in 2000 is primarily due to higher net income derived from our acquisition activity in 1999 and 2000, favorable pricing, and increased

production.

Investing activities for 2000 used $3.8 billion, primarily due to $3.1 billion for construction costs and capital expenditures including gas turbine-generator costs and associated capitalized interest, $840.9 million



for acquisitions (see Note 4 of the Notes to Consolidated Financial Statements for further discussion), $141.1 million of advances to joint ventures including associated capitalized interest for investments in power projects under construction, $53.1 million of capitalized project development costs including associated capitalized interest, $184.5 million increase in notes receivables primarily due to our Delta Energy Center development partner and our long-term Gilroy restructuring receivables and $15.6 million increase in restricted cash related to certain project financings. This was partially offset by $642.2 million in proceeds from sale and leasebacks of power plants and $17.3 million in disposals of property, plant and equipment. The increase in cash used in investing activities in 2000 is primarily due to increased construction and acquisition activity compared to 1999.

Financing activities for 2000 provided $3.2 billion of cash consisting of $1.0 billion proceeds from the issuance of our Senior Notes due 2005 and Senior Notes due 2010, $2.3 billion in borrowings under various credit facilities and $1.7 billion of proceeds from offerings of our common stock and HIGH TIDES. This was offset by $1.7 billion of repayments on various credit facilities and $58.9 million of financing costs. The increase in cash provided from financing activities in 2000 is primarily due to the debt and equity offerings issued during 2000, as well as the HIGH TIDES offerings.

As discussed in Note 20 of the Notes to Consolidated Financial Statements and under the caption “Item 1 — Business — Recent Developments”, there is considerable uncertainty surrounding the California power market. Regardless of the resolution of the current situation, we do not believe that a possible uncollectibility of remaining receivables from PG&E would have a material adverse effect on our liquidity or cash flows. However, failure to collect a significant portion of the receivables could have a materially adverse effect on our Statements of Operations.

We continue to evaluate current and forecasted cash flow as a basis for financing operating requirements and capital expenditures. We believe that we will have sufficient liquidity from cash flow from operations, borrowings available under the lines of credit, access to the capital markets and working capital to satisfy all obligations under outstanding indebtedness, to finance anticipated capital expenditures and to fund working capital requirements for the next twelve months.

*Credit Facilities and Notes Payable (see Note 7 of the Notes to Consolidated Financial Statements)*

At December 31, 2000, we maintained a borrowing base in Canada of Cdn $304.0 million (US $202.7 million) under three facilities. At December 31, 2000, we had US $144.5 million outstanding under these facilities. The facilities bear interest at variable rates. The weighted average rate for each of the facilities in 2000 was 8.52%. Additionally, commitment fees of 0.25% accrue on any unused portion of these facilities.

At December 31, 2000 we had an unsecured Cdn $370.0 million (US $246.8 million) term credit facility and a Cdn $30.0 million (US $20.0 million) operating credit facility from Canadian chartered banks of which Cdn $238.7 million (US $159.2 million) and Cdn $229.2 million (US $158.7 million) was outstanding under the term credit facility at December 31, 2000 and 1999, respectively. The borrowings bear variable interest. Interest rates averaged 7.23% and 6.45% for 2000 and 1999, respectively.

At December 31, 2000, we, through our wholly owned Canadian subsidiaries, had two separate issues of $50.0 million unsecured notes. The first issue bears interest at 7.61% and matures on July 11, 2007. These notes are repayable in five equal annual installments of $10.0 million beginning July 11, 2003, with interest payable semi-annually in arrears until maturity. The second issue bears interest at 8.06% with a 10-year term maturing December 21, 2010. These 8.06% notes are repayable in five equal, annual installments of $10.0 million beginning December 21, 2006 with interest payable quarterly in arrears until maturity.

In 1999, we, through our wholly owned subsidiary Calpine Natural Gas Company (“CNGC”), maintained a borrowing base of $99.1 million with Bank One, Texas N.A. under two facilities. In August 2000, we repaid the outstanding balance of $93.3 million and terminated the agreement. As of December 31, 1999, CNGC had total borrowings of $97.8 million outstanding under this facility. The facility bore interest at variable rates. At December 31, 1999, the interest rate was 8.6%. The lines of credit were secured by CNGC’s oil and gas properties.



At December 31, 2000, we had an amended and restated $400.0 million, three-year revolving line of credit with a consortium of

commercial lending institutions with the Bank of Nova Scotia as agent, which replaced an existing $100.0 million credit facility. A maximum of $200.0 million of the credit facility may be allocated to letters of credit. At December 31, 2000, we had $40.0 million in borrowings and $157.9 million of letters of credit outstanding under the amended and restated credit facility. At December 31, 1999, we had no borrowings and $28,800 in letters of credit outstanding under this credit facility. The interest rate ranged from 7.88% to 9.75% during 2000.

*Project Financing (see Note 8 of the Notes to Consolidated Financial Statements)*

In November 1999, we entered into a credit agreement for $1.0 billion through our wholly owned subsidiary Calpine Construction Finance Company L.P. with a consortium of banks with the lead arranger being The Bank of Nova Scotia and the lead arranger syndication agent being Credit Suisse First Boston. The non-recourse credit facility is utilized to finance the construction of our diversified portfolio of gas-fired power plants currently under development. We currently intend to refinance this construction facility in the long-term capital markets prior to its four-year maturity. As of December 31, 2000, we had $544.8 million in borrowings outstanding under the facility. Borrowings under this facility bear variable interest.

In October 2000, we entered into a credit agreement for $2.5 billion through our wholly owned subsidiary Calpine Construction Finance Company II, LLC with a consortium of banks with the lead arrangers being The Bank of Nova Scotia and Credit Suisse First Boston. The non-recourse credit facility is utilized to finance the construction of our diversified portfolio of gas-fired power plants currently under development. We currently intend to refinance this construction facility in the long-term capital markets prior to its four-year maturity. As of December 31, 2000, we had $156.8 million in borrowings outstanding under the facility. Borrowings under this facility bear variable interest.

As part of our acquisition of the Auburndale Power Plant, we assumed a facility that provides for project financing loans aggregating $126.0 million. Amounts outstanding under the facility bear variable interest. The weighted average interest rate for this facility was 7.51% during 2000 and $121.5 million was outstanding under the facility at December 31, 2000.

On December 17, 1999, we acquired 80% of the common stock of CCC which owns 100% of the Newark and Parlin Power Plants (“Newark & Parlin”). As of December 31, 1999, there was $125.3 million outstanding on a 15-year non-recourse term loan which is a joint and severable liability of Newark and Parlin. The interest rate on the outstanding principal is variable. As of December 31, 2000, $116.7 million was outstanding under the facility. The weighted average interest rate during 2000 was 7.68%.

As part of our acquisition of SkyGen, we assumed a term loan for the Broad River Energy Center and a steam injection addition loan, with the latter expected to be converted to a term loan in 2001. Both the project loan and the steam injection addition loan mature on March 1, 2007. The construction loans require only variable interest payments through the conversion date, and blended payments of principal and interest following conversion to a term loan. As of December 31, 2000, $115.9 million was outstanding under the facilities. The weighted average interest rate during 2000 was 8.02%.

As part of our acquisition of SkyGen, we entered into financing to construct the Pine Bluff Energy Center. As part of the related credit agreement, the lenders will provide a facility whereby we can borrow up to $142.0 million to fund construction. Of this amount, $32.0 million is secured by guarantees or letters of credit from the members or their affiliates. Upon completion of construction (the “Conversion Date”), equity contributions of $32.0 million will be made to repay a portion of the construction loan and the balance of the construction loan will be converted to a term loan. The term loan will consist of three tranches: Tranche A in the amount of $30.0 million with a maturity date of 8 1/2 years from the Conversion Date, Tranche B in the amount of $45.0 million with a maturity date of 13 1/2 years from the Conversion Date, and Tranche C in the amount of $35.0 million with a maturity date of 17 1/2 years from the Conversion Date. Interest on the construction loan is variable. For 2000, the interest rate averaged 8.22%. As of December 31, 2000, we had $113.2 million in outstanding borrowings.



As part of our acquisition of SkyGen, we entered into an arrangement with a syndicate of commercial banks to obtain financing to construct the Hog Bayou Energy Center. As part of the related credit agreement, the lenders will provide a facility to fund construction whereby we can borrow up to $38.0 million under an equity bridge loan and $104.6 million under a construction loan. The equity bridge loan matures on December 31, 2001 and the construction loan matures on December 31, 2002. As of December 31, 2000, we had borrowed $38.0 million under the equity bridge loan and $70.0 million under the construction loan. The facilities had a weighted average interest rate of 8.24% during 2000.

As part of our acquisition of SkyGen, we entered into financing for the construction of the RockGen Energy Center. As part of the related credit agreement, the lender provided a facility whereby we can borrow up to $152.6 million to fund construction. Construction loans consist of a project loan of $143.7 million and a steam injection addition loan of $8.9 million. Upon completion of construction, the balance of the construction loans will be converted to a term loan. The term loan consists of two tranches: Tranche A in the amount of $143.7 million, and Tranche B in the amount of $8.9 million. Both the project loan and the steam injection addition loan mature on March 1, 2007. Interest on the construction loans is variable. As of December 31, 2000, we had borrowings of $89.8 million. The weighted average interest rate during 2000 was 7.97%.

On December 17, 1999, we acquired 80% of the common stock of CCC which owns 100% of Morris LLC (“Morris”). In 1997, Morris entered into a construction and term loan agreement to provide non-recourse project financing for a major portion of the Morris Power Plant.

The agreement provides $85.6 million of 5-year term loan commitments and $5.4 million in letter of credit commitments. As of December 31, 2000, $85.6 million was outstanding as a term loan under the agreement and no amounts were pledged under letters of credit. Interest on the term loan is variable. The weighted average interest rate during 2000 was 7.39%.

As part of our acquisition of SkyGen, we assumed a term loan for the DePere Energy Center, which had a weighted average interest rate of 7.68% during 2000. As of December 31, 2000, we had $47.2 million of outstanding borrowings.

In December 2000, we acquired the remaining interest in the Dighton Power Plant. We assumed project financing for the plant. The weighted average interest rate during 2000 was 7.79%. At December 31, 2000, we had $32.8 million of outstanding borrowings.

In August 1996, we entered into an agreement with Banque Nationale de Paris ("BNP") to finance the acquisition of the Gilroy Power Plant. In April 1999, we repaid the entire loan of $120.6 million to BNP with a portion of the net proceeds from the offering of Senior Notes due 2006. We recorded an extraordinary loss of $1.2 million after taxes as a result of the repayment for the write-off of unamortized deferred financing cost associated with the BNP financing.

On January 4, 1999, we entered into a credit agreement with ING (U.S.) Capital LLC to provide up to $265.0 million of non-recourse project financing for the construction of the Pasadena facility expansion. On August 31, 2000, we repaid the outstanding balance of $224.2 million under the credit agreement.

*Capital Markets Offerings (see Notes 9, 11 and 14 of the Notes to Consolidated Financial Statements)*

On February 10, 2000, we, through our wholly owned subsidiary, Calpine Capital Trust II, a statutory business trust created under Delaware law, completed a private offering of 7,200,000 HIGH TIDES at a price of $50.00 per share. The gross proceeds from the offering were $360.0 million. The net proceeds from the private offering were used by our subsidiary to invest in our convertible subordinated debentures, which represent substantially all of the subsidiary's assets.

On August 9, 2000, we completed a public offering of 23,000,000 shares of our common stock at $34.75 per share. The gross proceeds from the offering were $799.3 million.

On August 9, 2000, we, through our wholly owned subsidiary, Calpine Capital Trust III, a statutory business trust created under Delaware law, completed a private offering of 10,350,000 HIGH TIDES at a price of $50.00 per share. The gross proceeds from the offering were $517.5 million. The net proceeds from the



private offering were used by our subsidiary to invest in our convertible subordinated debentures, which represent substantially all of the subsidiary's assets.

On August 10, 2000, we completed a public offering of $250.0 million of our 8 1/4% Senior Notes due 2005 and $750.0 million of our 8 5/8% Senior Notes due 2010. The 8 1/4% Senior Notes mature on August 15, 2005 and interest is payable semi-annually. The 8 5/8% Senior Notes mature on August 15, 2010 and interest is payable semi-annually. Both issuances of senior notes may be redeemed at any time prior to their respective stated maturity at a redemption price equal to 100% of the principal amount of the senior notes being redeemed plus accrued and unpaid interest plus a make-whole premium.

*Debt Maturities*

At December 31, 2000, we also had $105.0 million of outstanding 9 1/4% Senior Notes due 2004, which mature on February 1, 2004, with interest payable semi-annually on February 1 and August 1 of each year. In addition, we had $171.8 million of outstanding 10 1/2% Senior Notes due 2006, which mature on May 15, 2006, with interest payable semi-annually on May 15 and November 15 of each year. During 1997, we issued $275.0 million of 8 3/4% Senior Notes due 2007, which mature on July 15, 2007, with interest payable semi-annually on January 15 and July 15 of each year. During 1998, we issued $400.0 million of 7 7/8% Senior Notes due 2008, which mature on April 1, 2008, with interest payable semi-annually on April 1 and October 1 of each year. During 1999, we issued $350.0 million of 7 3/4% Senior Notes due 2009, which mature on April 15, 2009, with interest payable semi-annually on April 15 and October 15 of each year. Also during 1999, we issued $250.0 million of our 7 5/8% Senior Notes due 2006, which mature on April 15, 2006, with interest payable semi-annually on April 15 and October 15. During 2000, we issued $250.0 million of 8 1/4% Senior Notes due 2005, which mature on August 15, 2005, with interest payable semi-annually on August 15 and February 15 of each year. Also during 2000, we issued $750.0 million of 8 1/4% Senior Notes due 2010, which mature on August 15, 2010, with interest payable semi-annually on August 14 and February 15 of each year.

The annual principal maturities of the borrowings under lines of credit, project financing, notes payable, senior notes and capital lease obligations as of December 31, 2000, are as follows (in thousands):

| | |
|---|---|
| 2001 | $ 61,558 |
| 2002 | 98,151 |
| 2003 | 625,616 |
| 2004 | 381,115 |
| 2005 | 293,938 |
| Thereafter | 3,290,742 |
| Total | $4,751,120 |

**Outlook**

Our strategy is to continue our rapid growth by capitalizing on the significant opportunities in the power industry, primarily through our active development and acquisition programs. In pursuing our proven growth strategy, we utilize our extensive management and technical expertise to implement a fully integrated approach to the acquisition, development and operation of power generation facilities. This approach uses our expertise in design, engineering, procurement, finance, construction management, fuel and resource acquisition, operations and power marketing, which we believe provides us with a competitive advantage. The key elements of our strategy are as follows:

- *Development of new and expansion of existing power plants.* We are actively pursuing the development of new and expansion of both baseload and peaking capacity at our existing highly efficient, low-cost, gas-fired power plants that replace old and inefficient generating facilities and meet the demand for new generation. Our strategy is to develop power plants in strategic geographic locations that enable us to leverage existing power generation assets and operate the power plants as integrated electric generation systems. This allows us to achieve significant operating synergies and efficiencies in fuel procurement, power marketing, and operations and maintenance.



As of April 19, 2001, we have 27 projects under construction, representing an additional 14,520 megawatts of net capacity. Included in these 27 projects is an expansion of our Broad River Energy Center, which represents 360 megawatts. We have also announced plans to develop 31 additional power generation projects, representing a net capacity of 17,785 megawatts. Included in these 31 development projects are 7 expansion projects: Pine Bluff Energy Center, DePere Energy Center, Auburndale and the California Peakers (which encompasses expansions of the Gilroy Power Plant, the Watsonville Power Plant, the Greenleaf 2 Power Plant and the King City Power Plant.) These expansion projects represent 932 megawatts.

- *Acquisition of power plants.* Our strategy is to acquire power generating facilities that meet our stringent acquisition criteria and provide significant potential for revenue, cash flow and earnings growth, and that provide the opportunity to enhance the operating efficiencies of the plants. We have significantly expanded and diversified our project portfolio through numerous acquisitions of power generation facilities to date.

- *Enhance the performance and efficiency of existing power projects.* We continually seek to maximize the power generation potential of our operating assets and minimize our operating and maintenance expenses and fuel costs. This will become even more significant as our portfolio of power generation facilities expands to 75 power plants with a net capacity of 20,357 megawatts after completion of our projects currently under construction. We focus on operating our plants as an integrated system of power generation, which enables us to minimize costs and maximize operating efficiencies. We believe that achieving and maintaining a low cost of production will be increasingly important to compete effectively in the power generation industry.

**Risk Factors**

*We have substantial indebtedness that we may be unable to service and that restricts our activities.* We have substantial debt that we incurred to finance the acquisition and development of power generation facilities. As of December 31, 2000, our total consolidated indebtedness was $4.8 billion, our total consolidated assets were $10.3 billion and our stockholders' equity was $2.4 billion. Whether we will be able to meet our debt service obligations and repay our outstanding indebtedness will be dependent primarily upon the performance of our power generation facilities.

This high level of indebtedness has important consequences, including:

- limiting our ability to borrow additional amounts for working capital, capital expenditures, debt service requirements, execution of our growth strategy, or other purposes;
- limiting our ability to use operating cash flow in other areas of our business because we must dedicate a substantial portion of these funds to service the debt;
- increasing our vulnerability to general adverse economic and industry conditions; and
- limiting our ability to capitalize on business opportunities and to react to competitive pressures and adverse changes in government regulation.

The operating and financial restrictions and covenants in certain of our existing debt agreements limit or prohibit our ability to:

- incur indebtedness;
- make prepayments of indebtedness in whole or in part;
- pay dividends;
- make investments;
- engage in transactions with affiliates;
- create liens;



- sell assets; and
- acquire facilities or other businesses.

Also, if our management or ownership changes, the indentures governing our senior notes may require us to make an offer to purchase our senior notes. We cannot assure that we will have the financial resources necessary to purchase our senior notes in this event.

We believe that our cash flow from operations, together with other available sources of funds, including borrowings under our existing borrowing arrangements, will be adequate to pay principal and interest on our senior notes and other debt and to enable us to comply with the terms of our indentures and other debt agreements. If we are unable to comply with the terms of our indentures and other debt agreements and fail to generate sufficient cash flow from operations in the future, we may be required to refinance all or a portion of our senior notes and other debt or to obtain additional financing. However, we may be unable to refinance or obtain additional financing because of our high levels of debt and the debt incurrence restrictions under our indentures and other debt agreements. If cash flow is insufficient and refinancing or additional financing is unavailable, we may be forced to default on our senior notes and other debt obligations. In the event of a default under the terms of any of our indebtedness, the debt holders may accelerate the maturity of our obligations, which could cause defaults under our other obligations.

*Our ability to repay our debt depends upon the performance of our subsidiaries.* Almost all of our operations are conducted through our subsidiaries and other affiliates. As a result, we depend almost entirely upon their earnings and cash flow to service our indebtedness, including our ability to pay the interest on and principal of our senior notes. The project financing agreements of certain of our subsidiaries and other affiliates generally restrict their ability to pay dividends, make distributions, or otherwise transfer funds to us prior to the payment of other obligations, including operating expenses, debt service and reserves.

Our subsidiaries and other affiliates are separate and distinct legal entities and have no obligation to pay any amounts due on our senior notes, and do not guarantee the payment of interest on or principal of these notes. The right of our senior note holders to receive any assets of any of our subsidiaries or other affiliates upon our liquidation or reorganization will be subordinated to the claims of any subsidiaries' or other affiliates' creditors (including trade creditors and holders of debt issued by our subsidiaries or affiliates). As of December 31, 2000, our subsidiaries had $1.5 billion of project financing. We intend to utilize project financing, when appropriate in the future, and this financing will be effectively senior to our senior notes.

While the indentures impose limitations on our ability and the ability of our subsidiaries to incur additional indebtedness, the indentures do not limit the amount of project financing that our subsidiaries may incur to finance the acquisition and development of new power generation facilities.

*We may be unable to secure additional financing in the future.* Each power generation facility that we acquire or develop will require substantial capital investment. Our ability to arrange financing and the cost of the financing are dependent upon numerous factors. These factors include:

- general economic and capital market conditions;
- conditions in energy markets;
- regulatory developments;
- credit availability from banks or other lenders;
- investor confidence in the industry and in us;
- the continued success of our current power generation facilities; and
- provisions of tax and securities laws that are conducive to raising capital.

*Financing for new facilities may not be available to us on acceptable terms in the future.* We have financed our existing power generation facilities using a variety of leveraged financing structures, consisting of senior unsecured indebtedness, project financing and lease obligations. Most of our current construction costs



are financed through one of our two Calpine Construction Finance Company ("CCFC") non-recourse debt facilities (see Note 8 of the Notes to Consolidated Financial Statements). As construction projects attain commercial operation, we intend to refinance construction debt borrowings under the CCFC facilities with corporate level long-term capital market financings. As of December 31, 2000, we had approximately $4.8 billion of total consolidated indebtedness, $1.5 billion of project financing, $210.9 million of capital lease obligations, $2.6 billion in senior notes and $456.2 million of notes payable and borrowings under lines of credit. Each project financing and lease obligation is structured to be fully paid out of cash flow provided by the facility or facilities. In the event of a default under a financing agreement which we do not cure, the lenders or lessors would generally have rights to the facility and any related assets. In the event of foreclosure after a default, we might not retain any interest in the facility. While we intend to utilize non-recourse or lease financing when appropriate, market conditions and other factors may prevent similar financing for future facilities. We do not believe the existence of non-recourse or lease financing will significantly affect our ability to continue to borrow funds in the future in order to finance new facilities. However, it is possible that we may be unable to obtain the financing required to develop our power generation facilities on terms satisfactory to us.

We have from time to time guaranteed certain obligations of our subsidiaries and other affiliates. Our lenders or lessors may also require us to guarantee the indebtedness for future facilities. This would render our general corporate funds vulnerable in the event of a default by the facility or related subsidiary. Additionally, our indentures may restrict our ability to guarantee future debt, which could adversely affect our ability to fund new facilities. Our indentures do not limit the ability of our subsidiaries to incur non-recourse or lease financing for investment in new facilities.

*Revenue under some of our power sales agreements may be reduced significantly upon their expiration or termination.* Most of the electricity we generate from our existing portfolio is sold under long-term power sales agreements that expire at various times. When the terms of each of these power sales agreements expire, it is possible that the price paid to us for the generation of electricity may be reduced significantly, which would substantially reduce our revenue under such agreements.

*Our power project development and acquisition activities may not be successful.* The development of power generation facilities is subject to substantial risks. In connection with the development of a power generation facility, we must generally obtain:

- necessary power generation equipment;
- governmental permits and approvals;
- fuel supply and transportation agreements;

- sufficient equity capital and debt financing;
- electrical transmission agreements; and
- site agreements and construction contracts.

We may be unsuccessful in accomplishing any of these matters or in doing so on a timely basis. In addition, project development is subject to various environmental, engineering and construction risks relating to cost-overruns, delays and performance. Although we may attempt to minimize the financial risks in the development of a project by securing a favorable power sales agreement, obtaining all required governmental permits and approvals, and arranging adequate financing prior to the commencement of construction, the development of a power project may require us to expend significant sums for preliminary engineering, permitting and legal, and other expenses before we can determine whether a project is feasible, economically attractive or financeable. If we were unable to complete the development of a facility, we would generally not be able to recover our investment in the project. The process for obtaining initial environmental, siting and other governmental permits and approvals is complicated and lengthy, often taking more than one year, and is subject to significant uncertainties. We cannot assure that we will be successful in the development of power generation facilities in the future.



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*We have grown substantially in recent years as a result of acquisitions of interests in power generation facilities and steam fields.* We believe that although the domestic power industry is undergoing consolidation and significant acquisition opportunities are available, we are likely to confront significant competition for acquisition opportunities. In addition, we may be unable to continue to identify attractive acquisition opportunities at favorable prices or, to the extent that any opportunities are identified, we may be unable to complete the acquisitions.

*Our projects under construction may not commence operation as scheduled.* The commencement of operation of a newly constructed power generation facility involves many risks, including:

- start-up problems;
- the breakdown or failure of equipment or processes; and
- performance below expected levels of output or efficiency.

New plants have no operating history and may employ recently developed and technologically complex equipment. Insurance is maintained to protect against certain risks, warranties are generally obtained for limited periods relating to the construction of each project and its equipment in varying degrees, and contractors and equipment suppliers are obligated to meet certain performance levels. The insurance, warranties or performance guarantees, however, may not be adequate to cover lost revenues or increased expenses. As a result, a project may be unable to fund principal and interest payments under its financing obligations and may operate at a loss. A default under such a financing obligation could result in losing our interest in a power generation facility.

In addition, power sales agreements entered into with a utility early in the development phase of a project may enable the utility to terminate the agreement, or to retain security posted as liquidated damages, if a project fails to achieve commercial operation or certain operating levels by specified dates or fails to make specified payments. In the event a termination right is exercised, the default provisions in a financing agreement may be triggered (rendering such debt immediately due and payable). As a result, the project may be rendered insolvent and we may lose our interest in the project.

*Our power generation facilities may not operate as planned.* Upon completion of our projects currently under construction, we will operate 71 of the 75 power plants in which we will have an interest. The continued operation of power generation facilities involves many risks, including the breakdown or failure of power generation equipment, transmission lines, pipelines or other equipment or processes, and performance below expected levels of output or efficiency. Although from time to time our power generation facilities have experienced equipment breakdowns or failures, these breakdowns or failures have not had a significant effect on the operation of the facilities or on our results of operations. For calendar year 2000, our gas-fired and geothermal power generation facilities have operated at an average availability of approximately 90% and 97%, respectively. Although our facilities contain various redundancies and back-up mechanisms, a breakdown or failure may prevent the affected facility from performing under applicable power sales agreements. In addition, although insurance is maintained to protect against operating risks, the proceeds of insurance may not be adequate to cover lost revenues or increased expenses. As a result, we could be unable to service principal and interest payments under our financing obligations which could result in losing our interest in the power generation facility.

*Our geothermal energy reserves may be inadequate for our operations.* The development and operation of geothermal energy resources are subject to substantial risks and uncertainties similar to those experienced in the development of oil and gas resources. The successful

exploitation of a geothermal energy resource ultimately depends upon:

- the heat content of the extractable fluids;
- the geology of the reservoir;
- the total amount of recoverable reserves;
- operating expenses relating to the extraction of fluids;



- price levels relating to the extraction of fluids or power generated; and
- capital expenditure requirements relating primarily to the drilling of new wells.

In connection with each geothermal power plant, we estimate the productivity of the geothermal resource and the expected decline in productivity. The productivity of a geothermal resource may decline more than anticipated, resulting in insufficient reserves being available for sustained generation of the electrical power capacity desired. An incorrect estimate by us or an unexpected decline in productivity could lower our results of operations.

Geothermal reservoirs are highly complex. As a result, there exist numerous uncertainties in determining the extent of the reservoirs and the quantity and productivity of the steam reserves. Reservoir engineering is an inexact process of estimating underground accumulations of steam or fluids that cannot be measured in any precise way, and depends significantly on the quantity and accuracy of available data. As a result, the estimates of other reservoir specialists may differ materially from ours. Estimates of reserves are generally revised over time on the basis of the results of drilling, testing and production that occur after the original estimate was prepared. While we have extensive experience in the operation and development of geothermal energy resources and in preparing such estimates, we cannot assure that we will be able to successfully manage the development and operation of our geothermal reservoirs or that we will accurately estimate the quantity or productivity of our steam reserves.

*The current issues in the California power market could adversely affect our performance.* As described within, the California power market is currently in a state of disarray. PG&E, one of our customers, has defaulted on payments to us and filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code on April 6, 2001. State and federal regulators and legislators, along with the major participants in the market and consumer groups, are attempting to resolve this situation, but the ultimate result of this effort is not yet known. We are actively involved in all aspects of this regulatory, legislative and contractual effort. While we cannot predict the outcome of this very fluid process, or the ultimate impact any such outcome will have upon us, management believes that the resolution of this problem will not have a material adverse effect on our results of operations or financial condition.

*We depend on our electricity and thermal energy customers.* A majority of our power generation facilities currently relies on one or more power sales agreements with one or more utilities or other customers for all or substantially all of such facility's revenue. In addition, sales of electricity to two utility customers during 2000, PG&E and Texas Utilities Electric Company, comprised approximately 24.5% and 7.2%, respectively, of our total revenue that year. The loss of significant power sales agreements with either of these customers could have a negative effect on our results of operations. In addition, any material failure by any customer to fulfill its obligations under a power sales agreement could have a negative effect on the cash flow available to us and on our results of operations.

*We are subject to complex government regulation which could adversely affect our operations.* Our activities are subject to complex and stringent energy, environmental and other governmental laws and regulations. The construction and operation of power generation facilities require numerous permits, approvals and certificates from appropriate federal, state and local governmental agencies, as well as compliance with environmental protection legislation and other regulations. While we believe that we have obtained the requisite approvals for our existing operations and that our business is operated in accordance with applicable laws, we remain subject to a varied and complex body of laws and regulations that both public officials and private individuals may seek to enforce. Existing laws and regulations may be revised or reinterpreted, or new laws and regulations may become applicable to us that may have a negative effect on our business and results of operations. We may be unable to obtain all necessary licenses, permits, approvals and certificates for proposed projects, and completed facilities may not comply with all applicable permit conditions, statutes or regulations. In addition, regulatory compliance for the construction of new facilities is a costly and time-consuming process. Intricate and changing environmental and other regulatory requirements may necessitate substantial expenditures to obtain permits. If a project is unable to function as planned due to changing requirements or local opposition, it may create expensive delays or significant loss of value in a project.

Our operations are potentially subject to the provisions of various energy laws and regulations, including PURPA, the Public Utility Holding Company Act of 1935, as amended, ("PUHCA"), and state and local regulations. PUHCA provides for the extensive regulation of public utility holding companies and their subsidiaries. PURPA provides QFs (as defined under PURPA) and owners of QFs exemptions from certain federal and state regulations, including rate and financial regulations.

Under present federal law, we are not subject to regulation as a holding company under PUHCA, and will not be subject to such regulation as long as the plants in which we have an interest (1) qualify as QFs, (2) are subject to another exemption or waiver or (3) qualify as an Exempt Wholesale Generator ("EWG") under the Energy Policy Act of 1992. In order to be a QF, a facility must be not more than 50% owned by one or more electric utility companies or electric utility holding companies. In addition, a QF that is a cogeneration facility, such as the plants in which we currently have interests, must produce electricity as well as thermal energy for use in an industrial or commercial process in specified minimum proportions. The QF also must meet certain minimum energy efficiency standards. Generally, any geothermal power facility which produces up to 80 megawatts of electricity and meets PURPA ownership requirements is considered a QF.

If any of the plants in which we have an interest lose their QF status or if amendments to PURPA are enacted that substantially reduce the benefits currently afforded QFs, we could become a public utility holding company, which could subject us to significant federal, state and local regulation, including rate regulation. If we become a holding company, which could be deemed to occur prospectively or retroactively to the date that any of our plants loses its QF status, all our other power plants could lose QF status because, under FERC regulations, a QF cannot be owned by an electric utility or electric utility holding company. In addition, a loss of QF status could, depending on the particular power purchase agreement, allow the power purchaser to cease taking and paying for electricity or to seek refunds of past amounts paid and thus could cause the loss of some or all contract revenues or otherwise impair the value of a project. If a power purchaser were to cease taking and paying for electricity or seek to obtain refunds of past amounts paid, there can be no assurance that the costs incurred in connection with the project could be recovered through sales to other purchasers. Such events could adversely affect our ability to service our indebtedness, including our senior notes. See "Item 1 — Business — Government Regulation — Federal Energy Regulation — Federal Power Act Regulation."

Currently, Congress is considering proposed legislation that would amend PURPA by eliminating the requirement that utilities purchase electricity from QFs at prices based on avoided costs of energy. We do not know whether this legislation will be passed or, if passed, what form it may take. We cannot provide assurance that any legislation passed would not adversely affect our existing domestic projects.

In addition, many states are implementing or considering regulatory initiatives designed to increase competition in the domestic power generation industry and increase access to electric utilities' transmission and distribution systems for independent power producers and electricity consumers. In particular, the state of California has restructured its electric industry by providing for a phased-in competitive power generation industry, with a power pool (which had discontinued the bulk of its operation as of February 1, 2001) and an independent system operator, and for direct access to generation for all power purchasers outside the power exchange under certain circumstances. See "Item 1 — Business — Recent Developments — California Power Market."

*We may be unable to obtain an adequate supply of natural gas in the future.* To date, our fuel acquisition strategy has included various combinations of our own gas reserves, gas prepayment contracts and short, medium and long-term supply contracts. In our gas supply arrangements, we attempt to match the fuel cost with the fuel component included in the facility's power sales agreements in order to minimize a project's exposure to fuel price risk. We believe that there will be adequate supplies of natural gas available at reasonable prices for each of our facilities when current gas supply agreements expire. However, gas supplies may not be available for the full term of the facilities' power sales agreements, and gas prices may increase significantly. If gas is not available, or if gas prices increase above the fuel component of the facilities' power sales agreements, there could be a negative impact on our results of operations.

*Competition could adversely affect our performance.* The power generation industry is characterized by intense competition, and we encounter competition from utilities, industrial companies and other independent



power producers. In recent years, there has been increasing competition in an effort to obtain power sales agreements, and this competition has contributed to a reduction in electricity prices in certain markets. In addition, many states are implementing or considering regulatory initiatives designed to increase competition in the domestic power industry. In California, the CPUC issued decisions that provide for direct access for all customers as of April 1, 1998; however uncertainty exists as to the future course for direct access in California in the aftermath of the recent energy crisis in that state. In Texas, recently enacted legislation phases-in a deregulated power market commencing January 1, 2001. Regulatory initiatives are also being considered in other states, including New York and states in New England. This competition has put pressure on electric utilities to lower their costs, including the cost of purchased electricity, and increasing competition in the supply of electricity in the future will increase this pressure. See "Item 1 — Business — Recent Developments — California Power Market."

*Our international investments may face uncertainties.* We have an investment in geothermal steam fields located in Mexico and investments in oil and natural gas resources and power development projects in Canada and we may pursue additional international investments. International investments are subject to unique risks and uncertainties relating to the political, social and economic structures of

the countries in which we invest. Risks specifically related to investments in non-United States projects may include:

- fluctuations in currency valuation;
- currency inconvertibility;
- expropriation and confiscatory taxation;
- increased regulation; and
- approval requirements and governmental policies limiting returns to foreign investors.

*We depend on our senior management.* Our success is largely dependent on the skills, experience and efforts of our senior management. The loss of the services of one or more members of our senior management could have a negative effect on our business, financial results and future growth.

*Seismic disturbances could damage our projects.* Areas where we operate and are developing many of our geothermal and gas-fired projects are subject to frequent low-level seismic disturbances. More significant seismic disturbances are possible. Our existing power generation facilities are built to withstand relatively significant levels of seismic disturbances, and we believe we maintain adequate insurance protection. However, earthquake, property damage or business interruption insurance may be inadequate to cover all potential losses sustained in the event of serious seismic disturbances. Additionally, insurance may not continue to be available to us on commercially reasonable terms.

*Our results are subject to quarterly and seasonal fluctuations.* Our quarterly operating results have fluctuated in the past and may continue to do so in the future as a result of a number of factors, including:

- the timing and size of acquisitions;
- the completion of development projects;
- variations in levels of production; and
- seasonal variations in energy prices.

Additionally, because we receive the majority of capacity payments under some of our power sales agreements during the months of May through October, our revenues and results of operations are, to some extent, seasonal.



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*The price of our common stock is volatile.* The market price for our common stock has been volatile in the past, and several factors could cause the price to fluctuate substantially in the future. These factors include:

- announcements of developments related to our business;
- fluctuations in our results of operations;
- sales of substantial amounts of our securities into the marketplace;
- general conditions in our industry, the power markets in which we participate, or the worldwide economy;
- an outbreak of war or hostilities;
- a shortfall in revenues or earnings compared to securities analysts’ expectations;
- changes in analysts’ recommendations or projections; and
- announcements of new acquisitions or development projects by us.

The market price of our common stock may fluctuate significantly in the future, and these fluctuations may be unrelated to our performance. General market price declines or market volatility in the future could adversely affect the price of our common stock, and the current market price may not be indicative of future market prices.



**Exhibit V.**

**Item 7a.** ***Quantitative and Qualitative Disclosure about Market Risk***

**Financial Market Risks**

From time to time, we use interest rate swap agreements to mitigate our exposure to interest rate fluctuations. We do not use such instruments for speculative or trading purposes. The following table summarizes the fair market value of our existing interest rate swap agreements as of December 31, 2000 (dollars in thousands):

| Maturity Date | Notional Principal Amount | Weighted Average Interest Rate | Fair Market Value |
|---|---|---|---|
| 2001 | $ 59,934 | 7.4% | $ (501) |
| 2001 | 33,345 | 6.8% | (1) |
| 2007 | 38,150 | 8.0% | (3,431) |
| 2007 | 38,150 | 8.0% | (3,414) |
| 2007 | 30,708 | 7.9% | (3,178) |
| 2007 | 30,708 | 7.9% | (3,161) |
| 2009 | 15,000 | 6.9% | (601) |
| 2011 | 59,433 | 6.9% | (2,491) |
| 2012 | 121,464 | 6.5% | (3,677) |
| 2014 | 72,277 | 6.7% | (2,608) |
| 2015 | 22,500 | 7.0% | (1,523) |
| 2017 | 50,425 | 5.9% | 868 |
| 2018 | 17,500 | 7.0% | (1,426) |
| Total | $589,594 | 7.0% | $ (25,144) |

*Short-term investments.* As of December 31, 2000, we have short-term investments of $149.2 million. These short-term investments consist of highly liquid investments with maturities less than three months. We have the ability to hold these investments to maturity, and as a result, we would not expect the value of these investments to be affected to any significant degree by a sudden change in market interest rates.

*Energy price fluctuations.* We enter into derivative commodity instruments to reduce our exposure to the impact of price fluctuations, primarily electricity and natural gas prices or, in some cases, to profit from such fluctuations. Such instruments include over-the-counter financial swaps and physical options with major energy derivative product specialists. All transactions are subject to the limitations and guidelines in our risk management policy. Financial swaps are accounted for under the hedge method of accounting. Current revenues and costs reflect the full effect of price movement on physical options. Cash flows from derivative instruments are recognized as incurred through changes in working capital.

The fair value gain (loss) of outstanding derivative commodity instruments and the change in fair value that would be expected from a ten percent adverse price change are shown in the table below (in thousands):

| At December 31, 2000 | Fair Value | Change in Fair Value From 10% Adverse Price Change |
|---|---|---|
| Refined Products | $ (50) | $ (35) |
| Crude Oil | 321 | (336) |
| Electricity | (2,937) | (429) |
| Natural Gas | 105,825 | (71,964) |

| | | |
|---|---|---|
| Total(1) | $103,159 | $(72,764) |

(1) Total includes the fair market value of the physical options of $1.2 million, excluded in "Energy Marketing Operations" in Note 2 to the Consolidated Financial Statements.



All hedge positions offset physical positions exposed to the cash market. None of the offsetting physical positions are included in the above table.

The fair value of over-the-counter instruments is estimated based on quoted market prices of comparable contracts.

Price changes were calculated by assuming an across-the-board ten percent adverse price change regardless of term or historical relationship between the contract price of an instrument and the underlying commodity price. In the event of an actual ten percent change in prompt month prices, the fair value of Calpine's derivative portfolio would typically change less than that shown in the table due to lower volatility in out-month prices.

**Impact of Recent Accounting Pronouncements**

In June 1999, the Financial Accounting Standards Board ("FASB") issued Statement of Financial Accounting Standards ("SFAS") No. 137, "Accounting for Derivative Instruments and Hedging Activities — Deferral of the Effective Date of FASB Statement No. 133 — an Amendment of FASB Statement No. 133." The Statement amends SFAS No. 133 to defer its effective date to all fiscal quarters of all fiscal years beginning after June 15, 2000. In June 2000, the FASB issued SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities — An Amendment of FASB Statement No. 133." Calpine formally adopted these accounting requirements on January 1, 2001. Calpine currently holds four classes of derivative instruments that will be impacted by the new pronouncements — interest rate swaps, foreign currency swaps, commodity financial instruments, and commodity contracts.

Upon adoption of SFAS No. 133, the fair values of derivative instruments designated as hedges will be recorded on the balance sheet as an asset or liability at their fair value. The difference between the carrying value of the derivative and its fair value at the date of adoption shall be recorded as a transition adjustment. In the case of the effective portion of a hedge, which previously addressed the variable cash flow exposure of a transaction, a transition adjustment will be recorded as a cumulative-effect-type adjustment to accumulated Other comprehensive income ("OCI"). In the case of the ineffective portion of a hedge, an adjustment will be calculated using the dollar offset method and charged to income or expense on the income statement as the effect of a change in accounting principle. The fair values of derivative instruments that are not designated as effective hedges and that do not meet the normal purchase or sale exception of SFAS No. 138 will be recorded on the balance sheet as an asset or liability at fair value and an adjustment will be charged to income or expense on the income statement as the effect of a change in accounting principle.

At the end of each quarter, the changes in fair values of derivative instruments designated as cash flow hedges will be recorded on the balance sheet as an asset or liability. In the case of the effective portion of a hedge, an adjustment will be recorded to OCI. In the case of the ineffective portion of a hedge, an adjustment will be calculated using the dollar offset method and charged to income or expense on the income statement. The changes in fair values of derivative instruments that are not designated as effective hedges and that do not meet the normal purchase or sale exception of SFAS No. 138 will be recorded on the balance sheet as an asset or liability and an offset will be charged to income or expense on the income statement.

At January 1, 2001, the FASB had not resolved Derivatives Implementation Group ("DIG") Issue 14-3, dealing with a proposed electric industry normal purchases and sales exception for capacity sales transactions. Calpine expects that the FASB will permit the use of this exception for capacity sales contracts that include all of the following characteristics:

- It is probable at inception and throughout the term of the individual contract that the contract — if exercised by the holder — will not settle net, as defined in SFAS No. 133, and will result in physical delivery.
- The electricity contract would not otherwise be considered an energy trading contract under the Emerging Issues Task Force Issue No. 98-10.
- The contract meets all other applicable criteria outlined in paragraph 10(b) of SFAS No. 133.

All capacity sales contracts and other commodity contracts currently held by Calpine meet the above criteria and are therefore subject to the FASB's final decision which is expected in early 2001. See Note 2 of the Notes to Consolidated Financial Statements for the financial statement effects if Calpine had adopted SFAS No. 133 on December 31, 2000.



**Exhibit VI.**

**Item 8.** ***Financial Statements and Supplementary Data***

**REPORT OF INDEPENDENT PUBLIC ACCOUNTANTS**

To The Board of Directors
and Stockholders of Calpine Corporation:

We have audited the accompanying consolidated balance sheets of Calpine Corporation (a Delaware corporation) and subsidiaries as of December 31, 2000 and 1999, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the three years in the period ended December 31, 2000. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits. We did not audit the financial statements of Encal Energy Ltd. ("Encal"), a company acquired on April 19, 2001 in a transaction accounted for as a pooling-of-interests, as discussed in Note 2. Such statements are included in the consolidated financial statements of Calpine Corporation and reflect total assets and total revenues of 5.7 percent and 10.4 percent, respectively, in 2000 and 9.3 percent and 13.8 percent, respectively, in 1999, and total revenues of 14.6 percent in 1998 of the related consolidated totals. These statements were audited by other auditors whose report has been furnished to us and our opinion, insofar as it relates to amounts included for Encal, is based solely upon the report of the other auditors.

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

In our opinion, based on our audits and the report of the other auditors, the financial statements referred to above present fairly,in all material respects, the financial position of Calpine Corporation and subsidiaries as of December 31, 2000 and 1999, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States.

ARTHUR ANDERSEN LLP

San Jose, California
April 19, 2001



**REPORT OF INDEPENDENT CHARTERED ACCOUNTANTS**

The Board of Directors of Encal Energy Ltd.

We have audited the consolidated balance sheets of Encal Energy Ltd. as of December 31, 2000, 1999 and 1998 and the related consolidated statements of earnings, changes in shareholders' equity, and cash flows for each of the three years in the three year period ended December 31, 2000. These financial statements are the responsibility of the company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

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

presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Encal Energy Ltd. at December 31, 2000, 1999 and 1998, and the consolidated results of its operations and its cash flows for each of the three years in the three year period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States.

ERNST AND YOUNG LLP

Calgary, Canada
February 16, 2001



**CALPINE CORPORATION AND SUBSIDIARIES**

**CONSOLIDATED BALANCE SHEETS**
**December 31, 2000 and 1999**
**(In thousands, except share and per share amounts)**

ASSETS

| | 2000 | 1999 |
|---|---|---|
| Current assets: | | |
| Cash and cash equivalents | $ 596,077 | $ 349,371 |
| Accounts receivable, net of allowance of $11,555 and $3,646 | 727,893 | 167,883 |
| Inventories | 44,456 | 21,807 |
| Prepaid expenses | 27,515 | 24,848 |
| Other current assets | 41,165 | 8,287 |
| Total current assets | 1,437,106 | 572,196 |
| Property, plant and equipment, net | 7,979,160 | 3,276,180 |
| Investments in power projects | 205,621 | 243,225 |
| Project development costs | 38,597 | 24,018 |
| Notes receivable | 217,927 | 23,548 |
| Restricted cash | 88,618 | 43,615 |
| Deferred financing costs | 112,049 | 49,599 |
| Other assets | 244,125 | 168,521 |
| Total assets | $10,323,203 | $4,400,902 |

LIABILITIES & STOCKHOLDERS' EQUITY

| | | |
|---|---|---|
| Current liabilities: | | |
| Notes payable and borrowings under lines of credit, current portion | $ 1,087 | $ 38,867 |
| Project financing, current portion | 58,486 | 8,603 |
| Capital lease obligation, current portion | 1,985 | — |
| Accounts payable | 843,641 | 130,966 |
| Income taxes payable | 63,409 | 8,835 |
| Accrued payroll and related expenses | 53,667 | 24,345 |
| Accrued interest payable | 77,878 | 38,897 |
| Other current liabilities | 149,080 | 73,250 |
| Total current liabilities | 1,249,233 | 323,763 |
| Notes payable and borrowings under lines of credit, net of current portion | 455,067 | 306,034 |

| | | |
|---|---|---|
| Project financing, net of current portion | 1,473,869 | 357,137 |
| Senior notes | 2,551,750 | 1,551,750 |
| Capital lease obligation, net of current portion | 208,876 | — |
| Deferred income taxes, net | 620,807 | 299,832 |
| Deferred lease incentive | 60,676 | 64,245 |
| Deferred revenue | 92,511 | 33,876 |
| Other liabilities | 30,529 | 31,758 |
| Total liabilities | 6,743,318 | 2,968,395 |
| Commitments and contingencies (see Note 18) | | |
| Company-obligated mandatorily redeemable convertible preferred securities of subsidiary trusts | 1,122,490 | 270,713 |
| Minority interests | 37,576 | 61,705 |
| Stockholders' equity: | | |
| Preferred stock, $.001 par value per share; authorized 10,000,000 shares; issued and outstanding one share in 2000 and none in 1999 | — | — |
| Common stock, $.001 par value per share; authorized 500,000,000 shares in 2000 and 400,000,000 in 1999; issued and outstanding 300,074,078 shares in 2000 and 268,381,864 shares in 1999 | 300 | 268 |
| Additional paid-in capital | 1,896,987 | 943,865 |
| Retained earnings | 547,895 | 175,293 |
| Accumulated other comprehensive loss | (25,363) | (19,337) |
| Total stockholders' equity | 2,419,819 | 1,100,089 |
| Total liabilities and stockholders' equity | $10,323,203 | $4,400,902 |

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



**CALPINE CORPORATION AND SUBSIDIARIES**

**CONSOLIDATED STATEMENTS OF OPERATIONS**
**For the Years Ended December 31, 2000, 1999 and 1998**
**(In thousands, except per share amounts)**

| | 2000 | 1999 | 1998 |
|---|---|---|---|
| Revenue: | | | |
| Electric generation and marketing revenue | $2,072,974 | $783,482 | $511,360 |
| Oil and gas production and marketing revenue | 444,462 | 155,983 | 101,921 |
| Income from unconsolidated investments in power projects | 24,639 | 36,593 | 25,240 |
| Other revenue | 5,026 | 7,426 | 12,125 |
| Total revenue | 2,547,101 | 983,484 | 650,646 |
| Cost of revenue: | | | |
| Electric generation and marketing expense | 587,187 | 155,067 | 91,928 |
| Oil and gas production and marketing expense | 197,773 | 65,438 | 48,554 |
| Fuel expense | 612,947 | 268,734 | 181,593 |
| Depreciation expense | 230,787 | 134,907 | 118,873 |
| Operating lease expense | 69,419 | 33,594 | 17,129 |
| Other expenses | 2,020 | 6,909 | 7,949 |

| | | | |
|---|---|---|---|
| Total cost of revenue | 1,700,133 | 664,649 | 466,026 |
| Gross profit | 846,968 | 318,835 | 184,620 |
| Project development expense | 27,556 | 10,712 | 7,165 |
| General and administrative expense | 102,551 | 55,667 | 30,024 |
| Income from operations | 716,861 | 252,456 | 147,431 |
| Interest expense | 74,683 | 103,248 | 95,732 |
| Distributions on trust preferred securities | 44,210 | 2,565 | — |
| Interest income | (39,901) | (24,106) | (12,348) |
| Minority interest, net | 2,684 | — | — |
| Other income | (3,461) | (5,109) | 3,706 |
| Income before provision for income taxes | 638,646 | 175,858 | 60,341 |
| Provision for income taxes | 264,809 | 68,058 | 21,183 |
| Income before extraordinary charge | 373,837 | 107,800 | 39,158 |
| Extraordinary charge net of tax benefit of $796, $793 and $441 | 1,235 | 1,150 | 641 |
| Net income | $ 372,602 | $106,650 | $ 38,517 |
| Basic earnings per common share: | | | |
| Weighted average shares of common stock outstanding | 281,070 | 225,375 | 176,725 |
| Income before extraordinary charge | $ 1.33 | $ 0.48 | $ 0.22 |
| Extraordinary charge | $ — | $ (0.01) | $ — |
| Net income | $ 1.33 | $ 0.47 | $ 0.22 |
| Diluted earnings per common share: | | | |
| Weighted average shares of common stock outstanding before dilutive effect of certain trust preferred securities | 297,507 | 238,706 | 185,067 |
| Income before extraordinary charge and dilutive effect of certain trust preferred securities | $ 1.26 | $ 0.45 | $ 0.21 |
| Dilutive effect of certain trust preferred securities(1) | $ (0.06) | $ — | $ — |
| Income before extraordinary charge | $ 1.20 | $ 0.45 | $ 0.21 |
| Extraordinary charge | $ (0.01) | $ — | $ — |
| Net income | $ 1.19 | $ 0.45 | $ 0.21 |

(1) Includes the effect of the assumed conversion of certain trust preferred securities. For the twelve months ended December 31, 2000, the assumed conversion calculation adds 31,746 shares of common stock and $20,841 to the net income results, representing the after tax distribution expense on certain trust preferred securities avoided upon conversion.

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



**CALPINE CORPORATION AND SUBSIDIARIES**

**CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY**
**For the Years Ended December 31, 2000, 1999 and 1998**
**(In thousands, except share amounts)**

| | Common Stock | Additional Paid-in Capital | Retained Earnings | Accumulated Other Comprehensive Loss | Total Stockholders' Equity | Comprehensive Income (Loss) |
|---|---|---|---|---|---|---|
| Balance, December 31, 1997 | $176 | $ 351,917 | $ 30,126 | $(11,562) | $ 370,657 | |

| | | | | | | |
|---|---|---|---|---|---|---|
| Issuance of 1,023,634 shares of common stock, net of issuance costs | 1 | 4,410 | — | — | 4,411 | |
| Tax benefit from stock options exercised and other | — | 222 | — | — | 222 | |
| Comprehensive income: | | | | | | |
| Net income | — | — | 38,517 | — | 38,517 | $ 38,517 |
| Other comprehensive income | — | — | — | (11,097) | (11,097) | (11,097) |
| Total comprehensive income | — | — | — | — | — | $ 27,420 |
| Balance, December 31, 1998 | 177 | 356,549 | 68,643 | (22,659) | 402,710 | |
| Issuance of 91,228,316 shares of common stock, net of issuance costs | 91 | 581,339 | — | — | 581,430 | |
| Tax benefit from stock options exercised and other | — | 5,977 | — | — | 5,977 | |
| Comprehensive income: | | | | | | |
| Net income | — | — | 106,650 | — | 106,650 | $106,650 |
| Other comprehensive income | — | — | — | 3,322 | 3,322 | 3,322 |
| Total comprehensive income | — | — | — | — | — | $109,972 |
| Balance, December 31, 1999 | 268 | 943,865 | 175,293 | (19,337) | 1,100,089 | |
| Issuance of 28,190,682 shares of common stock, net of issuance costs | 28 | 785,900 | — | — | 785,928 | |
| Issuance of 3,501,532 shares of common stock for acquisitions | 4 | 120,591 | — | — | 120,595 | |
| Tax benefit from stock options exercised and other | — | 46,631 | — | — | 46,631 | |
| Comprehensive income: | | | | | | |
| Net income | — | — | 372,602 | — | 372,602 | $372,602 |
| Other comprehensive income | — | — | — | (6,026) | (6,026) | (6,026) |
| Total comprehensive income | — | — | — | — | — | $366,576 |
| Balance, December 31, 2000 | $300 | $1,896,987 | $547,895 | $(25,363) | $2,419,819 | |

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



**CALPINE CORPORATION AND SUBSIDIARIES**

**CONSOLIDATED STATEMENTS OF CASH FLOWS**
**For the Years Ended December 31, 2000, 1999 and 1998**
**(In thousands)**

| | 2000 | 1999 | 1998 |
|---|---|---|---|
| Cash flows from operating activities: | | | |
| Net income | $ 372,602 | $ 106,650 | $ 38,517 |
| Adjustments to reconcile net income to net cash provided by operating activities: | | | |

| | | | |
|---|---|---|---|
| Depreciation and amortization | 218,118 | 139,305 | 119,170 |
| Deferred income taxes, net | 108,481 | 54,029 | 7,683 |
| Income from unconsolidated investments in power projects | (24,639) | (36,593) | (25,240) |
| Distributions from unconsolidated power projects | 29,979 | 43,318 | 27,717 |
| (Gain) loss on sale of assets | (1,051) | (561) | 870 |
| Change in operating assets and liabilities, net of effects of acquisitions: | | | |
| Accounts receivable | (515,717) | (38,191) | 2,202 |
| Notes receivable | (46,066) | (13,919) | — |
| Other current assets | (27,728) | (6,924) | 21,125 |
| Other assets | (43,654) | (9,153) | (28,968) |
| Accounts payable and accrued expenses | 684,970 | 79,817 | 28,448 |
| Other liabilities | 47,255 | (3,417) | 8,185 |
| Net cash provided by operating activities | 802,550 | 314,361 | 199,709 |
| Cash flows from investing activities: | | | |
| Purchases of property, plant and equipment | (3,183,314) | (1,074,803) | (222,943) |
| Disposals of property, plant and equipment | 17,321 | 19,063 | 33,073 |
| Proceeds from sale and leaseback of plant | 642,205 | 71,236 | 559 |
| Acquisitions, net of cash acquired | (840,928) | (540,587) | (305,263) |
| Advances to joint ventures | (141,106) | (48,066) | (2,952) |
| Decrease (increase) in notes receivable | (184,535) | 1,270 | 18,967 |
| Maturities of collateral securities | 6,445 | 1,850 | 6,030 |
| Project development costs | (53,129) | (30,635) | (17,435) |
| Decrease (increase) in restricted cash | (15,616) | 1,216 | 1,130 |
| Net cash used in investing activities | (3,752,657) | (1,599,456) | (488,834) |
| Cash flows from financing activities: | | | |
| Borrowings from project financing | 1,183,603 | 155,760 | 57,874 |
| Repayments of project financing | (580,111) | (123,386) | (162,145) |
| Proceeds from notes payable and borrowings under lines of credit | 1,107,267 | 219,183 | 50,400 |
| Repayments of notes payable and borrowings under lines of credit | (1,117,946) | (129,721) | — |
| Proceeds from issuance of senior notes | 1,000,000 | 600,000 | 400,000 |
| Repurchase of senior notes | — | — | (8,250) |
| Proceeds from Company-obligated mandatorily convertible preferred securities of a subsidiary trust | 877,500 | 276,000 | — |
| Proceeds from equity offerings, net of issuance costs | 773,249 | 597,368 | — |
| Proceeds from issuance of common stock | 14,767 | 6,192 | 4,411 |
| Write-off of deferred financing costs | 2,031 | 1,943 | — |
| Financing costs | (58,942) | (65,405) | (5,146) |
| Other | (4,605) | — | — |
| Net cash provided by financing activities | 3,196,813 | 1,537,934 | 337,144 |
| Net increase in cash and cash equivalents | 246,706 | 252,839 | 48,019 |
| Cash and cash equivalents, beginning of year | 349,371 | 96,532 | 48,513 |
| Cash and cash equivalents, end of year | $ 596,077 | $ 349,371 | $ 96,532 |
| Cash paid during the year for: | | | |
| Interest | $ 227,725 | $ 126,268 | $ 78,009 |
| Income taxes | $ 144,406 | $ 17,066 | $ 3,211 |

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

## 1. Organization and Operations of the Company

Calpine Corporation ("Calpine"), a Delaware corporation, and subsidiaries (collectively, "the Company") is engaged in the generation of electricity in the United States and Canada. The Company is involved in the development, acquisition, ownership and operation of power generation facilities and the sale of electricity and its by-product, thermal energy, primarily in the form of steam. The Company has ownership interests in and operates gas-fired power generation and cogeneration facilities, gas fields, gathering systems and gas pipelines, geothermal steam fields and geothermal power generation facilities in the United States and Canada. Each of the generation facilities produces and markets electricity for sale to utilities and other third party purchasers. Thermal energy produced by the gas-fired cogeneration facilities is primarily sold to governmental and industrial users. Gas produced and not physically delivered to the Company's generating plants is sold to third parties.

## 2. Summary of Significant Accounting Policies

*Principles of Consolidation* — The accompanying consolidated financial statements include accounts of the Company. Wholly owned and majority-owned subsidiaries are consolidated. Less-than-majority-owned subsidiaries and subsidiaries for which control is deemed to be temporary, are accounted for using the equity method. In the case of the Company's interest in the Lost Pines I Energy Center, the proportionate consolidation method is used. For equity method investments, the Company's share of income is calculated according to the Company's equity ownership or according to the terms of the appropriate partnership agreement (see Note 6). All significant intercompany accounts and transactions are eliminated in consolidation. Prior to the Company's acquisition of Unocal's interest in its Geysers geothermal properties on March 19, 1999, the Company used the proportionate consolidation method to account for Thermal Power Company's 25% ownership in jointly owned geothermal properties.

On April 19, 2001, Calpine acquired 100% of the outstanding shares and interests of Encal Energy Ltd. ("Encal"). The merger was accounted for as a pooling-of-interests and the consolidated financial statements have been prepared to give retroactive effect to the merger. Generally accepted accounting principles prescribe recording a business combination accounted for by the pooling-of-interests method as of the date the combination is consummated. These consolidated financial statements do not extend through the date of consummation; however, they will become the historical consolidated financial statements of the Company after financial statements covering the date of consummation have been issued.

Encal operated under the same fiscal year end as Calpine, and accordingly, Encal's balance sheets, as of December 31, 2000 and 1999, and the statements of operations, shareholders' equity and cash flows for each of the three fiscal years in the period ended December 31, 2000 have been combined with the Company's consolidated financial statements. Encal is a Calgary, Alberta-based natural gas and petroleum exploration and development company. As a result of the merger, the Company issued approximately 16.6 million common shares for all of the outstanding Encal capital stock and options.





The results of operations previously reported by the separate companies and the combined amounts presented in the consolidated financial statements are summarized below.

| | Years Ended December 31, | | |
|---|---|---|---|
| | 2000 | 1999 | 1998 |
| | (in thousands) | | |
| Revenues: | | | |
| Calpine | $2,282,793 | $ 847,735 | $555,948 |
| Encal | 264,308 | 135,749 | 94,698 |

| | | | |
|---|---|---|---|
| Combined revenues | $2,547,101 | $ 983,484 | $650,646 |
| Net Income: | | | |
| Calpine | $ 323,452 | $ 95,093 | $ 45,678 |
| Encal | 49,150 | 11,557 | (7,161) |
| Combined net income | $ 372,602 | $ 106,650 | $ 38,517 |
| Stockholders' Equity: | | | |
| Calpine | $2,236,774 | $ 964,632 | $286,966 |
| Encal | 183,045 | 135,457 | 115,744 |
| Combined stockholders' equity | $2,419,819 | $1,100,089 | $402,710 |

*Use of Estimates in Preparation of Financial Statements* — The preparation of financial statements in conformity with generally accepted accounting principles in the United States requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expense during the reporting period. Actual results could differ from those estimates. The most significant estimates with regard to these financial statements relate to future development costs, useful lives of the generation facilities, and depletion, depreciation and impairment of natural gas and petroleum property and equipment.

*Foreign Currency Translation* — Assets and liabilities of non-U.S. subsidiaries that operate in a local currency environment are translated to U.S. dollars at exchange rates in effect at the balance sheet date with the resulting translation adjustments recorded in other comprehensive income. Income and expense accounts are translated at average exchange rates during the year.

*Fair Value of Financial Instruments* — The carrying value of accounts receivable, marketable securities, accounts and other payables approximate their respective fair values due to their short maturities. See Note 9 for disclosures regarding the fair value of the senior notes.

*Cash and Cash Equivalents* — The Company considers all highly liquid investments with an original maturity of three months or less to be cash equivalents. The carrying amount of these instruments approximates fair value because of their short maturity.

*Inventories* — Operating supplies are valued at the lower of cost or market. Cost for large replacement parts estimated to be used within one year is determined using the specific identification method. For the remaining supplies and spare parts, cost is generally determined using the weighted average cost method.

*Project Development Costs* — The Company capitalizes project development costs once it is determined that it is probable that such costs will be realized through the ultimate construction of a power plant. These costs include professional services, salaries, permits and other costs directly related to the development of a new project. Outside services and other third party costs are capitalized for acquisition projects. Upon commencement of construction, these costs are transferred to construction in progress in property, plant and equipment, net. Upon the start-up of plant operations, these costs are generally transferred to property, plant





and equipment and amortized over the estimated useful life of the project. Capitalized project costs are charged to expense if the Company determines that the project is impaired.

*Restricted Cash* — The Company is required to maintain cash balances that are restricted by provisions of certain of its debt agreements, lease agreements and by regulatory agencies. The Company's debt agreements specify restrictions based on debt service payments and drilling costs. Regulatory agencies require cash to be restricted to ensure that funds will be available to restore property to its original condition. Restricted cash is invested in accounts earning market rates; therefore, the carrying value approximates fair value. Such cash is excluded from cash and cash equivalents for the purposes of the consolidated statements of cash flows.

*Deferred Financing Costs* — The deferred financing costs related to the Company's senior notes are amortized over the life of the related debt, ranging from 5 to 10 years, using the effective interest rate method (See Note 9). The deferred financing costs associated with the two Calpine Construction Finance Company facilities are amortized over the 4-year facility lives using the straight-line method (See Note 8). Costs incurred in connection with obtaining other financing are deferred and amortized over the remaining life of the related debt, generally ranging from 1 to 20 years.

*Long-Lived Assets* — In accordance with Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standards ("SFAS") No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed of," the Company evaluates the impairment of long-lived assets, including goodwill, based on the projection of undiscounted cash flows whenever events or changes in circumstances indicate that the carrying amounts of such assets may not be recoverable. In the event such cash flows are not expected to be sufficient to recover the recorded value of the assets, the assets are written down to their estimated fair values.

*Major Maintenance* — For major gas turbine generator refurbishments, the Company defers the costs and amortizes them over 3 to 6 years. Geothermal steam turbine refurbishments are expensed as incurred. These two methods are the Company's primary accounting methods for major maintenance. Additionally, the Company accrues in advance for certain non-annual planned maintenance.

*Trust Preferred Securities* — During 1999 and 2000, the Company issued trust preferred securities, which are treated as a minority interest in the balance sheet and reflected as "Company-obligated mandatorily redeemable convertible preferred securities of subsidiary trusts." The distributions are reflected on the income statement as "distributions on trust preferred securities." Financing costs related to these issuances are netted with the principal amounts and are accreted over the securities' 30-year maturity by the straight-line method (See Note 11).

*Revenue Recognition* — The Company is primarily an electric generation company, operating a portfolio of mostly wholly owned plants but also some plants in which its ownership interest is 50% or less and which are accounted for under the equity method. In conjunction with its electric generation business, the Company also produces, as a by-product, thermal energy for sale to customers, principally steam hosts at its cogeneration sites. In addition, the Company acquires and produces natural gas for its own consumption and sells the balance and small amounts of oil to third parties. To protect and enhance the profit potential of its electric generation plants, the Company, through its subsidiary, Calpine Energy Services, LP ("CES"), enters into electric and gas hedging, balancing and related transactions in which purchased electricity and gas is resold to third parties. CES acts as a principal, takes title to the commodities purchased for resale, and assumes the risks and rewards of ownership. Therefore, in accordance with Staff Accounting Bulletin No. 101, "Revenue Recognition in Financial Statements" and the Emerging Issues Task Force ("EITF") Issue No. 99-19, "Reporting Revenue Gross as a Principal Versus Net as an Agent," CES recognizes revenue on a gross basis, except in the case of financial swap transactions, in which case the net gain or loss from the hedging





instrument is recorded in income against the underlying hedged item when the effects of the hedged item are recognized. Hedged items typically include sales to third parties of natural gas produced, purchases of natural gas to fuel power plants, and sales of generated electricity. Finally, the Company, through Power Systems Mfg., LLC ("PSM"), designs and manufactures spare parts for gas turbines. The Company also generates small amounts of revenue by occasionally loaning funds to power projects and by providing operation and maintenance ("O&M") services to unconsolidated power plants. Further details of the Company's revenue recognition policy for each type of revenue transaction are provided below:

*Electric Generation and Marketing Revenue* — This includes electricity and steam sales, gains and losses from electric power derivatives and sales of purchased power. The Company actively manages the revenue stream for its portfolio of electricity-generating facilities. As the Company actively manages the revenue stream for its portfolio of electric generation facilities, it is appropriate to review the Company's financial performance using all electric generation and marketing revenue.

*Oil and Gas Production and Marketing Revenue* — This includes sales to third parties of gas, oil and related products that are produced by the Company's Calpine Natural Gas and Calpine Canada Natural Gas subsidiaries and also sales of purchased gas.

*Income from Unconsolidated Investments in Power Projects* — The Company uses the equity method to recognize as revenue its pro rata share of the net income or loss of the unconsolidated investment until such time, if applicable, the Company's investment is reduced to zero, at which time equity income is generally recognized only upon receipt of cash distributions from the investee.

*Other Revenue* — This includes O&M contract revenue, interest income on loans to power projects, PSM revenue from sales to third parties and miscellaneous revenue.

*Concentrations of Credit Risk* — Financial instruments which potentially subject the Company to concentrations of credit risk consist primarily of cash, accounts receivable and notes receivable. The Company's cash accounts are generally held in FDIC insured banks. The

Company's accounts and notes receivable are concentrated within entities engaged in the energy industry, mainly within the United States (see Note 15). The Company generally does not require collateral for accounts receivable.

*Derivative Financial Instruments* — The Company engages in activities to manage risks associated with changes in interest rates. The Company has entered into swap agreements to reduce exposure to interest rate fluctuations. The instruments' cash flows mirror those of the underlying exposure. Unrealized gains and losses relating to the instruments are being deferred over the lives of the contracts. The premiums paid on the instruments, as measured at inception, are being amortized over their respective lives as components of interest expense. Any gains or losses realized upon the early termination of these instruments are being amortized over the respective lives of the underlying transaction or recognized immediately if the transaction is terminated earlier than initially anticipated. Gains and losses on any instruments not meeting the above criteria would be recognized in income in the current period. Subsequent gains or losses on the related financial instrument are recognized in income in each period until the instrument matures, is terminated or is sold. Cash flows from swap contracts accounted for as hedges are classified in the same category as the item being hedged.

*Energy Marketing Operations* — The Company, through its wholly owned subsidiary CES, markets energy services to utilities, wholesalers, and end users. CES provides these services by entering into contracts to purchase or supply electricity and natural gas, primarily, at specified delivery points and specified future dates. In some cases, CES utilizes financial instruments to manage its exposure to electricity and natural gas price fluctuations, and to a lesser degree, price fluctuations of oil and refined products. On December 31, 2000, CES held swap contracts with several entities in order to hedge these price fluctuations.





At December 31, 2000, the Company had positions with a net fair value of $104.4 million to protect the Company against the risks of fluctuating market prices. The Company is accounting for these positions under the requirements of SFAS No. 80, "Accounting For Futures Contracts", until SFAS No. 80 is superseded on January 31, 2001 by the Company's adoption of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities." The Company actively manages its positions in accordance with its risk management policy. Net gains and losses related to commodity swap contracts are recognized when realized. The Company's credit risk associated with power and fuel contracts results from the risk-of-loss on non-performance by counter parties. The Company reviews and assesses counter party risk to limit any material impact to its financial position and results of operations. The Company does not anticipate non-performance by the counterparties.

*New Accounting Pronouncements* — In June 1999, the FASB issued SFAS No. 137, "Accounting for Derivative Instruments and Hedging Activities — Deferral of the Effective Date of FASB Statement No. 133 — an Amendment of FASB Statement No. 133." The statement amends SFAS No. 133 to defer its effective date to all fiscal quarters of all fiscal years beginning after June 15, 2000. In June 2000, the FASB issued SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities — An Amendment of FASB Statement No. 133." The Company formally adopted these accounting requirements on January 1, 2001. The Company currently holds four classes of derivative instruments that will be impacted by the new pronouncements — interest rate swaps, foreign currency swaps, commodity financial instruments, and commodity contracts.

Upon adoption of SFAS No. 133, the fair values of derivative instruments designated as hedges will be recorded on the balance sheet as an asset or liability at their fair value. The difference between the carrying value of the derivative and its fair value at the date of adoption shall be recorded as a transition adjustment. In the case of the effective portion of a hedge, which previously addressed the variable cash flow exposure of a transaction, a transition adjustment will be recorded as a cumulative-effect-type adjustment to accumulated other comprehensive income ("OCI"). In the case of the ineffective portion of a hedge, an adjustment will be calculated using the dollar offset method and charged to income or expense on the statement of operations as the effect of a change in accounting principle. The fair values of derivative instruments that are not designated as effective hedges and that do not meet the normal purchase or sale exception of SFAS No. 138 will be recorded on the balance sheet as an asset or liability at fair value and an adjustment will be charged to income or expense on the statement of operations as the effect of a change in accounting principle.

At the end of each quarter, the changes in fair values of derivative instruments designated as cash flow hedges will be recorded on the balance sheet as an asset or liability. In the case of the effective portion of a hedge, an adjustment will be recorded to OCI. In the case of the ineffective portion of a hedge, an adjustment will be calculated using the dollar offset method and charged to income or expense on the statement of operations. The changes in fair values of derivative instruments that are not designated as effective hedges and that do not meet the normal purchase or sale exception of SFAS No. 138 will be recorded on the balance sheet as an asset or liability and an offset will be charged to income or expense on the statement of operations.

At January 1, 2001, the FASB had not resolved Derivatives Implementation Group ("DIG") Issue 14-3, dealing with a proposed electric industry normal purchases and sales exception for capacity sales transactions. The Company expects that the FASB will permit the use of this exception for capacity sales contracts that include all of the following characteristics:

- It is probable at inception and throughout the term of the individual contract that the contract — if exercised by the holder — will not settle net, as defined in SFAS No. 133, and will result in physical delivery.

- The electricity contract would not otherwise be considered an energy trading contract under the EITF Issue No. 98-10.





- The contract meets all other applicable criteria outlined in paragraph 10(b) of SFAS No. 133.

All capacity sales contracts and other commodity contracts currently held by the Company meet the above criteria and are therefore subject to the FASB's final decision which is expected in early 2001. The table below reflects the amounts (in thousands), by derivative instrument, including capacity sales contracts, that would be recorded as assets, liabilities, expense, and OCI if the Company adopted SFAS No. 133 on December 31, 2000.

| | Interest Rate Swaps | Commodity Derivative Instruments | Total Derivative Instruments |
|---|---|---|---|
| Current derivative asset | $ — | $712,143 | $712,143 |
| Long-term derivative asset | 868 | 122,182 | 123,050 |
| Total assets | $ 868 | $834,325 | $835,193 |
| Current derivative liability | 502 | 676,135 | 676,637 |
| Long-term derivative liability | 25,510 | 69,588 | 95,098 |
| Total liabilities | $ 26,012 | $745,723 | $771,735 |
| Total comprehensive income (loss) | (25,144) | 86,897 | 61,753 |
| Income tax benefit (expense) | 9,856 | (34,063) | (24,207) |
| Net comprehensive income (loss) | $(15,288) | $ 52,834 | 37,546 |
| Cumulative effect of a change in accounting principle (net of income tax expense) | $ — | $ 1,036 | $ 1,036 |

*Reclassifications* — Certain prior years' amounts in the Consolidated Financial Statements have been reclassified to conform to the 2000 presentation.

**3. Property, Plant and Equipment, Net, and Capitalized Interest**

Property, plant and equipment, net, are stated at cost less accumulated depreciation and amortization.

The Company capitalizes costs incurred in connection with the development of geothermal properties, including costs of drilling wells and overhead directly related to development activities, together with the costs of production equipment, the related facilities and the operating power plants. Proceeds from the sale of geothermal properties are applied against capitalized costs, with no gain or loss recognized.

Geothermal costs, including an estimate of future costs to be incurred, costs to optimize the productivity of the assets, and the estimated costs to dismantle, are amortized by the units of production method based on the estimated total productive output over the estimated useful lives of the related steam fields. Depreciation of the buildings and roads is computed using the straight-line method over their estimated useful lives. It is reasonably possible that the estimate of useful lives, total units of production or total capital costs to be amortized using the units of production method could differ materially in the near term from the amounts assumed in arriving at current depreciation expense. These estimates are affected by such factors as the ability of the Company to continue selling electricity to customers at estimated prices, changes in prices of alternative sources of energy such as hydro-generation and gas, and changes in the regulatory environment.

Gas-fired power production facilities include cogeneration plants and related equipment and are stated at cost. Depreciation is recorded utilizing the straight-line method over the estimated original useful life of up to 38 years, exclusive of the estimated salvage value, typically 10%. The value of the above-market or below-market pricing provided in power sales agreements and fuel supply contracts acquired is recorded in property, plant and equipment, net and is amortized over the above-market or below-market pricing period in the power sales agreement or fuel supply contract with lives ranging from month-to-month to 28 years. When assets are





disposed of, the cost and related accumulated depreciation are removed from the accounts, and the resulting gains or losses are included in results of operations.

The Company follows the successful efforts method of accounting for oil and natural gas operations. Under the successful efforts method, capitalized costs relating to proved properties are amortized using the units-of-production method based on estimated proven reserves. The cost of unsuccessful exploration wells is charged to operations.

Successful exploratory wells and development costs are depleted over gross proved developed reserves while acquired resource properties with proved reserves are depleted over gross proved reserves using the unit of production method. For purposes of these calculations, production and reserves of natural gas are converted to barrels on an energy equivalent basis. Acquisition costs of probable reserves are not depleted or amortized while under active evaluation for commercial reserves. Costs are transferred to depletable costs as proved reserves are recognized. Producing properties and significant unproved properties are assessed annually, or as economic events dictate, for potential impairment.

As of December 31, 2000 and 1999, the components of property, plant and equipment, net are as follows (in thousands):

| | 2000 | 1999 |
|---|---|---|
| Geothermal properties | $ 334,585 | $ 366,059 |
| Oil and gas properties | 1,441,175 | 800,590 |
| Buildings, machinery and equipment | 1,951,250 | 1,226,428 |
| Power sales agreements | 162,086 | 145,957 |
| Gas contracts | 129,999 | 122,593 |
| Other | 145,877 | 78,735 |
| | 4,164,972 | 2,740,362 |
| Less: accumulated depreciation and amortization | (614,816) | (456,096) |
| | 3,550,156 | 2,284,266 |
| Land | 12,578 | 3,419 |
| Construction in progress | 4,416,426 | 988,495 |
| Property, plant and equipment, net | $7,979,160 | $3,276,180 |

Construction in progress is primarily attributable to gas-fired power projects under construction. Upon commencement of plant operation, these costs are transferred to buildings, machinery and equipment.

*Capitalized Interest* — The Company capitalizes interest on capital invested in projects during the advanced stages of development and the construction period in accordance with SFAS No. 34, “Capitalization of Interest Cost,” as amended by SFAS No. 58, “Capitalization of Interest Cost in Financial Statements That Include Investments Accounted for by the Equity Method (an Amendment of FASB Statement No. 34).” For the years ended December 31, 2000 and 1999, the Company recorded net interest expense of $74.7 million and $103.2 million, respectively, after capitalizing $171.0 million and $39.7 million, respectively, of interest on general corporate funds used for construction, and after $36.0 million and $7.6 million, respectively, of interest capitalized on funds borrowed for specific construction projects in 2000 and 1999, respectively. Upon commencement of plant operation, capitalized interest, as a component of the total cost of the plant, is amortized over the estimated useful life of the plant. The increase in the amount of interest capitalized during the year ended December 31, 2000 reflects the significant increase in the Company’s power plant construction program.

**4. Acquisitions**

The following acquisitions were consummated during the year ended December 31, 1999. All business combinations made during 1999 were accounted for as purchases.

*Unocal Transaction*

On March 19, 1999, the Company acquired Unocal Corporation's Geysers geothermal steam fields in northern California for approximately $102.2 million. The steam fields fuel the Company's power plants located at the Geysers, California. See "PG&E Transactions" below.

*PG&E Transactions*

On May 7, 1999, the Company completed the acquisition of 12 Sonoma County and 2 Lake County power plants, located at the Geysers, California from PG&E for approximately $212.8 million. These plants have a combined capacity of approximately 657 megawatts of electricity.

*Aidlin Transaction*

On August 31, 1999, the Company completed the acquisition of an additional 50% interest in the Aidlin Power Plant from Edison Mission Energy and General Electric Capital Corporation for a total purchase price of $7.2 million. The Company previously owned a 5% interest in the project.

*Calistoga and Silverado Transactions*

On October 19, 1999, the Company purchased the Calistoga Power Plant, the Silverado steam fields and related assets from FPL Energy and Caithness Corporation for $77.9 million.

*Calpine Natural Gas Company Transaction*

On October 1, 1999, the Company completed the acquisition of Sheridan Energy Inc. ("Sheridan"), a natural gas exploration and production company, through a $38.8 million cash tender offer. The Company purchased the outstanding shares of Sheridan's common stock for $5.50 per share. In addition, the Company redeemed $11.9 million of outstanding preferred stock of Sheridan. Sheridan's oil and gas properties are primarily located in northern California and the Gulf Coast region. Previously, the Company had acquired a 20% interest in Sheridan California Energy, Inc. from Sheridan for $14.9 million. As a result of the two aforementioned acquisitions, the Company now owns all of the assets of Sheridan and included the results in its Consolidated Financial Statements at December 31, 1999. The Company subsequently renamed Sheridan as Calpine Natural Gas Company ("CNGC"). The Company accounted for its investment in Sheridan under the equity method until October 1, 1999. From October 1, 1999 through December 31, 1999, the results of CNGC's operations are consolidated.

*Calpine Cogeneration Corporation Transaction*

On December 17, 1999, the Company completed the acquisition of 80% of the common stock of Cogeneration Corporation of America, Inc. ("CGCA") for approximately $137.3 million with the remaining 20% being owned by NRG Energy Inc., a subsidiary of Xcel Energy, Inc. As a result of this acquisition the Company received an ownership interest in six natural gas-fired facilities totaling approximately 461 megawatts of capacity and has assumed operations of five of the plants. The Company subsequently renamed CGCA as Calpine Cogeneration Corporation ("CCC").

*Vintage Transaction*

On December 31, 1999, but effective as of November 1, 1999, the Company acquired proven natural gas reserves and certain leasehold acreage from Vintage Petroleum, Inc. ("Vintage") of Tulsa, Oklahoma for approximately $71.5 million. The Company added the remaining 58.8% working interest in the Rio Vista Gas Unit and certain development acreage to its northern California gas portfolio. This new production utilizes the Company's Sacramento Basin gas pipeline system. The Company initially acquired a 40.7% working interest in the Rio Vista Gas Unit in October 1999 through its Sheridan acquisition.

The following acquisitions were consummated during the year ended December 31, 2000. All business combinations made during 2000 were accounted for as purchases.

*Western Transaction*

On February 4, 2000, the Company acquired 100% of the stock of Western Gas Resources California ("Western") from Western Gas Resources, Inc. for $14.9 million. Western's assets include the 130-mile Steelhead natural gas pipeline and the remaining interest in the Sacramento River Gas System natural gas pipeline, now 100% owned by Calpine.

*Hidalgo Transaction*

On March 30, 2000, the Company purchased a 78.5% interest in the 502-megawatt Hidalgo Energy Center which was under construction in Edinburg, Texas, from Duke Energy North America for $235 million. The purchase included a cash payment of $134 million and the assumption of a $101 million capital lease obligation. The Hidalgo Energy Center sells power into the Electric Reliability Council of Texas' ("ERCOT") wholesale market. Construction of the facility began in February 1999, and commercial operation was achieved in June 2000.

*KIAC and Stony Brook Transaction*

On May 31, 2000, Calpine acquired the remaining 50% interests in the 105-megawatt Kennedy International Airport Power Plant ("KIAC") in Queens, New York and the 40-megawatt Stony Brook Power Plant located at the State University of New York at Stony Brook on Long Island from Statoil Energy, Inc. The Company paid approximately $71 million in cash and assumed a capital lease obligation relating to the Stony Brook Power Plant. The Company initially acquired a 50% interest in both facilities in December 1997.

*Freestone Transaction*

On June 15, 2000, the Company announced that it had acquired the Freestone Energy Center from Energy Corporation. Freestone is a 1,052-megawatt natural gas-fired energy center under development in Freestone County, Texas. The technologically advanced energy center is currently under construction, with a two-phased commercial start-up beginning in the summer of 2002. The Company paid approximately $61.0 million in cash and assumed certain liabilities. This represented payment for the land and development rights for the Freestone Energy Center, previous progress payments made for four General Electric gas turbines, two steam turbines and related equipment, and development expenditures incurred to date.

*Auburndale Transaction*

On June 30, 2000, the Company acquired from Edison Mission Energy the remaining 50% ownership interest in a 153-megawatt natural gas-fired, combined-cycle cogeneration facility located in Auburndale, Fla. The Company paid approximately $22.0 million in cash and assumed certain liabilities, including project level debt. Related to the project level debt was the assumption of an interest rate swap agreement with a notional





amount of $121.5 million at December 31, 2000, which effectively converts the project level debt's floating rate to a fixed rate of 6.52% per annum. The Company acquired an initial 50% ownership interest in the Auburndale Power Plant in October 1997.

*Natural Gas Reserves Transactions*

On July 5, 2000, the Company completed three acquisitions of natural gas reserves for $206.5 million, including the acquisition of Calgary-based Quintana Minerals Canada Corp. ("QMCC"), three fields in the Gulf of Mexico and natural gas assets in the Piceance Basin, Colorado and onshore Gulf Coast.

*Oneta Transaction*

On July 20, 2000, the Company completed the acquisition of the 1,138-megawatt natural gas-fired Oneta Energy Center, under development in Coseta, Oklahoma, from Panda Energy International, Inc.

*Agnews Transaction*

On August 16, 2000, the Company acquired the remaining 80% interest in the Agnews Power Plant, a 29-megawatt natural gas-fired, combined-cycle facility located in San Jose, California from GATX Capital Corporation for a total purchase price of $4.9 million. The Company first acquired a 20% equity interest in the Agnews Power Plant in 1990.

*Aidlin Transaction*

On August 31, 2000, the Company acquired the remaining 45% equity interest in the Aidlin Power Plant from an affiliate of Sumitomo Corporation for a total purchase price of $6.4 million. The Company initially acquired a 5% equity interest in the Aidlin Power Plant in 1989, representing Calpine's first megawatt of generation. That interest was increased to 55% with the acquisition of two other partners' interests in 1999. Located in The Geysers region of northern California, Aidlin is a 20-megawatt power plant.

*SkyGen Energy Transaction*

On October 12, 2000, the Company completed the acquisition of Northbrook, Illinois-based SkyGen Energy LLC ("SkyGen") from Michael Polsky and Wisvest Corporation ("Wisvest"), an affiliate of Wisconsin Energy Corp., for a total purchase price of $359.1 million. The purchase price included cash payments of $294.2 million and 2,117,742 shares of Calpine common stock (which were valued in the aggregate at $64.9 million at signing of the letter of intent).

*TriGas Transaction*

On November 15, 2000, the Company acquired TriGas Exploration Inc. ("TriGas"), the Calgary-based oil and gas company, for a total purchase price of $101.1 million. The purchase price included cash payments of $79.6 million, as well as assumed net indebtedness of $21.5 million. The acquisition provided Calpine with natural gas reserves to fuel its proposed Calgary Energy Centre, and a 26.6% working interest in the East Crossfield Gas Plant, extensive pipelines and gathering systems and a significant undeveloped land base with development potential.

*PSM Transaction*

On December 13, 2000, the Company completed the acquisition of Boca Raton, Florida-based PSM for a total purchase price of $16.3 million. The purchase price included cash payments of $5.6 million and 281,189 shares of Calpine common stock (which were valued in the aggregate at $10.7 million at the closing of the





agreement). Additionally, the agreement provides for five equal installments of cash payments, totaling $26.7 million, beginning in January 2002, contingent upon future PSM performance. PSM specializes in the design and manufacturing of turbine hot section blades, vanes, combustors and low emissions combustion components.

*EMI Transaction*

On December 15, 2000, the Company completed the acquisition of strategic power assets from Dartmouth, Massachusetts-based Energy Management, Inc. ("EMI") for a total purchase price of $145.0 million. The purchase price included cash payments of $100.0 million and 1,102,601 shares of Calpine common stock (which were valued in the aggregate at $45.0 million at the closing of the agreement). Under the terms of the agreement, the Company acquired the remaining interest in three recently constructed combined-cycle power generating facilities located in Dighton, Massachusetts, Tiverton, Rhode Island, and Rumford, Maine, as well as Calpine-EMI Marketing LLC, a joint marketing

venture between Calpine and EMI.

*Pro Forma Effects of Acquisitions*

The table below reflects unaudited pro forma combined results of the Company, Unocal, the power plants acquired from PG&E, Sheridan, Calistoga, CCC, Vintage, KIAC, Stony Brook, Auburndale, QMCC, Agnews, Aidlin, SkyGen, TriGas, PSM, and EMI as if the acquisitions had taken place at the beginning of fiscal years 2000 and 1999 (in thousands, except per share amounts):

| | 2000 | 1999 |
|---|---|---|
| Total revenue | $2,761,867 | $1,377,554 |
| Income before extraordinary charge | $ 389,504 | $ 143,476 |
| Net income | $ 388,269 | $ 142,326 |
| Net income per basic share | $ 1.38 | $ 0.63 |
| Net income per diluted share | $ 1.24 | $ 0.60 |

In management's opinion, these unaudited pro forma amounts are not necessarily indicative of what the actual combined results of operations might have been if the acquisitions had been effective at the beginning of fiscal years 2000 and 1999. In addition, they are not intended to be a projection of future results and do not reflect all the synergies that might be achieved from combined operations.

The following merger was consummated subsequent to the year ended December 31, 2000 and was accounted for as a pooling-of-interests.

*Encal Transaction*

On April 19, 2001, the Company completed its merger with Encal, a Calgary, Alberta-based natural gas and petroleum exploration and development company. Encal shareholders received, in exchange for each share of Encal common stock, 0.1493 shares of Calpine common equivalent shares (called "exchangeable shares") of the Company's subsidiary, Calpine Canada Holdings Ltd. A total of 16,603,633 exchangeable shares were issued to Encal shareholders in exchange for all of the outstanding shares of Encal common stock. Each exchangeable share is exchangeable for one share of Calpine common stock. The aggregate value of the transaction was approximately US $1.1 billion, including the assumed indebtedness of Encal. The transaction was accounted for as a pooling-of-interests and, accordingly, all historical amounts reflected in the consolidated financial statements have been restated to reflect the transaction in accordance with Accounting Principles Board Opinion No. 16, "Business Combinations" ("APB 16"). Encal operated under the same fiscal year end as Calpine, and accordingly, Encal's balance sheets, as of December 31, 2000 and 1999, and the





statements of operations, shareholders' equity and cash flows for each of the three fiscal years in the period ended December 31, 2000 have been combined with the Company's consolidated financial statements. With the addition of Encal's assets, which currently produce approximately 230 million cubic feet of gas equivalent ("mmcfe") per day, net of royalties, Calpine's net production increased to 390 mmcfe per day in North America, enough to fuel approximately 2,300 megawatts of its power fleet.

**5. Sale and Leaseback Transactions**

On May 7, 1999, the Company entered into a sale and leaseback transaction of its 12 Sonoma County and 2 Lake County power plants, located at the Geysers, California, as well as the Sonoma power plant acquired from the Sacramento Municipal Utility District in 1998. Under the terms of the lease, the Company received $18.5 million in net proceeds and recorded a deferred gain of $15.2 million, which is being amortized as a reduction of operating lease expense over the remaining life of the lease.

On November 5, 1999, the Company entered into a sale and leaseback transaction of its Calistoga plant. Under the terms of the lease, the Company received $52.8 million in net proceeds and did not record a deferred gain or loss.

On September 1, 2000, the Company completed a leveraged lease financing transaction to provide the term financing for both Phase I and Phase II of the Pasadena, Texas Cogeneration project. Under the terms of the lease, the Company received $400.0 million in gross proceeds and recorded a deferred gain of approximately $65.0 million, which is being amortized as a reduction of operating lease expense over the remaining life of the lease.

On December 19, 2000, the Company completed leveraged lease transactions in which the Company sold the Tiverton and Rumford facilities (purchased from EMI) to a single owner lessor for $466.7 million, which then leased the facilities back to the Tiverton and Rumford subsidiaries. The Company guaranteed the obligations of the Tiverton and Rumford subsidiaries under the leases. To finance the transaction, a trust was established to issue $366.0 million of 9.0% pass through certificates due July 15, 2018, which was effected by a private placement by the trust under Rule 144A of the Securities Act of 1933. The Company recorded a deferred gain of approximately $1.7 million, which is being amortized as a reduction of operating lease expense over the remaining life of the lease. In connection with this transaction, the Company issued letters of credit. At December 31, 2000, $52.1 million in letters of credit were outstanding.

On December 22, 2000, the Company completed a leveraged lease financing transaction of its West Ford Flat and Bear Canyon projects. Under the terms of the agreement, the facilities were incorporated into the Company's Geothermal lease facility, which the Company originally entered into on May 7, 1999. The Company received $81.0 million in gross proceeds and recorded a deferred loss of approximately $8.1 million, which is being amortized as an increase of operating lease expense over the remaining life of the lease.





**6. Investments in Power Projects**

Investments, which are accounted for under the equity method, are as follows (in thousands):

| | Ownership Interest as of December 31, 2000 | December 31, 2000 | December 31, 1999 |
|---|---|---|---|
| Sumas Power Plant | (1) | $ — | $ — |
| Acadia Power Plant | 50.0% | 108,529 | — |
| Grays Ferry Power Plant | 40.0% | 30,257 | 21,875 |
| Aries Power Plant | 50.0% | 22,350 | — |
| Gordonsville Power Plant | 50.0% | 18,060 | 16,496 |
| Lockport Power Plant | 11.4% | 14,722 | 12,406 |
| Bayonne Power Plant | 7.5% | 8,385 | 8,490 |
| Tiverton Power Plant(2) | 100.0% | — | 44,853 |
| Rumford Power Plant(2) | 100.0% | — | 44,316 |
| Kennedy International Airport Power Plant(2) | 100.0% | — | 37,880 |
| Stony Brook Power Plant(2) | 100.0% | — | 21,477 |
| Auburndale Power Plant(2) | 100.0% | — | 19,565 |
| Dighton Power Plant(2) | 100.0% | — | 14,875 |
| Other | — | 3,318 | 992 |
| Total investments in power projects | | $205,621 | $243,225 |

(1) See Footnote (1) below detailing the Company's income and distributions from investments in unconsolidated power projects.

(2) The Company acquired the remaining interests in these facilities in 2000 and thereafter consolidated the operations.

The combined unaudited results of operations and financial position of the Company's equity method affiliates are summarized below (in thousands):

| | December 31, |
|---|---|

| | 2000 | 1999 | 1998 |
|---|---|---|---|
| Condensed statement of operations: | | | |
| Revenue | $ 617,914 | $ 562,401 | $ 495,123 |
| Gross profit | 217,777 | 245,314 | 214,382 |
| Income from continuing operations | 161,852 | 214,520 | 199,601 |
| Net income | 80,812 | 113,837 | 108,563 |
| Company's share of net income | 24,639 | 36,593 | 25,240 |
| Condensed balance sheet: | | | |
| Current assets | 130,316 | 167,107 | 134,794 |
| Non-current assets | 1,424,672 | 1,306,325 | 1,240,172 |
| Total assets | $1,554,988 | $1,473,432 | $1,374,966 |
| Current liabilities | 175,764 | 121,214 | 110,957 |
| Non-current liabilities | 951,013 | 1,087,329 | 994,570 |
| Total liabilities | $1,126,777 | $1,208,543 | $1,105,527 |





The following details the Company's income and distributions from investments in unconsolidated power projects (in thousands):

| | Income from Unconsolidated Investments in Power Projects | | | Distributions | | |
|---|---|---|---|---|---|---|
| | For the Years Ended December 31, | | | | | |
| | 2000 | 1999 | 1998 | 2000 | 1999 | 1998 |
| Sumas Power Plant(1) | $12,951 | $21,779 | $11,699 | $12,951 | $21,779 | $11,699 |
| Grays Ferry | 4,737 | (3) | — | 4,500 | — | — |
| Lockport Power Plant | 4,391 | 4,255 | 3,628 | 3,752 | 3,741 | 3,297 |
| Gordonsville Power Plant | 4,514 | 4,299 | 3,807 | 2,950 | 4,000 | 3,125 |
| Bayonne Power Plant | 2,196 | 3,426 | 2,446 | 2,301 | 2,808 | 2,701 |
| Stony Brook Power Plant | (994) | 857 | 252 | 1,820 | 370 | — |
| Auburndale Power Plant | 599 | (712) | (1,377) | 1,350 | 3,250 | 2,475 |
| Kennedy International Airport Power Plant | (2,769) | 1,968 | 1,159 | — | 3,350 | 4,100 |
| Other | (986) | 724 | 3,626 | 355 | 4,020 | 320 |
| Total | $24,639 | $36,593 | $25,240 | $29,979 | $43,318 | $27,717 |

(1) On December 31, 1998, the Partnership agreement governing Sumas Cogeneration Company, L.P. ("Sumas") was amended changing the distributions schedule for the Company from the previously amended agreement dated September 30, 1997. From January 1, 1998 through December, 2000, the Company recorded income equal to the amount of cash received from partnership distributions. The Company received distributions at a rate of 70% of project cashflow until December, 2000 when a cumulative 24.5% pre-tax rate of return was earned on its original investment. As a result, the Company's equity interest in the partnership has been reduced to 0.1%.

The Company provides for deferred taxes to the extent that distributions exceed earnings.

**7. Notes Payable and Borrowings Under Lines of Credit**

The components of notes payable and borrowings under lines of credit are (in thousands):

| | Borrowings Outstanding December 31, | | Letters of Credit Outstanding December 31, | |
|---|---|---|---|---|
| | 2000 | 1999 | 2000 | 1999 |
| Corporate revolving line of credit | $ 40,000 | $ — | $157,900 | $28,800 |
| Calpine Canada note payable and borrowings under line of credit | 403,705 | 208,731 | 657 | 761 |
| Calpine Natural Gas Company line of credit | — | 97,750 | — | — |
| Other | 12,449 | 38,420 | 10,810 | 10,810 |
| Total notes payable and borrowings under lines of credit | $456,154 | $344,901 | $169,367 | $40,371 |
| Less: notes payable and borrowings under lines of credit, current portion | 1,087 | 38,867 | | |
| Notes payable and borrowings under lines of credit, net of current portion | $455,067 | $306,034 | | |

In May 2000, Calpine entered into an amended and restated $400.0 million, three-year revolving line of credit with a consortium of commercial lending institutions with the Bank of Nova Scotia as agent, which





replaced an existing $100.0 million credit facility. A maximum of $200.0 million of the credit facility may be allocated to letters of credit. At December 31, 2000, the Company had $40.0 million in borrowings and $157.9 million of letters of credit outstanding under the amended and restated credit facility. At December 31, 1999, the Company had no borrowings and $28,800 in letters of credit outstanding under this credit facility. Borrowings bear variable interest and interest is paid on the last day of each interest period for such loans, at least quarterly. The credit facility specifies that the Company maintain certain covenants, with which the Company was in compliance as of December 31, 2000 and 1999. Commitment fees related to this line of credit are charged based on the unused credit. The interest rate ranged from 7.88% to 9.75% during 2000.

The Company, through its wholly owned Canadian subsidiaries, maintains a borrowing base in Canada of Cdn $304.0 million (US $202.7 million) under three facilities. At December 31, 2000, the Company had US $144.5 million outstanding under these facilities. The facilities bear interest at variable rates. The weighted average rate for each of the facilities in 2000 was 8.52%. Additionally, commitment fees of 0.25% accrue on any unused portion of these facilities. The lines of credit are secured by the Company's oil and gas reserves in Canada. As of December 31, 2000, the Company was in compliance with all covenants required under these facilities.

The Company also maintains, through its wholly owned Canadian subsidiaries, an unsecured Cdn $370.0 million (US $246.8 million) term credit facility and a Cdn $30.0 million (US $20.0 million) operating credit facility from Canadian chartered banks of which Cdn $238.7 million (US $159.2 million) and Cdn 229.2 million (US $158.7 million) was outstanding under the term credit facility at December 31, 2000 and 1999, respectively. The borrowings bear variable interest. Interest rates averaged 7.23% and 6.45% for 2000 and 1999, respectively. The term credit facility is structured as a 364-day revolving credit, extendable annually with the lenders' approval. In the event the lenders do not consent to such extension, the revolving credit will convert to a five-year non-revolving reducing facility with semi-annual principal reductions in order that the facility be repaid by the maturity date of January 30, 2006. Financial covenants require that debt not exceed the borrowing base limit of Cdn $500.0 million. As of December 31, 2000, the Company had an interest rate swap for these facilities. The swap fixes the interest rate on a notional amount of Cdn $50.0 million (US $33.3 million) at an interest rate of 6.77%. At December 31, 2000 the fair market value of this hedge was approximately US $(1,000).

In 1999, the Company, through its wholly owned subsidiary CNGC, maintained a borrowing base of $99.1 million with Bank One, Texas N.A. under two facilities. In August 2000, the Company repaid the outstanding balance of $93.3 million and terminated the agreement. As of December 31, 1999, CNGC had total borrowings of $97.8 million outstanding under this facility. The facility bore interest at variable rates. At

December 31, 1999, the interest rate was 8.6%. The lines of credit were secured by CNGC's oil and gas properties. The Company was in compliance with the financial covenants required by the facility as of December 31, 1999.

The Company, through its wholly owned Canadian subsidiaries, had two separate issues of $50.0 million unsecured notes. The first issue bears interest at 7.61% and matures on July 11, 2007. These notes are repayable in five equal annual installments of $10.0 million beginning July 11, 2003, with interest payable semi-annually in arrears until maturity. The second issue bears interest at 8.06% with a 10 year term maturing December 21, 2010. These 8.06% notes are repayable in five equal, annual installments of $10.0 million beginning December 21, 2006 with interest payable quarterly in arrears until maturity.

Additionally, in connection with repayment of outstanding borrowings in August 2000, the termination of certain credit agreements and the related write-off of unamortized deferred financing costs, the Company recorded an extraordinary loss of $1.2 million after taxes.





**8. Project Financing and Interest Rate Swap Agreements**

The components of project financing as of December 31, 2000 and 1999 are (in thousands):

| | Interest Rate(1) | | | Outstanding at December 31, | | Letters of Credit Outstanding(3) |
|---|---|---|---|---|---|---|
| **Projects** | **2000** | **1999** | **Final Maturity** | **2000** | **1999** | **2000** |
| Calpine Construction Finance Company(2) | 8.39% | — | 2004 | $ 701,644 | $ — | $ — |
| Auburndale Power Plant | 7.51% | — | 2012 | 121,464 | — | — |
| Newark & Parlin Power Plants | 7.68% | 6.51% | 2011 | 116,715 | 125,318 | — |
| Broad River Energy Center | 8.02% | — | 2007 | 115,880 | — | 34,831 |
| Pine Bluff Energy Center | 8.22% | — | 2018 | 113,197 | — | 21,333 |
| Hog Bayou Energy Center | 8.24% | — | 2002 | 107,974 | — | 29,003 |
| RockGen Energy Center | 7.97% | — | 2007 | 89,840 | — | 16,095 |
| Morris Power Plant | 7.39% | 7.50% | 2004 | 85,600 | 85,622 | — |
| DePere Energy Center | 7.68% | — | 2017 | 47,243 | — | 4,444 |
| Dighton Power Plant | 7.79% | — | 2019 | 32,798 | — | — |
| Pasadena Power Plant | — | 5.58% | 2005 | — | 154,800 | — |
| Total | | | | 1,532,355 | 365,740 | $105,706 |
| Less: current portion | | | | 58,486 | 8,603 | |
| Long-term project financing | | | | $1,473,869 | $357,137 | |

(1) Weighted average rate before giving effect to amortization of financing cost or interest rate swaps. The fair value of each of the project financings approximates the carrying value.

(2) Represents rate at December 31, 2000.

(3) No letters of credit associated with project financings in 1999.

*Calpine Construction Finance Company Debt*

In November 1999, the Company entered into a credit agreement for $1.0 billion through its wholly owned subsidiary Calpine Construction Finance Company L.P. with a consortium of banks with the lead arranger being The Bank of Nova Scotia and the lead arranger syndication

agent being Credit Suisse First Boston. The non-recourse credit facility is utilized to finance the construction of the Company's diversified portfolio of gas-fired power plants currently under development. The Company currently intends to refinance this construction facility in the long-term capital markets prior to its four-year maturity. As of December 31, 2000, the Company had $544.8 million in borrowings outstanding under the facility. Borrowings under this facility bear variable interest. The credit facility specifies that the Company maintain certain covenants, with which the Company was in compliance as of December 31, 2000. The interest rate at December 31, 2000 was 8.44%. The interest rate ranged from 7.38% to 9.50% during 2000.

In October 2000, the Company entered into a credit agreement for $2.5 billion through its wholly owned subsidiary Calpine Construction Finance Company II, LLC with a consortium of banks with the lead arrangers being The Bank of Nova Scotia and Credit Suisse First Boston. The non-recourse credit facility is utilized to finance the construction of the Company's diversified portfolio of gas-fired power plants currently under development. The Company currently intends to refinance this construction facility in the long-term capital markets prior to its four-year maturity. As of December 31, 2000, the Company had $156.8 million in borrowings outstanding under the facility. Borrowings under this facility bear variable interest. The credit





facility specifies that the Company maintain certain covenants, with which the Company was in compliance as of December 31, 2000. The interest rate at December 31, 2000 was 8.20%. The interest rate ranged from 8.20% to 10.25% during 2000.

*Auburndale Power Plant Debt*

As part of the Company's acquisition of the Auburndale Power Plant, the Company assumed a project loan. This facility provides for project financing loans aggregating $126.0 million. Amounts outstanding under the facility bear interest at variable rates. The weighted average interest rate for 2000 was 7.51%. The effective interest rate for 2000, after giving effect to an interest rate swap, was 7.82%.

*Newark & Parlin Power Plant Debt*

On December 17, 1999, the Company acquired 80% of the common stock of CCC which owns 100% of the Newark and Parlin Power Plants ("Newark & Parlin"). At December 31, 2000 there was $116.7 million outstanding on a fifteen year non-recourse term loan which is a joint and severable liability of Newark & Parlin. The term loan is secured by all Newark & Parlin assets and a pledge of their capital stock. CCC has guaranteed repayment of up to $25.0 million of the term loan based on the principal balance of the loan, and also guaranteed payment by Newark & Parlin of all income and franchise taxes when due. CCC's guarantee is reduced proportionately to the outstanding principal as payments are made on the debt. The balance of the guarantee was $18.8 million as of December 31, 2000. The interest rate on the outstanding principal is variable and averaged 7.68% in 2000. The effective interest rate for 2000, after giving effect to the interest rate swap, was 8.07%. Interest on the loan is payable at least quarterly.

*Broad River Energy Center Debt*

As part of the Company's acquisition of SkyGen, the Company assumed a term loan and a steam injection addition loan for the Broad River Energy Center. The steam injection loan is expected to be converted to a term loan in 2001. The construction loans require only interest payments through the conversion date, and blended payments of principal and interest following conversion to a term loan. Interest on the construction loan is variable and averaged 8.02% for 2000. The effective interest rate for 2000, after giving effect to interest rate swaps, was 7.34%.

*Pine Bluff Energy Center Debt*

As part of the Company's acquisition of SkyGen, the Company assumed construction financing for the Pine Bluff Energy Center, a limited liability corporation (LLC). Under the terms of the credit facility, the Company can borrow up to $142.0 million to fund construction. Of this amount, $32.0 million is secured by guarantees or letters of credit from the members of the LLC or their affiliates. Upon completion of construction, equity contributions of $32.0 million will be made to repay a portion of the construction loan and the balance of the construction loan will be converted to a term loan. The term loan will consist of three tranches: Tranche A in the amount of $30.0 million with a maturity date of 8 1/2 years from the conversion date, Tranche B in the amount of $45.0 million with a maturity date of 13 1/2 years from the conversion date, and Tranche C in the amount of $35.0 million with a maturity date of 17 1/2 years from the conversion date. The construction loan requires only interest payments through the conversion date, and blended payments of principal and interest following conversion to a term loan. Interest on the construction loan is variable and averaged 8.22% during 2000. The effective interest rate for 2000, after giving effect to interest rate swaps, was 7.34%.

*Hog Bayou Energy Center Debt*

As part of the Company's acquisition of SkyGen, the Company entered into an arrangement with a syndicate of commercial banks to obtain financing to construct the Hog Bayou Energy Center. As part of the related credit agreement, the lenders will provide a facility to fund construction whereby the Company can borrow up to $38.0 million under an equity bridge loan and $104.6 million under a construction loan. The equity bridge loan matures on December 31, 2001 and the construction loan matures on December 31, 2002. As of December 31, 2000, the Company has borrowed $38.0 million under the equity bridge loan and $70.0 million under the construction loan. The weighted average interest rate for the facilities was 8.24% in 2000.

*RockGen Energy Center Debt*

As part of the Company's acquisition of SkyGen, the Company entered into financing for the RockGen Energy Center. As part of the related credit agreement, the lender provided a facility whereby the Company can borrow up to $152.6 million in construction loans. Upon completion of construction, the balance of the construction loans will be converted to a term loan which matures on March 1, 2007. The construction loans require only interest payments through the conversion date, and blended payments of principal and interest following the conversion date. The weighted average interest rate during 2000 was 7.97%.

*Morris Power Plant Debt*

On December 17, 1999, the Company acquired 80% of the common stock of CCC which owns 100% of Morris LLC ("Morris"). In 1997, Morris entered into a construction and term loan agreement to provide non-recourse project financing for a major portion of the Morris Project. The agreement provides $85.6 million of 5-year term loan commitments and $5.4 million in letter of credit commitments. As of December 31, 2000, $85.6 million was outstanding as a term loan under the agreement and no amounts were pledged under the letter of credit. Interest on the term loan is variable and averaged 7.39% in 2000. Borrowings are secured by CCC's ownership interest in Morris, its cash flows, dividends and any other property of Morris.

*DePere Energy Center Debt*

As part of the Company's acquisition of SkyGen, the Company assumed a term loan. Interest is payable based on the rate of the interest rate swap plus an applicable margin. The weighted average interest rate, before and after swap effects, was 7.68% and 6.43%, respectively.

*Dighton Power Plant Debt*

In December 2000, the Company acquired the remaining interest in the Dighton Power Plant. The Company assumed project financing for the plant. The weighted average interest rate as of December 31, 2000 was 7.79%.

*Pasadena Power Plant Debt*

On January 4, 1999, the Company entered into a credit agreement with ING (U.S.) Capital LLC ("ING") to provide up to $265.0 million of non-recourse project financing for the construction of the Pasadena facility expansion. On August 31, 2000, the Company repaid the outstanding balance of $224.2 million under the credit agreement.

*Additional Interest Rate Swap Agreements*

The Company acquired an interest rate swap agreement with the purchase of the Auburndale Power Plant on June 30, 2000. The agreement was entered into to fix the project's floating rate debt. The swap fixes

the interest rate on a notional amount of $121.5 million at a weighted average rate of 6.5%. At December 31, 2000, the fair market value of this hedge was approximately $(3.7) million.

The Company acquired ten interest rate swap agreements with the purchase of SkyGen on October 12, 2000. The agreements were entered into by SkyGen to fix the floating rate debt for its RockGen, Broad River, DePere, and Pine Bluff projects. The swaps fix the interest rates on an aggregate notional amount of $303.1 million at a weighted average rate of 7.3%. At December 31, 2000, the fair market value of these hedges was approximately $(16.4) million.

Upon adoption of SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities," the hedges will be accounted for using the methodology described in Note 2.

**9. Senior Notes**

Senior Notes payable consist of the following as of December 31, 2000 and 1999 (in thousands):

| | Interest Rates | First Call Date | December 31, 2000 | December 31, 1999 | Fair Value as of 2000 | Fair Value as of 1999 |
|---|---|---|---|---|---|---|
| Senior Notes due 2004 | 9 1/4% | 1999 | $ 105,000 | $ 105,000 | $ 105,000 | $ 106,050 |
| Senior Notes due 2005 | 8 1/4% | (2) | 250,000 | — | 246,700 | — |
| Senior Notes due 2006 | 10 1/2% | 2001 | 171,750 | 171,750 | 178,620 | 180,939 |
| Senior Notes due 2006 | 7 5/8% | (1) | 250,000 | 250,000 | 239,700 | 238,050 |
| Senior Notes due 2007 | 8 3/4% | 2002 | 275,000 | 275,000 | 266,750 | 275,963 |
| Senior Notes due 2008 | 7 7/8% | (1) | 400,000 | 400,000 | 380,320 | 384,600 |
| Senior Notes due 2009 | 7 3/4% | (1) | 350,000 | 350,000 | 332,535 | 320,950 |
| Senior Notes due 2010 | 8 5/8% | (2) | 750,000 | — | 726,600 | — |
| Total | | | $2,551,750 | $1,551,750 | $2,476,225 | $1,506,552 |

(1) Not redeemable prior to maturity.

(2) Redeemable at any time prior to maturity.

The Company has completed a series of public debt offerings since 1994. Interest is payable semiannually at specified rates. There are no sinking fund or mandatory redemptions of principal before the maturity dates of each offering. Certain of the Senior Note indentures limit the Company's ability to incur additional debt, pay dividends, sell assets and enter into certain transactions. As of December 31, 2000 the Company is in compliance with all debt covenants relating to the Senior Notes.

*Senior Notes Due 2004*

The Senior Notes due 2004 bear interest at 9 1/4% per year, payable semi-annually on February 1 and August 1 each year and mature on February 1, 2004. The Senior Notes due 2004 are redeemable, at the option of the Company, at any time on or after February 1, 1999 at various redemption prices. In addition, the Company may redeem up to $36.8 million of the Senior Notes due 2004 from the proceeds of any public equity offering. The effective interest rate on the $105.0 million, after amortization of deferred financing costs, was 9.6%.

*Senior Notes Due 2005*

On August 10, 2000, the Company completed a public offering of $250.0 million of its 8 1/4% Senior Notes due 2005 ("Senior Notes due 2005"). The Senior Notes due 2005 bear interest at 8 1/4% per year, payable semi-annually on August 15 and February 15 and mature on August 15, 2005. The Senior Notes due 2005

may be redeemed at any time prior to maturity at a redemption price equal to 100% of their principal amount plus accrued and unpaid interest plus a make-whole premium. The effective interest rate on the $250.0 million, after amortization of deferred financing costs, was 8.6%.

*Senior Notes Due 2006*

The Senior Notes due 2006 bear interest at 10 1/2% per year, payable semi-annually on May 15 and November 15 each year and mature on May 15, 2006. The Senior Notes due 2006 are redeemable, at the option of the Company, at any time on or after May 15, 2001 at various redemption prices. In addition, the Company may redeem up to $63.0 million of the Senior Notes due 2006 from the proceeds of any public equity offering. The effective interest rate on the $171.8 million, after amortization of deferred financing costs, was 10.8%.

Additionally, during 1999 the Company completed a public offering of $250.0 million of its 7 5/8% Senior Notes due 2006 ("1999 Senior Notes due 2006"). The 1999 Senior Notes due 2006 bear interest at 7 5/8% per year, payable semi-annually on April 15 and October 15 and mature on April 15, 2006. The 1999 Senior Notes due 2006 are not redeemable prior to maturity. The effective interest rate on the $250.0 million, after amortization of deferred financing costs, was 7.9%.

*Senior Notes Due 2007*

The Senior Notes due 2007 bear interest at 8 3/4% per year, payable semi-annually on January 15 and July 15 each year and mature on July 15, 2007. The Senior Notes due 2007 are redeemable, at the option of the Company, at any time on or after July 15, 2002 at various redemption prices. In addition, the Company may redeem up to $96.3 million of the Senior Notes due 2007 from the proceeds of any public equity offering. The effective interest rate on the $275.0 million, after amortization of deferred financing costs, was 9.1%.

*Senior Notes Due 2008*

The Senior Notes due 2008 bear interest at 7 7/8% per year, payable semi-annually on April 1 and October 1 each year and mature on April 1, 2008. The Senior Notes due 2008 are not redeemable prior to maturity. The effective interest rate on the $400.0 million, after amortization of deferred financing costs, was 8.0%.

*Senior Notes Due 2009*

The Senior Notes due 2009 bear interest at 7 3/4% per year, payable semi-annually on April 15 and October 15 and mature on April 15, 2009. The Senior Notes due 2009 are not redeemable prior to maturity. The effective interest rate on the $350.0 million, after amortization of deferred financing costs, was 7.9%.

*Senior Notes Due 2010*

On August 10, 2000, the Company completed a public offering of $750.0 million of its 8 5/8% Senior Notes due 2010 ("Senior Notes due 2010"). The Senior Notes due 2010 bear interest at 8 5/8% per year, payable semi-annually on August 15 and February 15 and mature on August 15, 2010. The Senior Notes due 2010 may be redeemed at any time prior to maturity at a redemption price equal to 100% of their principal amount plus accrued and unpaid interest plus a make-whole premium. The effective interest rate on the $750.0 million, after amortization of deferred financing costs, was 8.7%.





*Annual Debt Maturities*

The annual principal maturities of the borrowings under lines of credit, project financings, notes payable and senior notes as of December 31, 2000 are as follows (in thousands):

| | |
|---|---|
| 2001 | $ 59,573 |
| 2002 | 96,033 |

| | |
|---|---|
| 2003 | 622,552 |
| 2004 | 377,554 |
| 2005 | 289,964 |
| Thereafter | 3,094,583 |
| Total | $4,540,259 |

**10. Capital Lease Obligations**

During 2000, the Company assumed and began to consolidate capital leases in conjunction with the acquisitions of the Hidalgo Energy Center, the Stony Brook Power Plant and the Agnews Power Plant. The asset balances for the leased assets totaled $181.7 million at December 31, 2000, with accumulated amortization of $3.4 million.

The following is a schedule by years of future minimum lease payments under capital leases together with the present value of the net minimum lease payments as of December 31, 2000 (in thousands):

| | |
|---|---|
| Year Ending December 31: | |
| 2001 | $ 17,215 |
| 2002 | 17,174 |
| 2003 | 17,956 |
| 2004 | 18,223 |
| 2005 | 18,369 |
| Thereafter | 349,562 |
| Total minimum lease payments | 438,499 |
| Less: Amount representing interest(1) | (227,638) |
| Present value of net minimum lease payments | $ 210,861 |
| Less: Capital lease obligation, current portion | (1,985) |
| Capital lease obligation, net of current portion | $ 208,876 |

(1) Amount necessary to reduce net minimum lease payments to present value calculated at the implicit interest rates of the leases at their inception.

**11. Trust Preferred Securities**

In 1999 and 2000, the Company, through its wholly-owned subsidiaries, Calpine Capital Trust, Calpine Capital Trust II and Calpine Capital Trust III, statutory business trusts created under Delaware law, (collectively, “the Trusts”) completed offerings of Remarketable Term Income Deferrable Equity Securities (“trust preferred securities” or “HIGH TIDES”) at a value of $50.00 per share. In 1999, the Company and Calpine Capital Trust had a private placement of 5,520,000 shares, including the purchasers’ option. In January and February of 2000 the Company and Calpine Capital Trust II privately placed 7,200,000 shares, including the purchasers’ option. In August 2000, the Company and Calpine Capital Trust III privately placed





10,350,000 shares, including the underwriters’ over-allotment option. At December 31, 2000, the balance for each of these issuances was $268.2, $350.9 and $503.4, respectively.

The net proceeds from each of the offerings were used by the Trusts to invest in convertible subordinated debentures of the Company,

which represent substantially all of the respective trusts' assets. The Company has effectively guaranteed all of the respective trusts' obligations under the trust preferred securities. The trust preferred securities accrue distributions at rates of 5 3/4%, 5 1/2% and 5% per annum, respectively, and have liquidation values of $50.00 per share. The Company has the right to defer the interest payments on the debentures for up to twenty consecutive quarters, which would also cause a deferral of distributions on the trust preferred securities. Currently, the Company has no intention of deferring interest payments on the debentures. The trust preferred securities are convertible into shares of the Company's common stock at the holder's option on or prior to the tender notification date, at rates of 3.4260, 1.9524 and 1.1510 shares, respectively, of common stock for each trust preferred security.

The 1999 issuance may be redeemed at any time on or after November 5, 2002 at a redemption price equal to 101.44% of the principal amount plus any accrued and unpaid interest declining to 100% of the principal amount on or after November 5, 2003. The second issuance of HIGH TIDES may be redeemed at any time on or after February 5, 2003 at a redemption price equal to 101.375% of the principal amount plus any accrued and unpaid distributions declining to 100% of the principal amount on or after February 5, 2004. The August 2000 issuance may be redeemed at any time on or after August 5, 2003 at a redemption price equal to 101.25% of the principal amount plus any accrued and unpaid distributions declining to 100% of the principal amount on or after August 5, 2004.

**12. Provision for Income Taxes**

The components of the deferred income taxes, net as of December 31, 2000 and 1999 are as follows (in thousands):

| | 2000 | 1999 |
|---|---|---|
| Expenses deductible in a future period | $ 32,293 | $ 11,666 |
| Net operating loss and credit carryforwards | 41,472 | 50,358 |
| Other differences | 2,339 | 1,545 |
| Deferred tax assets | 76,104 | 63,569 |
| Property differences | (681,043) | (349,936) |
| Difference in taxable income and income from investments recorded on the equity method | — | (2,305) |
| Other differences | (15,868) | (11,160) |
| Deferred tax liabilities | (696,911) | (363,401) |
| Net deferred income taxes | $(620,807) | $(299,832) |

The net operating loss and credit carryforwards consist of federal and state net operating loss carryforwards which expire 2005 through 2014 and federal depletion deduction carryforwards which can be carried forward indefinitely. The federal and state net operating loss carryforwards available are subject to limitations on annual usage. It is expected that they will be fully utilized before expiring. At December 31, 2000, federal and state alternative minimum tax credit carryforwards were fully utilized. Realization of the deferred tax assets and federal net operating loss carryforwards is dependent, in part, on generating sufficient taxable income prior to expiration of the loss carryforwards. The amount of the deferred tax asset considered realizable, however, could be reduced in the near term if estimates of future taxable income during the carryforward period are reduced.





The provision for income taxes for the years ended December 31, 2000, 1999 and 1998 consists of the following (in thousands):

| | 2000 | 1999 | 1998 |
|---|---|---|---|
| Current: | | | |
| Federal | $214,169 | $26,564 | $ 1,582 |
| State | 40,596 | 6,728 | 277 |
| Foreign | — | — | — |
| Deferred: | | | |

| | | | |
|---|---|---|---|
| Federal | (30,573) | 23,142 | 26,830 |
| State | (7,852) | 4,305 | 1,772 |
| Adjustment in state tax rate (net of federal benefit) | — | — | (4,826) |
| Revision in prior years' tax estimates | — | 1,234 | 1,419 |
| Foreign | 48,469 | 6,085 | (5,871) |
| Total provision | $264,809 | $68,058 | $21,183 |

The Company's effective rate for income taxes for the years ended December 31, 2000, 1999 and 1998 differs from the United States statutory rate, as reflected in the following reconciliation:

| | 2000 | 1999 | 1998 |
|---|---|---|---|
| United States statutory tax rate | 35.0% | 35.0% | 35.0% |
| State income tax, net of federal benefit | 3.9 | 3.6 | 3.8 |
| Depletion allowance | — | — | (1.5) |
| Foreign tax at rates other than U.S. statutory | 1.7 | (0.5) | (1.8) |
| Other, net | 0.9 | 0.6 | (0.4) |
| Effective income tax rate | 41.5% | 38.7% | 35.1% |

**13. Employee Benefit Plans**

*Retirement Savings Plan*

The Company has a defined contribution savings plan under Section 401(a) and 501(a) of the Internal Revenue Code. The plan provides for tax deferred salary deductions and after-tax employee contributions. Employees are immediately eligible upon hire. Contributions include employee salary deferral contributions and a 3% employer profit-sharing contribution. Employer profit-sharing contributions in 2000, 1999 and 1998 totaled $3.1 million, $1.3 million and $0.8 million, respectively.

*1996 Employee Stock Purchase Plan*

The Company adopted the 1996 Employee Stock Purchase Plan in July 1996. Eligible employees could purchase up to 2,200,000 shares of common stock at semi-annual intervals through periodic payroll deductions. Purchases were limited to 15 percent of an employee's eligible compensation, and to a maximum value of $25,000 per calendar year based on the IRS code Section 423 limitation. Shares were purchased on January 31, and the plan terminated on February 1, 2000. Under the 1996 plan, 408,300 shares were issued at a weighted average fair value of $2.67 per share in 2000. The purchase price is 85% of the lower of (i) the fair market value of the common stock on the participant's entry date into the offering period, or (ii) the fair market value on the semi-annual purchase date.





*2000 Employee Stock Purchase Plan*

The Company adopted the 2000 Employee Stock Purchase Plan ("ESPP") in May 2000. Eligible employees may purchase up to 4,000,000 shares of common stock at semi-annual intervals through periodic payroll deductions. Purchases are limited to a maximum value of $25,000 per calendar year based on the IRS code Section 423 limitation. Shares are purchased on May 31 and November 30 of each year until termination of the plan on May 30, 2002. Under the ESPP, 221,853 shares were issued at a weighted average fair value of $23.18 per share in 2000. The purchase price is 85% of the lower of (i) the fair market value of the common stock on the participant's entry date into the offering period, or (ii) the fair market value on the semi-annual purchase date.

*1996 Stock Incentive Plan*

The Company adopted the 1996 Stock Incentive Plan ("SIP") in September 1996. The SIP succeeded the Company's previously adopted stock option program. The Company accounts for the SIP under Accounting Principles Board Opinion No. 25, "Accounting for Stock Issued to Employees" under which no compensation cost has been recognized. Had compensation cost for the SIP been determined consistent with the methodology of SFAS No. 123, "Accounting for Stock-Based Compensation", the Company's net income and earnings per share would have been reduced to the following pro forma amounts (in thousands, except per share amounts):

| | | 2000 | 1999 | 1998 |
|---|---|---|---|---|
| Net income | As reported | $372,602 | $106,650 | $38,517 |
| | Pro Forma | 351,219 | 94,313 | 34,335 |
| Earnings per share data: | | | | |
| Basic earnings per share | As reported | $ 1.33 | $ 0.47 | $ 0.22 |
| | Pro Forma | 1.25 | 0.42 | 0.19 |
| Diluted earnings per share | As reported | $ 1.19 | $ 0.45 | $ 0.21 |
| | Pro Forma | 1.13 | 0.39 | 0.19 |

The fair value of options granted in 2000, 1999 and 1998 was $16.09, $6.42 and $3.68 on the date of grant using the Black-Scholes option pricing model with the following weighted-average assumptions: expected dividend yields of 0%, expected volatility of 67% for 2000, 69% for 1999 and 35% for 1998, risk-free interest rates of 6.69% for 2000, 5.74% for 1999, 5.25% for 1998, respectively, and expected lives of 7 years for 2000, 1999 and 1998.

As of December 31, 2000, the Company had granted options to purchase 36,849,010 shares of common stock, net of cancellations. Over the life of the SIP, options exercised have equaled 7,337,624, leaving 29,511,386 granted and not yet exercised. Under the SIP, the option exercise price generally equals the stock's fair market value on date of grant. The SIP options generally vest ratably over four years and expire after 10 years.

*Encal Stock Option Plan*

In connection with the merger with Encal, the Company adopted Encal's existing stock option plan. All outstanding options under the Encal stock option plan were converted at the time of the merger into options to purchase Calpine stock. No new options may be granted under the Encal stock option plan. At December 31, 2000, the Encal stock option plan consists of outstanding options to purchase 1,116,644 Calpine common shares at prices ranging from US $16.30 to US $41.08 per share and expiring from 2001 to 2005.





Changes in options outstanding, granted, exercisable and cancelled during the years 2000, 1999 and 1998, under the option plans of Calpine and Encal were as follows:

| | Available for Option or Award | Number of Shares | Weighted Average Exercise Price |
|---|---|---|---|
| Outstanding January 1, 1998 | 12,961,819 | 21,023,260 | $ 1.36 |
| Additional shares reserved | 1,604,856 | — | — |
| Granted | (3,773,912) | 3,773,912 | 4.43 |
| Exercised | — | (486,946) | 6.78 |
| Cancelled | 200,718 | (200,718) | 3.52 |
| Outstanding December 31, 1998 | 10,993,481 | 24,109,508 | 1.72 |
| Additional shares reserved | 1,911,527 | — | — |
| Granted | (8,604,108) | 8,604,108 | 7.32 |
| Exercised | — | (1,686,228) | 3.54 |
| Cancelled | 61,799 | (61,799) | 15.20 |
| Outstanding December 31, 1999 | 4,362,699 | 30,965,589 | 3.18 |

| | | | |
|---|---|---|---|
| Additional shares reserved | 2,820,757 | — | |
| Granted | (4,379,129) | 4,379,129 | 23.21 |
| Exercised | — | (4,533,946) | 1.89 |
| Cancelled | 182,742 | (182,742) | 17.68 |
| Outstanding December 31, 2000 | 2,987,069 | 30,628,030 | $ 6.11 |
| Options exercisable: | | | |
| December 31, 1998 | | 15,812,494 | $ 0.93 |
| December 31, 1999 | | 17,829,699 | 1.19 |
| December 31, 2000 | | 18,980,332 | 2.68 |

The following tables summarizes information concerning outstanding and exercisable options at December 31, 2000:

| | Outstanding Options | | | Options Exercisable | |
|---|---|---|---|---|---|
| Range of Exercise Prices | Number of Shares | Weighted Average Remaining Contractual Life in Years | Weighted Average Exercise Price | Number of Shares | Weighted Average Exercise Price |
| $ 0.065 – $ 0.065 | 5,156,560 | 2.00 | $ 0.065 | 5,156,560 | $ 0.065 |
| $ 0.570 – $ 0.615 | 3,976,896 | 4.09 | 0.597 | 3,976,896 | 0.597 |
| $ 0.645 – $ 1.070 | 2,999,856 | 5.30 | 1.060 | 2,999,856 | 1.060 |
| $ 1.105 – $ 2.250 | 5,305,492 | 6.79 | 2.173 | 3,148,092 | 2.167 |
| $ 2.345 – $ 3.320 | 645,950 | 7.07 | 2.856 | 587,950 | 2.895 |
| $ 3.750 – $ 3.860 | 4,032,250 | 8.12 | 3.859 | 896,650 | 3.859 |
| $ 4.240 – $ 9.955 | 3,398,266 | 8.57 | 9.136 | 933,354 | 8.935 |
| $ 10.000 – $ 23.190 | 3,858,030 | 6.26 | 19.959 | 1,063,477 | 17.799 |
| $ 23.205 – $ 51.282 | 1,223,730 | 5.17 | 33.682 | 217,497 | 26.369 |
| $100.000 – $100.000 | 31,000 | 9.70 | 100.000 | — | — |
| Total | 30,628,030 | 5.74 | $ 6.112 | 18,980,332 | $ 2.681 |





**14. Stockholders' Equity**

*Common Stock*

Stock Splits — On September 20, 1999, the Board of Directors authorized a two-for-one stock split of the Company's common stock, in the form of a stock dividend, effective October 7, 1999, payable to stockholders of record as of September 28, 1999. The Company transferred $27,000 to common stock from additional paid-in capital, representing the aggregate par value of the shares issued under the stock split.

On May 18, 2000, the Board of Directors authorized a two-for-one stock split of the Company's common stock, in the form of a stock dividend, effective June 8, 2000, payable to stockholders of record as of May 29, 2000. The Company transferred $64,000 to common stock from additional paid-in capital, representing the aggregate par value of the shares issued under the stock split.

On October 23, 2000, the Board of Directors authorized a two-for-one stock split of the Company's common stock, in the form of a stock dividend, effective November 14, 2000, payable to stockholders of record as of November 6, 2000. The Company transferred $140,000 to common stock from additional paid-in capital, representing the aggregate par value of the shares issued under the stock split.

All references to the number of common shares and the per common share amounts have been restated to give retroactive effect to the above stock splits for all periods presented.

*Equity Offering* — On August 9, 2000, Calpine completed a public offering of 23,000,000 shares of common stock at $34.75 per share. The gross proceeds from the offering were $799.3 million.

*Preferred Stock and Preferred Share Purchase Rights*

On June 5, 1997, the Board of Directors adopted a Stockholders Rights Plan ("Rights Plan") to strengthen the Board of Directors ability to protect the Company's stockholders. The Rights Plan is designed to protect against abusive or coercive takeover tactics that are not in the best interests of the Company and its stockholders. To implement the Rights Plan, the Board of Directors declared a dividend of one preferred share purchase right (a "Right") for each outstanding share of common stock, par value $0.001 per share, held on record as of June 18, 1997, and directed the issuance of one Right with respect to each share of Common Stock that shall become outstanding between the Record Date and the Distribution Date. On December 31, 2000, there were 283,715,058 Rights outstanding. Each Right initially represents a contingent right to purchase, under certain circumstances, one one-thousandth of a share (a "Unit") of Series A Junior Participating Preferred Stock, par value $0.001 per share (the "Preferred Stock"), of the Company at a price of $80.00 per Unit, subject to adjustment. The Rights become exercisable and trade independently from the Company's common stock upon the public announcement of the acquisition by a person or group of 15% or more of the Company's common stock, or ten days after commencement of a tender or exchange offer that would result in the acquisition of 15% or more of the Company's common stock. Each Unit of Preferred Stock purchased upon exercise of the Rights will be entitled to a dividend equal to any dividend declared per share of common stock and will have one vote, voting together with the common stock. In the event of liquidation, each share of Preferred Stock will be entitled to any payment made per share of common stock.

If the Company is acquired in a merger or other business combination transaction after a person or group has acquired 15% or more of the Company's common stock, each Right will entitle its holder to purchase at the Right's exercise price a number of the acquiring company's common shares having a market value of twice such exercise price. In addition, if a person or group acquires 15% or more of the Company's common stock, each Right will entitle its holder (other than the acquiring person or group) to purchase, at the Right's exercise price, a number of fractional shares of the Company's Preferred Stock or shares of common stock having a market value of twice such exercise price.





The Rights expire June 18, 2007, unless redeemed earlier by the Company's Board of Directors. The Board of Directors can redeem the Rights at a price of $0.01 per Right at any time before the Rights become exercisable, and thereafter only in limited circumstances.

**15. Significant Customers**

The Company has two significant customers, Pacific Gas & Electric Company ("PG&E") and Texas Utilities Electric Company ("TUEC"), each of which has accounted for 10% or more of the Company's annual consolidated revenues for certain years between 1998 and 2000.

The Company's northern California Qualifying Facility ("QF") subsidiaries sell power to PG&E under the terms of long-term contracts at eleven facilities. On April 6, 2001, PG&E filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code. PG&E is the regulated subsidiary of PG&E Corporation, and the information on PG&E disclosed below excludes PG&E Corporation's non-regulated subsidiary activity. The Company has transactions with certain of the non-regulated subsidiaries, which have not been affected by PG&E's bankruptcy.

The Company's QF contracts with PG&E provide that the California Public Utilities Commission ("CPUC") has the authority to determine the appropriate utility "avoided cost" to be used to set energy payments for certain QF contracts, including those for all of the Company's QF plants in California which sell power to PG&E. Section 390 of the California Public Utility Code provides QFs the option to elect to receive energy payments based on the California Power Exchange Corporation ("PX") market clearing price. In mid 2000, the Company's QF facilities elected this option and were paid based upon the PX zonal day-ahead clearing price ("PX Price") from summer 2000 until January 19, 2001, when the PX ceased operating a day-ahead market. Since that time, the CPUC has ordered that the price to be paid for energy deliveries by QFs electing the PX Price shall be based on a natural gas cost-based "transition formula." The CPUC has conducted proceedings (R.99-11-022) to determine whether the PX Price was the appropriate price for the energy component upon which to base payments to QFs which had elected the PX-based pricing option. The CPUC has issued a proposed decision to the effect that the PX Price was the appropriate price for energy payments under the California Public Utility Code. However, a final decision has not been issued to date. Therefore, it is possible that the CPUC could order a payment adjustment based on a different energy price determination. The Company believes that the PX Price was the appropriate price for energy payments but there can be no assurance that this will be the outcome of the CPUC proceedings.

On March 28, 2001, the CPUC issued an order (Decision 01-03-067) (the "March 2001 Decision") proposing to change, on a prospective basis, the composition of the short run avoided cost ("SRAC") energy price formula, which is reset monthly, used by the California utilities in QF contracts. Prior to the March 2001 Decision, CPUC regulations calculated SRAC based on 50% Topock and 50% Malin border gas indices. In the March 2001 Decision, the CPUC changed this formulation to eliminate the prices at Topock from the SRAC formula. The March 2001 Decision is subject to challenges at the CPUC and the Federal Energy Regulatory Commission.

Revenues earned from PG&E and TUEC for the years ended December 31, 2000, 1999 and 1998 were as follows (in thousands):

| | 2000 | 1999 | 1998 |
|---|---|---|---|
| **Revenues:** | | | |
| PG&E (1) | $624,458 | $215,264 | $222,593 |
| TUEC | 184,017 | 144,016 | 128,724 |





Receivables due from PG&E and TUEC at December 31, 2000 and 1999 were as follows (in thousands):

| | 2000 | 1999 |
|---|---|---|
| **Receivables:** | | |
| PG&E Accounts Receivable | $204,448 | $33,251 |
| PG&E Notes Receivable (2) | 62,336 | 13,919 |
| PG&E Total | $266,784 | $47,170 |
| TUEC Accounts Receivable | $ 25,397 | $ 9,918 |

(1) See Note 19 for further discussion of the California energy situation.

(2) Payments of the notes receivable are scheduled from February 2003 until September 2014 (See Note 2 for further discussion).

As of April 6, 2001, the Company had recorded approximately $266 million (unaudited estimate) in accounts receivable with PG&E under the QF contracts, plus $69 million (unaudited estimate) in notes receivable not yet due and payable. PG&E has paid currently for power delivered after April 6, 2001, the date of PG&E's bankruptcy filing.

As of April 19, 2001, the Company had received from PG&E subsequent accounts receivable collections of $94.1 million relating to the balances outstanding at December 31, 2000. These collections represent 100% of November 2000 billings and approximately 15% of December billings. Additionally, the Company collected approximately 15% of amounts billed to PG&E in January 2001. The Company continues to sell power to PG&E pursuant to its long-term contracts and believes that the accounts receivable will ultimately be collected. However, the situation in California is highly uncertain and the Company cannot predict the outcome or the timing of payments from PG&E for past due amounts.

The Company also had combined accounts receivable balances of $45.2 million as of December 31, 2000 due from the California Independent System Operator Corporation ("CAISO") and Automated Power Exchange, Inc. ("APX"). As of April 19, 2001, subsequent collections and 2001 activity resulted in an estimated receivable balance of approximately $13.7 million (unaudited estimate) due from these two entities. CAISO's ability to pay the Company is directly impacted by PG&E's ability to pay CAISO. APX's ability to pay the Company is impacted by PG&E's ability to pay the California Power Exchange ("PX"), which in turn pays APX for energy deliveries by the Company through APX. The Company has provided for a reserve against collection uncertainties for these receivables, which we believe to be adequate.

**16. Purchased Power and Gas Sales and Expense**

The Company records the cost of gas consumed in its power plants as fuel expense, while gas purchased from third parties, for hedging, balancing and related activities, is recorded as purchased gas expense, a component of oil and gas production and marketing expense. The Company records the actual revenue received from third parties as sales of purchased gas, a component of oil and gas production and

marketing revenue.

The cost of power purchased from third parties, for hedging, balancing and related purposes, is recorded as purchased power expense, a component of electric generation and marketing expense. The Company markets on a system basis both power generated by its plants in excess of amounts under direct contract between the plant and a third party, and power purchased from third parties.





The table below shows the relative levels and growth of power and gas hedging, balancing and related activity.

| | For the Year Ended December 31, | | |
|---|---|---|---|
| | 2000 | 1999 | 1998 |
| Sales of purchased power | $370,481 | $23,157 | $ 3,463 |
| Sales of purchased gas | 108,329 | 14,416 | 7,223 |
| Total | $478,810 | $37,573 | $10,686 |
| Purchased power expense | $358,649 | $20,681 | $ 3,129 |
| Purchased gas expense | 108,331 | 12,646 | 6,339 |
| Total | $466,980 | $33,327 | $ 9,468 |

**17. Earnings per Share**

Basic earnings per common share were computed by dividing net income by the weighted average number of common shares outstanding for the period. The dilutive effect of the potential exercise of outstanding options to purchase shares of common stock is calculated using the treasury stock method. The dilutive effect of the assumed conversion of certain trust preferred securities into the Company's common stock is based on the dilutive common share equivalents and the after tax distribution expense avoided upon conversion. The reconciliation of basic earnings per common share to diluted earnings per share is shown in the following table (in thousands except per share data). All share data has been adjusted to reflect the two-for-one stock splits effective October 7, 1999, June 8, 2000, and November 14, 2000.

| | For the Years Ended December 31, | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | 2000 | | | 1999 | | | 1998 | | |
| | Net Income | Shares | EPS | Net Income | Shares | EPS | Net Income | Shares | EPS |
| **Basic earnings per common share:** | | | | | | | | | |
| Income before extraordinary charge | $373,837 | 281,070 | $ 1.33 | $107,800 | 225,375 | $ 0.48 | $39,158 | 176,725 | $0.22 |
| Extraordinary charge net of tax benefit of $796, $793 and $441 for 2000, 1999 and 1998 respectively | 1,235 | | — | 1,150 | | (0.01) | 641 | | — |
| Net income | $372,602 | 281,070 | $ 1.33 | $106,650 | 225,375 | $ 0.47 | $38,517 | 176,725 | $0.22 |
| Common shares issuable upon exercise of stock options using treasury stock method | | 16,437 | | | 13,331 | | | 8,342 | |
| **Diluted earnings per common share:** | | | | | | | | | |
| Income before extraordinary charge and dilutive effect of certain trust preferred securities | $373,837 | 297,507 | $ 1.26 | $107,800 | 238,706 | $ 0.45 | $39,158 | 185,067 | $0.21 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Dilutive effect of certain trust preferred securities | 20,841 | 31,746 | (0.06) | — | — | — | — | — | — |
| Income before extraordinary charge | 394,678 | 329,253 | 1.20 | 107,800 | 238,706 | 0.45 | 39,158 | 185,067 | 0.21 |
| Extraordinary charge net of tax benefit of $796, $793, and $441 for 2000, 1999 and 1998 respectively | 1,235 | | (0.01) | 1,150 | | — | 641 | | — |
| Net income | $393,443 | 329,253 | $ 1.19 | $106,650 | 238,706 | $ 0.45 | $38,517 | 185,067 | $0.21 |

The Company recognized an extraordinary charge of $1.2 million (net of tax benefit of $0.8 million) in 2000, representing the write-off of deferred financing costs related to the termination of certain financing arrangements described in Note 7.

In 1999, the Company recognized an extraordinary charge of $1.2 million or $0.01 per share (net of tax benefit of $0.8 million) in April of 1999, representing the write-off of deferred financing costs related to non-





recourse project financing for the Gilroy Power Plant. The financing agreement was terminated and the outstanding balance as of April 1999 of $120.6 million was repaid.

In 1998, the Company recognized a $0.6 million extraordinary charge (net of tax benefit of $0.4 million), for the repurchase of $8.3 million of the 10 1/2% Senior Notes due 2006. The notes were redeemed at a premium plus accrued interest to the date of repurchase.

Unexercised employee stock options to purchase 786,802, 1,053,063 and 1,033,988 shares of the Company's common stock during the years ended December 31, 2000, 1999, and 1998, respectively, were not included in the computation of diluted shares outstanding because such inclusion would be anti-dilutive.

**18. Commitments and Contingencies**

*Production Royalties and Leases* — The Company is committed under numerous geothermal leases and right-of-way, easement and surface agreements. The geothermal leases generally provide for royalties based on production revenue with reductions for property taxes paid. The right-of-way, easement and surface agreements are based on flat rates and are not material. Under the terms of certain geothermal leases, prior to May, 1999, when the Company consolidated the steam field and power plant operations in Lake and Sonoma Counties in northern California ("The Geysers"), royalties accrued at rates ranging from 3% to 14% of steam and effluent revenue. Following the consolidation of operations, the royalties began to accrue as a percentage of electrical revenues. Certain properties also have net profits and overriding royalty interests ranging from approximately 1% to 28%, which are in addition to the land royalties. Most lease agreements contain clauses providing for minimum lease payments to lessors if production temporarily ceases or if production falls below a specified level.

Production royalties and lease expense for the years ended December 31, 2000, 1999 and 1998 are $32.3 million, $13.8 million and $10.7 million, respectively.

*Natural Gas Purchases* — The Company enters into gas purchase contracts of various terms with third parties to supply gas to its gas-fired cogeneration projects.

*Oil & Gas Pipeline Transportation in Canada* — To support production and marketing operations, Calpine has firm commitments in the ordinary course of business for gathering, processing and transmission services that require the Company to deliver certain minimum quantities of crude oil and liquids and natural gas to third parties or pay the corresponding tariffs

*Office and Equipment Leases* — The Company leases its corporate office and regional offices under noncancellable operating leases expiring through 2011. Future minimum lease payments under these leases are as follows (in thousands):

| | |
|---|---|
| 2001 | $ 11,453 |
| 2002 | 15,864 |
| 2003 | 15,118 |

| | |
|---|---|
| 2004 | 12,275 |
| 2005 | 10,965 |
| Thereafter | 50,279 |
| Total | $115,954 |

Lease payments are subject to adjustments for the Company's pro rata portion of annual increases or decreases in building operating costs. In 2000, 1999 and 1998 rent expense for noncancellable operating leases amounted to $6.3 million, $4.0 million and $1.8 million, respectively.





*Cogeneration Facilities Operating Leases* — The Company has entered into long-term operating leases for cogeneration facilities and combined-cycle power generating facilities, expiring through 2048. Future minimum lease payments under these leases are as follows (in thousands):

| | Initial Year | 2001 | 2002 | 2003 | 2004 | 2005 | Thereafter | Total |
|---|---|---|---|---|---|---|---|---|
| Watsonville | 1995 | $ 2,905 | $ 2,905 | $ 2,905 | $ 2,905 | $ 2,905 | $ 12,779 | $ 27,304 |
| King City | 1996 | 21,015 | 21,848 | 22,781 | 13,975 | 10,585 | 119,426 | 209,630 |
| Greenleaf | 1998 | 9,070 | 8,990 | 8,994 | 8,858 | 8,723 | 62,928 | 107,563 |
| Geysers | 1999 | 50,102 | 69,408 | 61,135 | 48,902 | 50,300 | 257,690 | 537,537 |
| KIAC | 2000 | 22,126 | 25,227 | 25,467 | 24,251 | 24,077 | 336,812 | 457,960 |
| Rumford/ Tiverton | 2000 | 21,746 | 32,940 | 32,940 | 35,365 | 44,942 | 755,292 | 923,225 |
| Pasadena | 2000 | 36,941 | 31,600 | 131,018 | 26,907 | 27,777 | 511,124 | 765,367 |
| Total | | $163,905 | $192,918 | $285,240 | $161,163 | $169,309 | $2,056,051 | $3,028,586 |

In 2000, 1999 and 1998, rent expense for cogeneration facilities operating leases amounted to $69.4 million, $33.6 million and $15.7 million, respectively. The Watsonville operating lease provides for additional contingent rents payable during the period from July through December. Contingent rent expense for 2000, 1999 and 1998 amounted to $6.8 million, $393,000 and $1.5 million, respectively.

The King City operating lease commitment is supported by $88.3 million of collateral securities consisting of investment grade and U.S. Treasury securities that mature serially in amounts equal to a portion of the semi-annual lease payment.

At December 31, 2000, the Company is under contract or letter of intent with certain companies for 228 gas and steam turbines for a total purchase price of $6.7 billion (of which $1.8 billion had been paid as of December 31, 2000).

Approximate future payments relating to these turbines are as follows (in thousands):

| | |
|---|---|
| 2001 | $1,529,184 |
| 2002 | 1,374,271 |
| 2003 | 1,406,151 |
| 2004 | 531,832 |
| 2005 | 50,522 |
| Thereafter | 5,052 |
| Total | $4,897,012 |

*Litigation*

An action was filed against Lockport Energy Associates, L.P. and the New York Public Service Commission ("NYPSC") in August 1997 by New York State Electricity and Gas Company ("NYSEG") in the Federal District Court for the Northern District of New York. NYSEG requested the Court to direct NYPSC and the Federal Energy Regulatory Commission (the "FERC") to modify contract rates to be paid to the Lockport Power Plant. In October 1997, NYPSC filed a cross-claim alleging that the FERC violated the Public Utility Regulatory Policies Act of 1978, as amended ("PURPA"), and the Federal Power Act by failing to reform the NYSEG contract that was previously approved by the NYPSC. On September 29, 2000, the New York Federal District Court dismissed NYSEG's complaint and NYPSC's cross-claim. The Court stated that FERC has no authority to alter or waive its regulations or exemptions to alter the terms of the applicable power purchase agreements and that Qualifying Facilities are entitled to the benefit of their bargain, even if at the expense of NYSEG and its ratepayers. NYSEG has filed an appeal with respect to this





decision. In any event, the Company retains the right to require The Brooklyn Union Gas Company to purchase its interest in the Lockport Power Plant for $18.9 million, less equity distributions received by the Company, at any time before December 19, 2001.

The Company is involved in various other claims and legal actions arising out of the normal course of business. The Company does not expect that the outcome of these proceedings will have a material adverse effect on the Company's financial position or results of operations.

**19. Operating Segments**

The Company is first and foremost an electric generating company. In pursuing this single business strategy, it is the Company's objective to provide approximately 25% of its fuel consumption from its own natural gas production ("equity gas"). Since the Company's oil and gas production and marketing activity has reached the quantitative criteria to be considered a reportable segment under SFAS No. 131, "Disclosures about Segments of an Enterprise and Related Information," the following represents reportable segments and their defining criteria. The Company's segments are electric generation and marketing; oil and gas production and marketing; and corporate activities and other. Electric generation and marketing includes the development, acquisition, ownership and operation of power production facilities, the sale of electricity and steam and electricity hedging and related activity. Oil and gas production includes the ownership and operation of gas fields, gathering systems and gas pipelines for internal gas consumption, third party sales and oil and gas hedging and related activity. Corporate activities and other consists primarily of financing activities and general and administrative costs. Certain costs related to company-wide functions are allocated to each segment. However, interest on corporate debt is maintained at Corporate and is not allocated to the segments.

The Company evaluates performance based upon several criteria including profits before tax. The accounting policies of the operating segments are the same as those described in Note 2 to the Consolidated Financial Statements, "Summary of Significant Accounting Policies." The financial results for the Company's operating segments have been prepared on a basis consistent with the manner in which the Company's management internally disaggregates financial information for the purposes of assisting in making internal operating decisions.





Due to the integrated nature of the business segments, estimates and judgments have been made in allocating certain revenue and expense items.

| (in thousands) | Electric Generation and Marketing | Oil and Gas Production and Marketing | Corporate and Other | Total |
|---|---|---|---|---|
| **2000** | | | | |
| Total Revenue | $2,103,729 | $ 443,173 | $ 199 | $ 2,547,101 |
| Depreciation expense | 103,291 | 119,725 | 7,771 | 230,787 |
| Interest expense | 48,582 | 25,857 | 244 | 74,683 |

| | | | | |
|---|---|---|---|---|
| Interest income | 18,751 | 771 | 20,378 | 39,900 |
| Income before taxes | 600,008 | 50,650 | (12,012) | 638,646 |
| Equity income | 24,385 | (1,289) | 1,543 | 24,639 |
| Total assets | 4,765,928 | 1,033,293 | 4,523,982 | 10,323,203 |
| Property additions | 4,167,551 | 664,911 | 29,238 | 4,861,700 |
| **1999** | | | | |
| Total Revenue | $ 821,191 | $ 156,093 | $ 6,200 | $ 983,484 |
| Depreciation expense | 60,766 | 56,142 | 17,999 | 134,907 |
| Interest expense | 17,048 | 13,381 | 72,819 | 103,248 |
| Interest income | 8,829 | — | 15,277 | 24,106 |
| Income before taxes | 259,846 | 15,673 | (99,661) | 175,858 |
| Equity income | 36,483 | 110 | — | 36,593 |
| Total assets | 2,020,146 | 610,684 | 1,770,072 | 4,400,902 |
| Property additions | 1,487,781 | 387,877 | 8,140 | 1,883,798 |
| **1998** | | | | |
| Total Revenue | $ 539,162 | $ 101,921 | $ 9,563 | $ 650,646 |
| Depreciation expense | 73,351 | 44,885 | 637 | 118,873 |
| Interest expense | 21,534 | 9,006 | 65,192 | 95,732 |
| Interest income | 8,832 | — | 3,516 | 12,348 |
| Income before taxes | 121,490 | (12,148) | (49,001) | 60,341 |
| Equity income | 25,240 | — | — | 25,240 |
| Total assets | 1,019,705 | 303,063 | 709,241 | 2,032,009 |
| Property additions | 365,957 | 121,546 | 2,991 | 490,494 |

For the years ended December 31, 2000, 1999, and 1998, there were intersegment revenues of approximately $66.5 million, $3.7 million and $0, primarily relating to the use of internally procured gas for the Company's power plants. These intersegment revenues have been netted in Total Revenue and Income before taxes in the oil and gas production and marketing reporting segment.

*Geographic Area Information*

As of December 31, 2000 the Company owned interests in 50 operating power plants in the United States. In addition, the Company had oil and gas interests in the United States and Canada. Geographic revenue and property, plant and equipment information is based on physical location of the assets at the end of each period.





| | United States | Canada | Total |
|---|---|---|---|
| **1998** | | | |
| Total Revenue | 555,948 | 94,698 | 650,646 |
| Property, plant and equipment, net | 1,094,303 | 278,016 | 1,372,319 |
| **1999** | | | |
| Total Revenue | 847,735 | 135,749 | 983,484 |
| Property, plant and equipment, net | 2,912,672 | 363,508 | 3,276,180 |
| **2000** | | | |
| Total Revenue | 2,254,542 | 292,559 | 2,547,101 |
| Property, plant and equipment, net | 7,213,444 | 765,716 | 7,979,160 |

**20. Subsequent Events**

*California Power Market*

During 2000, a combination of factors including increased volatility of natural gas prices, a significant number of facilities undergoing planned and unplanned major maintenance, and the decreased availability of energy for importation from neighboring states resulted in wholesale power prices significantly higher than historical levels. At the same time, two major California utilities that are subject to a retail rate freeze, including PG&E, have faced wholesale prices that far exceed the retail prices they are permitted to charge, resulting in a significant underrecovery of their costs. On January 16 and 17, 2001, PG&E's credit and debt ratings were lowered by Moody's and S&P to "junk" or "near junk" status. On January 30, 2001, the PX suspended operation of its "day-ahead" and "day-of" markets. On February 1, 2001, PG&E indicated that it intended to default on payments of over $1 billion due to the PX and qualifying facilities. PG&E has defaulted under its payment obligations to the Company (See Note 15).

On February 7, 2001, the Company announced the signing of a 10-year, $4.6 billion fixed-price contract with the California Department of Water Resources ("DWR") to provide electricity to the State of California. The Company committed to sell up to 1,000 megawatts of electricity, with initial deliveries of 200 megawatts starting October 1, 2001 and increasing to 1,000 megawatts by January 1, 2004. This contract will continue through 2011. The electricity will be sold directly to DWR, on a 24-hour, 7-day-a-week basis.

On February 28, 2001, the Company announced the signing of two long-term power sales contracts with the DWR. Under the terms of the first contract, a $5.2 billion, 10-year, fixed price contract, Calpine commits to sell up to 1,000 megawatts of generation. Initial deliveries are scheduled to begin July 1, 2001 with 200 megawatts and increase to 1,000 megawatts by as early as July 2002. Under the terms of the second contract, a 20-year contract totaling up to $3.1 billion, Calpine will supply DWR with up to 495 megawatts of peaking generation, beginning with 90 megawatts as early as August 2001, and increasing up to 495 megawatts as early as August 2002.

On March 13, 2001, the Company announced the signing of a two-month deal to provide 555 megawatts of electricity to DWR effective immediately through May 15, 2001.

On April 6, 2001, PG&E filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code. As of April 6, 2001, the Company had recorded approximately $266 million in accounts receivable with PG&E under the QF contracts, plus $69 million in notes receivable not yet due and payable. The Company is currently selling power to PG&E pursuant to long-term QF contracts, and PG&E is paying on a current basis for these purchases since its bankruptcy filing. The Company has discussed the PG&E situation with its external advisors. Based upon public statements made by PG&E since its bankruptcy filing, and the favorable pricing under Calpine's QF contracts, the Company is confident that PG&E will pay it for all past due power sales. However, the timing of any such payments cannot be predicted. The Company





recognizes that uncertainty exists with respect to the outcome of the PG&E bankruptcy, but has no reasonable basis at this time to estimate any potential loss with respect to these receivables. Therefore, the Company has not provided for a reserve against collection uncertainties for these receivables at this time. However, the Company continues to monitor this situation and will consider any additional facts as they arise.

*Other Subsequent Events*

On February 15, 2001, the Company completed a public offering of $1.15 billion of its 8 1/2% Senior Notes due 2011 ("Senior Notes due 2011"). The Senior Notes due 2011 bear interest at 8 1/2% per year, payable semi-annually on August 15 and February 15 and mature on February 15, 2011. The Senior Notes due 2011 may be redeemed at any time prior to maturity at a redemption price equal to 100% of their principal amount plus accrued and unpaid interest plus a make-whole premium.

On April 3, 2001, the Company acquired all of the common shares of WRMS Engineering, Inc. ("WRMS"), a California-based engineering and architectural firm, through a stock-for-stock exchange in which WRMS shareholders received a total of 151,176 shares of Calpine common stock. The aggregate value of the transaction is approximately $7.8 million, including the assumed indebtedness of WRMS. WRMS is expected to provide services to support c*Power, which provides highly reliable, critical power to industrial and high tech customers.

On April 11, 2001, the Company acquired the development rights from Enron North America for the 750-megawatt natural gas-fired Pastoria Energy Center planned for Kern County, California. The project was licensed by the California Energy Commission in December 2000. Construction will begin in June 2001 and commercial operation is scheduled for the summer of 2003.

On April 17, 2001, the Company acquired the development rights from Kirkland, Washington-based National Energy Systems Company for the 248-megawatt natural gas-fired Goldendale Energy Center planned for Goldendale, Washington. Energy generated from the Goldendale facility will be sold directly into the Northwest Power Pool. Construction commenced in April 2001, and energy deliveries are scheduled to

begin July 1, 2002.

On April 17, 2001, the Company acquired assets of The Bayless Companies and its partners with reserves located in the western portion of the San Juan Basin in New Mexico. Currently 35 wells produce approximately 6 million cubic feet equivalent per day ("mmcfe/d"), 96 percent of which is natural gas.

On April 19, 2001, the Company completed its merger with Encal Energy Ltd ("Encal") a Calgary, Alberta-based natural gas and petroleum exploration and development company. Encal shareholders received, in exchange for each share of Encal common stock, 0.1493 shares (called "exchangeable shares") of the Company's subsidiary, Calpine common equivalent shares of Calpine Canada Holdings Ltd. A total of 16,603,633 exchangeable shares were issued to Encal shareholders in exchange for all of the outstanding shares of Encal common stock. Each exchangeable share is exchangeable for one share of Calpine common stock. The aggregate value of the transaction was approximately US $1.1 billion, including the assumed indebtedness of Encal. This transaction was accounted for as a pooling-of-interests. With the addition of Encal's assets, which currently produce approximately 230 mmcfe per day, net of royalties, the Company's net production is expected to increase to 390 mmcfe per day in North America, enough to fuel approximately 2,300 megawatts of the Company's power fleet.

On April 16, 2001, the Company entered into an agreement to purchase 35 model 7FB and 11 model 7FA gas-fired turbines from GE Power Systems. The Company expects to take delivery of 5 turbines in 2002, with the remainder of the contract to be filled by the end of 2005. This brought the total number of gas-fired and steam turbines on order to 304 with an approximate value of $9 billion.





## 21. Quarterly Consolidated Financial Data (unaudited)

The Company's quarterly operating results have fluctuated in the past and may continue to do so in the future as a result of a number of factors, including, but not limited to, the timing and size of acquisitions, the completion of development projects, the timing and amount of curtailment of operations under the terms of certain power sales agreements, and variations in levels of production. Furthermore, the majority of capacity payments under certain of the Company's power sales agreements are received during the months of May through October.

The Company's common stock has been traded on the New York Stock Exchange since September 19, 1996. There were 1,005 common stockholders of record at December 31, 2000. No dividends were paid for the years ended December 31, 2000 and 1999. All share data has been adjusted to reflect the two-for-one stock split effective October 7, 1999, the two-for-one stock split effective June 8, 2000, and the two-for-one stock split effective November 14, 2000.

| | Quarter Ended | | | |
|---|---|---|---|---|
| | December 31, | September 30, | June 30, | March 31, |
| | (in thousands, except per share amounts) | | | |
| **2000** | | | | |
| Total revenue | $1,099,934 | $744,814 | $417,155 | $285,198 |
| Gross profit | 302,927 | 326,259 | 146,632 | 71,150 |
| Income from operations | 245,188 | 292,021 | 122,896 | 56,756 |
| Income before extraordinary charge | 134,683 | 158,545 | 59,508 | 21,101 |
| Extraordinary charge | — | 1,235 | — | — |
| Net income | $ 134,683 | $157,310 | $ 59,508 | $ 21,101 |
| Basic earnings per common share: | | | | |
| Income before extraordinary charge | $ 0.45 | $ 0.56 | $ 0.22 | $ 0.08 |
| Extraordinary charge | — | (0.01) | — | — |
| Net income | 0.45 | 0.55 | 0.22 | 0.08 |
| Diluted earnings per common share: | | | | |
| Income before extraordinary charge and dilutive effect of certain trust preferred securities | $ 0.43 | $ 0.52 | $ 0.21 | $ 0.07 |
| Dilutive effect of certain trust preferred securities | (0.03) | (0.03) | (0.01) | — |
| Income before extraordinary charge | 0.40 | 0.49 | 0.20 | 0.07 |

| | | | | |
|---|---|---|---|---|
| Extraordinary charge | — | (0.01) | — | — |
| Net income | 0.40 | 0.48 | 0.20 | 0.07 |
| Common stock price per share: | | | | |
| High | $ 52.97 | $ 52.25 | $ 35.22 | $ 30.75 |
| Low | 32.25 | 32.25 | 18.13 | 16.09 |



**CALPINE CORPORATION AND SUBSIDIARIES**

**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS (Continued)**
**For the Years Ended December 31, 2000, 1999 and 1998**

| | Quarter Ended | | | |
|---|---|---|---|---|
| | December 31, | September 30, | June 30, | March 31, |
| | (in thousands, except per share amounts) | | | |
| **1999** | | | | |
| Total revenue | $291,402 | $290,140 | $225,493 | $176,449 |
| Gross profit | 100,329 | 113,864 | 67,877 | 36,765 |
| Income from operations | 78,202 | 96,241 | 54,070 | 23,943 |
| Income before extraordinary charge | 37,666 | 46,434 | 20,727 | 2,973 |
| Extraordinary charge | — | — | 1,150 | — |
| Net income | $ 37,666 | $ 46,434 | $ 19,577 | $ 2,973 |
| Basic earnings per common share: | | | | |
| Income before extraordinary charge | $ 0.15 | $ 0.20 | $ 0.09 | $ 0.02 |
| Extraordinary charge | — | — | (0.01) | — |
| Net income | 0.15 | 0.20 | 0.08 | 0.02 |
| Diluted earnings per common share: | | | | |
| Income before extraordinary charge | $ 0.14 | $ 0.19 | $ 0.08 | $ 0.02 |
| Extraordinary charge | — | — | — | — |
| Net income | 0.14 | 0.19 | 0.08 | 0.02 |
| Common stock price per share: | | | | |
| High | $ 16.38 | $ 11.97 | $ 7.38 | $ 4.67 |
| Low | 10.63 | 6.85 | 4.39 | 3.16 |



**SCHEDULE II**

**VALUATION AND QUALIFYING ACCOUNTS**
**(In thousands)**

| Description | Balance at Beginning of Year | Charged to Expense | Deductions (1) | Balance at End of Year |
|---|---|---|---|---|
| Year Ended December 31, 2000 | | | | |
| Allowance for Doubtful Accounts | $3,646 | $13,454 | $(5,545) | $11,555 |
| Reserve for Notes Receivable | — | 4,513 | — | 4,513 |
| Year Ended December 31, 1999 | | | | |
| Allowance for Doubtful Accounts | $ 634 | $ 3,105 | $ (93) | $ 3,646 |
| Reserve for Notes Receivable | — | — | — | — |

(1) Represents write-off of accounts considered to be uncollectible, less recoveries of amounts previously written off.



**SUPPLEMENTAL OIL AND GAS DISCLOSURES**
**(Unaudited)**

**Oil and Gas Producing Activities**

The following disclosures for Calpine Corporation ("the Company") are made in accordance with Statement of Financial Accounting Standards (SFAS) No. 69, "Disclosures About Oil and Gas Producing Activities (An Amendment of FASB Statements 19, 25, 33 and 39)". Users of this information should be aware that the process of estimating quantities of proved, proved developed and proved undeveloped crude oil and natural gas reserves is very complex, requiring significant subjective decisions in the evaluation of all available geological, engineering and economic data for each reservoir. The data for a given reservoir may also change substantially over time as a result of numerous factors including, but not limited to, additional development activity, evolving production history and continual reassessment of the viability of production under varying economic conditions. Consequently, material revisions to existing reserve estimates occur from time to time. Although every reasonable effort is made to ensure that reserve estimates reported represent the most accurate assessments possible, the significance of the subjective decisions required and variances in available data for various reservoirs make these estimates generally less precise than other estimates presented in connection with financial statement disclosures.

Proved reserves represent estimated quantities of natural gas and crude oil that geological and engineering data demonstrate, with reasonable certainty, to be recoverable in future years from known reservoirs under economic and operating conditions existing at the time the estimates were made.

Proved developed reserves are proved reserves expect to be recovered, through wells and equipment in place and under operating methods being utilized at the time the estimates were made.

Proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those drilling units offsetting productive units that are reasonably certain of production when drilled. Proved reserves for other undrilled units can be claimed only where it can be demonstrated with certainty that there is continuity of production from the existing productive formation. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual tests in the area and in the same reservoir.

Estimates of proved and proved developed reserves at December 31, 2000, 1999 and 1998, were based on estimates made by Netherland, Sewell & Associates, Inc. (NS&A), independent petroleum consultants, for reserves in the United States; and Gilbert Laustsen Jung Associates, Ltd. (GLJA), and McDaniel & Associates, Ltd. (M&A), both independent petroleum consultants, for reserves in Canada.

Market prices as of each year-end were used for future sales of natural gas and crude oil. Future operating costs, production and ad valorem taxes and capital costs were based on current costs as of each year-end, with no escalation. There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting the future rates of production and timing of development expenditures. Reserve data represent estimates only and should not be construed as being exact. Moreover, the standardized measure should not be construed as the current market value of the proved oil and gas reserves or the costs that would be incurred to obtain equivalent reserves. A market value determination would include many additional factors including (a) anticipated future changes in natural gas and crude oil prices, production and development costs, (b) an allowance for return on investment, (c) the value of additional reserves, not considered proved at present, which may be recovered as a result of further exploration and development activities, and (d) other business risk.

During 2000, the Company merged with Encal Corporation. The merger was accounted for under the pooling-of-interests method; accordingly, the amounts in the following supplemental schedules are reported on a combined basis for each of the years presented.



*Capitalized Costs Relating to Oil and Gas Producing Activities*

The following table sets forth the capitalized costs relating to the Company's natural gas and crude oil producing activities (excluding pipeline and related assets) at December 31, 2000 and 1999 (in thousands):

| | 2000 | 1999 |
|---|---|---|

| | | |
|---|---|---|
| Proved properties | $1,331,572 | $ 807,475 |
| Unproved properties | 76,075 | 3,334 |
| Total | 1,407,647 | 810,809 |
| Less- Accumulated depreciation, depletion and amortization | (338,475) | (259,407) |
| Net capitalized costs | $1,069,172 | $ 551,402 |

*Costs Incurred in Oil and Gas Property Acquisition, Exploration and Development Activities*

The acquisition, exploration and development costs disclosed in the following tables are in accordance with definitions in SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies." Acquisition costs include costs incurred to purchase, lease or otherwise acquire property. Exploration costs include exploration expenses and additions to exploration wells, including those in progress. Development costs include additions to production facilities and equipment, as well as additions to development wells, including those in progress. The following table sets forth costs incurred related to the Company's oil and gas activities for the years ended December 31, 2000, 1999 and 1998 (in thousands):

| | **United States** | **Canada** | **Total** |
|---|---|---|---|
| December 31, 2000- | | | |
| Acquisition costs of properties- | | | |
| Proved | $103,140 | $307,356 | $410,496 |
| Unproved | 1,119 | 71,141 | 72,260 |
| Subtotal | 104,259 | 378,497 | 482,756 |
| Exploration costs | 3,177 | 62,469 | 65,646 |
| Development costs | 25,689 | 90,820 | 116,509 |
| Total | $133,125 | $531,786 | $664,911 |
| December 31, 1999- | | | |
| Acquisition costs of properties- | | | |
| Proved | $216,242 | $ 27,900 | $244,142 |
| Unproved | — | 6,000 | 6,000 |
| Subtotal | 216,242 | 33,900 | 250,142 |
| Exploration costs | 2,860 | 52,100 | 54,960 |
| Development costs | 975 | 81,800 | 82,775 |
| Total | $220,077 | $167,800 | $387,877 |
| December 31, 1998- | | | |
| Acquisition costs of properties- | | | |
| Proved | $ — | $ 39,800 | $ 39,800 |
| Unproved | — | 3,600 | 3,600 |
| Subtotal | — | 43,400 | 43,400 |
| Exploration costs | — | 23,000 | 23,000 |
| Development costs | 2,446 | 52,700 | 55,146 |
| Total | $ 2,446 | $119,100 | $121,546 |



*Results of Operations for Oil and Gas Producing Activities*

The following table sets forth results of operations for oil and gas producing activities (excluding pipeline and related operations) for the

years ended December 31, 2000, 1999 and 1998 (in thousands):

| | United States | Canada | Total |
|---|---|---|---|
| December 31, 2000- | | | |
| Oil and gas production revenues- | | | |
| Third-party | $ 42,685 | $308,359 | $351,044 |
| Intercompany | 62,809 | — | 62,809 |
| Total revenues | 105,494 | 308,359 | 413,853 |
| Exploration expenses, including dry hole | 1,836 | 22,148 | 23,984 |
| Production costs | 14,895 | 49,157 | 64,052 |
| Depreciation, depletion and amortization | 30,969 | 87,271 | 118,240 |
| Income before income taxes | 57,794 | 149,783 | 207,577 |
| Income tax provision | 22,540 | 68,612 | 91,152 |
| Results of operations | $ 35,254 | $ 81,171 | $116,425 |
| December 31, 1999- | | | |
| Oil and gas production revenues- | | | |
| Third-party | $ 5,243 | $140,600 | $145,843 |
| Intercompany | 3,790 | — | 3,790 |
| Total revenues | 9,033 | 140,600 | 149,633 |
| Exploration expenses, including dry hole | 278 | 13,100 | 13,378 |
| Production costs | 1,693 | 37,600 | 39,293 |
| Depreciation, depletion and amortization | 4,047 | 52,100 | 56,147 |
| Income before income taxes | 3,015 | 37,800 | 40,815 |
| Income tax provision | 1,176 | 15,100 | 16,276 |
| Results of operations | $ 1,839 | $ 22,700 | $ 24,539 |
| December 31, 1998- | | | |
| Oil and gas production revenues- | | | |
| Third-party | $ — | $ 99,200 | $ 99,200 |
| Intercompany | 4,599 | — | 4,599 |
| Total revenues | 4,599 | 99,200 | 103,799 |
| Exploration expenses, including dry hole | — | 9,800 | 9,800 |
| Production costs | 3,332 | 32,500 | 35,832 |
| Depreciation, depletion and amortization | 2,382 | 44,900 | 47,282 |
| Income before income taxes | (1,115) | 12,000 | 10,885 |
| Income tax provision | (417) | 5,400 | 4,983 |
| Results of operations | $ (698) | $ 6,600 | $ 5,902 |

The results of operations for oil and gas producing activities exclude interest charges and general corporate expenses.



*Net Proved and Proved Developed Reserve Summary*

The following table sets forth the Company's net proved and proved developed reserves at December 31 for each of the four years in the period ended December 31, 2000, and the changes in the net proved reserves for each of the three years in the period then ended as estimated by the independent petroleum consultants.

| | United States | Canada | Total |
|---|---|---|---|
| Natural gas (Bcf)(1)- | | | |
| Net proved reserves at December 31, 1997 | 8 | 331 | 339 |
| Revisions of previous estimates | 4 | 4 | 8 |
| Purchases in place | — | 41 | 41 |
| Extensions, discoveries and other additions | — | 70 | 70 |
| Sales in place | — | (27) | (27) |
| Production | (3) | (43) | (46) |
| Net proved reserves at December 31, 1998 | 9 | 376 | 385 |
| Revisions of previous estimates | (5) | (16) | (21) |
| Purchases in place | 212 | 21 | 233 |
| Extensions, discoveries and other additions | — | 109 | 109 |
| Sales in place | — | (5) | (5) |
| Production | (3) | (46) | (49) |
| Net proved reserves at December 31, 1999 | 213 | 439 | 652 |
| Revisions of previous estimates | 28 | (66) | (38) |
| Purchases in place | 97 | 148 | 245 |
| Extensions, discoveries and other additions | 21 | 78 | 99 |
| Sales in place | (1) | (10) | (11) |
| Production | (25) | (52) | (77) |
| Net proved reserves at December 31, 2000 | 333 | 537 | 870 |
| Natural gas liquids and crude oil (MBbl)(2)(3)- | | | |
| Net proved reserves at December 31, 1997 | — | 23,000 | 23,000 |
| Revisions of previous estimates | — | 1,400 | 1,400 |
| Purchases in place | — | 2,000 | 2,000 |
| Extensions, discoveries and other additions | — | 5,500 | 5,500 |
| Sales in place | — | (1,000) | (1,000) |
| Production | — | (3,800) | (3,800) |
| Net proved reserves at December 31, 1998 | — | 27,100 | 27,100 |
| Revisions of previous estimates | — | 600 | 600 |
| Purchases in place | 1,895 | 1,200 | 3,095 |
| Extensions, discoveries and other additions | — | 6,000 | 6,000 |
| Sales in place | — | (600) | (600) |
| Production | (35) | (3,900) | (3,935) |
| Net proved reserves at December 31, 1999 | 1,860 | 30,400 | 32,260 |
| Revisions of previous estimates | 89 | (170) | (81) |
| Purchases in place | 1,732 | 14,133 | 15,865 |
| Extensions, discoveries and other additions | 108 | 7,600 | 7,708 |
| Sales in place | (10) | (100) | (110) |
| Production | (240) | (5,202) | (5,442) |
| Net proved reserves at December 31, 2000 | 3,539 | 46,661 | 50,200 |



| | United States | Canada | Total |
|---|---|---|---|

| | | | |
|---|---|---|---|
| (Bcfe)(1) equivalent(4)- | | | |
| Net proved reserves at December 31, 1997 | 8 | 469 | 477 |
| Revisions of previous estimates | 4 | 13 | 17 |
| Purchases in place | — | 53 | 53 |
| Extensions, discoveries and other additions | — | 103 | 103 |
| Sales in place | — | (33) | (33) |
| Production | (3) | (66) | (69) |
| Net proved reserves at December 31, 1998 | 9 | 539 | 548 |
| Revisions of previous estimates | (6) | (13) | (19) |
| Purchases in place | 224 | 28 | 252 |
| Extensions, discoveries and other additions | — | 145 | 145 |
| Sales in place | — | (9) | (9) |
| Production | (3) | (69) | (72) |
| Net proved reserves at December 31, 1999 | 224 | 621 | 845 |
| Revisions of previous estimates | 29 | (67) | (38) |
| Purchases in place | 108 | 233 | 341 |
| Extensions, discoveries and other additions | 22 | 124 | 146 |
| Sales in place | (1) | (11) | (12) |
| Production | (27) | (84) | (111) |
| Net proved reserves at December 31, 2000 | 355 | 816 | 1,171 |
| Net proved developed reserves | | | |
| Natural gas (Bcf)(1) | | | |
| December 31, 1998 | 9 | 264 | 273 |
| December 31, 1999 | 193 | 315 | 508 |
| December 31, 2000 | 268 | 391 | 659 |
| Natural gas liquids and crude oil (MBbl)(2)(3)- | | | |
| December 31, 1998 | — | 21,700 | 21,700 |
| December 31, 1999 | 1,304 | 24,600 | 25,904 |
| December 31, 2000 | 2,567 | 32,929 | 35,496 |
| Bcf(1) equivalents(4)- | | | |
| December 31, 1998 | 9 | 394 | 403 |
| December 31, 1999 | 201 | 463 | 664 |
| December 31, 2000 | 283 | 588 | 871 |

(1) Billion cubic feet or billion cubic feet equivalent, as applicable.

(2) Thousand barrels.

(3) Includes crude oil, condensate and natural gas liquids.

(4) Natural gas liquids and crude oil volumes have been converted to equivalent gas volumes using a conversion factor of six cubic feet of gas to one barrel of natural gas liquids and crude oil.

*Standardized Measure of Discounted Future Net Cash Flows Relating to Proved Oil and Gas Reserves*

The following information has been developed utilizing procedures prescribed by SFAS No. 69 and based on natural gas and crude oil reserve and production volumes estimated by the independent petroleum consultants. This information may be useful for certain comparison purposes but should not be solely relied upon in evaluating the Company or its performance. Further, information contained in the following table should not be considered as representative of realistic assessments of future cash flows, nor should the standardized measure of discounted future net cash flows be viewed as representative of the current value of the Company.

The future cash flows presented below are based on sales prices, cost rates and statutory income tax rates in existence as of the date of the projections. It is expected that material revisions to some estimates of natural gas and crude oil reserves may occur in the future, development and production of the reserves may occur in periods other than those assumed, and actual prices realized and costs incurred may vary significantly from those used.

Management does not rely upon the following information in making investment and operating decisions. Such decisions are based upon a wide range of factors, including estimates of probable as well as proved reserves and varying price and cost assumptions considered more representative of a range of possible economic conditions that may be anticipated.

The following table sets forth the standardized measure of discounted future net cash flows from projected production of the Company's natural gas and crude oil reserves for the years ended December 31, 2000, 1999 and 1998 (in millions):

| | United States | Canada | Total |
|---|---|---|---|
| December 31, 2000 — | | | |
| Future cash inflows | $ 3,815 | $ 5,559 | $ 9,374 |
| Future production and development costs | (475) | (759) | (1,234) |
| Future net cash flows before income taxes | 3,340 | 4,800 | 8,140 |
| Future income taxes | (970) | (1,808) | (2,778) |
| Future net cash flows | 2,370 | 2,992 | 5,362 |
| Discount to present value at 10% annual rate | (1,172) | (1,112) | (2,284) |
| Standardized measure of discounted future net cash flows relating to proved gas, natural gas liquids and crude oil reserves(1) | $ 1,198 | $ 1,880 | $ 3,078 |
| December 31, 1999 — | | | |
| Future cash inflows | $ 485 | $ 1,599 | $ 2,084 |
| Future production and development costs | (137) | (436) | (573) |
| Future net cash flows before income taxes | 348 | 1,163 | 1,511 |
| Future income taxes | (56) | (350) | (406) |
| Future net cash flows | 292 | 813 | 1,105 |
| Discount to present value at 10% annual rate | (139) | (263) | (402) |
| Standardized measure of discounted future net cash flows relating to proved gas, natural gas liquids and crude oil reserves | $ 153 | $ 550 | $ 703 |
| December 31, 1998 — | | | |
| Future cash inflows | $ 13 | $ 926 | $ 939 |
| Future production and development costs | (2) | (334) | (336) |
| Future net cash flows before income taxes | 11 | 592 | 603 |
| Future income taxes | (2) | (119) | (121) |
| Future net cash flows | 9 | 473 | 482 |
| Discount to present value at 10% annual rate | (2) | (154) | (156) |
| Standardized measure of discounted future net cash flows relating to proved gas, natural gas liquids and crude oil reserves | $ 7 | $ 319 | $ 326 |

(1) Natural gas prices have declined significantly since December 31, 2000; consequently, the discounted future net cash flows would be significantly reduced if the standardized measure was calculated using more current pricing.

*Changes in Standardized Measure of Discounted Future Net Cash Flows*

The following table sets forth the changes in the standardized measure of discounted future net cash flows at December 31, 2000, 1999 and 1998 (in millions):

| | United States | Canada | Total |
|---|---|---|---|
| Balance, December 31, 1997 | $ 5 | $ 276 | $ 281 |
| Sales and transfers of gas, natural gas liquids and crude oil produced, net of production costs | (1) | (62) | (63) |
| Net changes in prices and production costs | (1) | 7 | 6 |
| Extensions, discoveries, additions and improved recovery, net of related costs | — | 75 | 75 |
| Development costs incurred | — | 32 | 32 |
| Revisions of previous quantity estimates and development costs | 3 | 9 | 12 |
| Accretion of discount | 1 | 19 | 20 |
| Net change in income taxes | (1) | (11) | (12) |
| Purchases of reserves in place | — | 43 | 43 |
| Sales of reserves in place | — | (33) | (33) |
| Changes in timing and other | 1 | (36) | (35) |
| Balance, December 31, 1998 | 7 | 319 | 326 |
| Sales and transfers of gas, natural gas liquids and crude oil produced, net of production costs | (7) | (98) | (105) |
| Net changes in prices and production costs | 1 | 243 | 244 |
| Extensions, discoveries, additions and improved recovery, net of related costs | — | 162 | 162 |
| Development costs incurred | — | 27 | 27 |
| Revisions of previous quantity estimates and development costs | (18) | (9) | (27) |
| Accretion of discount | 1 | 26 | 27 |
| Net change in income taxes | (29) | (127) | (156) |
| Purchases of reserves in place | 185 | 34 | 219 |
| Sales of reserves in place | — | (19) | (19) |
| Changes in timing and other | 13 | (8) | 5 |
| Balance, December 31, 1999 | 153 | 550 | 703 |
| Sales and transfers of gas, natural gas liquids and crude oil produced, net of production costs | (91) | (245) | (336) |
| Net changes in prices and production costs | 984 | 1,717 | 2,701 |
| Extensions, discoveries, additions and improved recovery, net of related costs | 129 | 475 | 604 |
| Development costs incurred | 8 | 25 | 33 |
| Revisions of previous quantity estimates and development costs | 148 | (215) | (67) |
| Accretion of discount | 15 | 39 | 54 |
| Net change in income taxes | (462) | (938) | (1,400) |
| Purchases of reserves in place | 492 | 603 | 1,095 |
| Sales of reserves in place | (2) | (17) | (19) |
| Changes in timing and other | (176) | (114) | (290) |
| Balance, December 31, 2000 | $1,198 | $1,880 | $ 3,078 |



**Exhibit VII.**

**Operating Segments for the Three and Six Months Ended June 30, 2001**

The Company's primary operating segments are electric generation and marketing; oil and gas production and marketing; and corporate activities and other. Power electric generation and marketing includes the development, acquisition, ownership and operation of power production facilities, the sale of electricity and steam and electricity hedging and related activity. Oil and gas production and marketing includes the ownership and operation of gas fields, gathering systems and gas pipelines for internal gas consumption, third party sales and oil and gas hedging and related activity. Corporate activities and other consists primarily of financing activities and general and administrative costs. Certain costs related to company-wide functions are allocated to each segment. However, interest on corporate debt is maintained at Corporate and is not allocated to the segments. Due to the integrated nature of the business segments, estimates and judgments have been made in allocating certain revenue and expense items. The Company evaluates performance of these operating segments based upon several criteria including profits before tax.

| | Electric Generation and Marketing | | Oil and Gas Production and Marketing | | Corporate and Other | | Total | |
|---|---|---|---|---|---|---|---|---|
| | 2001 | 2000 | 2001 | 2000 | 2001 | 2000 | 2001 | 2000 |
| For the three months ended June 30, 2001 and 2000: | | | | | | | | |
| Revenues from external customers | $1,261,705 | $346,454 | $343,012 | $69,652 | $ 8,156 | $ 1,050 | $1,612,873 | $417,156 |
| Nonrecurring merger costs | — | — | 35,606 | — | — | — | 35,606 | |
| Income before taxes | 173,584 | 108,400 | 7,381 | 12,208 | (2,151) | (19,562) | 178,814 | 101,046 |

| | Electric Generation and Marketing | | Oil and Gas Production and Marketing | | Corporate and Other | | Total | |
|---|---|---|---|---|---|---|---|---|
| | 2001 | 2000 | 2001 | 2000 | 2001 | 2000 | 2001 | 2000 |
| For the six months ended June 30, 2001 and 2000: | | | | | | | | |
| Revenues from external customers | $2,312,335 | $562,296 | $628,871 | $136,627 | $11,418 | $ 3,431 | $2,952,624 | $702,354 |
| Nonrecurring merger costs | — | — | 41,627 | — | — | — | 41,627 | |
| Income before taxes | 306,142 | 155,948 | 77,855 | 15,564 | 2,425 | (34,320) | 386,422 | 137,192 |

| | Power Generation | Oil and Gas Production | Corporate and Other | Total |
|---|---|---|---|---|
| Total assets as of June 30, 2001: | | | | |
| Total assets | $6,455,376 | $3,261,436 | $6,902,253 | $16,019,065 |

For the three and six months ended June 30, 2001 and 2000, there were intersegment revenues of approximately $39.0 million and $8.4 million and $84.9 million and $11.8 million, respectively, primarily relating to the use of internally procured gas for the Company's power plants. These intersegment revenues have been netted in revenues from external customers and income before taxes in the oil and gas production and marketing reporting segment.



**Exhibit VIII.**

**Exhibits to Form 8-K**

| Exhibit Number | Description |
|---|---|
| 23.1 | Consent of Arthur Andersen LLP, Independent Public Accountants.(*) |
| 23.2 | Consent of Ernst & Young LLP, Independent Chartered Accountants.(*) |
| 23.3 | Consent of Netherland, Sewell & Associates, Inc., Independent engineer.(*) |
| 23.4 | Consent of McDaniel & Associates Consultants, Ltd., Independent engineer.(*) |
| 23.5 | Consent of Gilbert Lausten Jung Associates, Ltd., Independent engineer.(*) |

(*) Filed herewith.



**Exhibit 23.1**

**CONSENT OF INDEPENDENT PUBLIC ACCOUNTANTS**

As independent public accountants, we hereby consent to the incorporation of our report dated April 19, 2001 included in this Form 8-K, into the Company's previously filed Registration Statement on Form S-8 (File No. 333-16529). It should be noted that we have not audited any financial statements of the Company subsequent to December 31, 2000 or performed any audit procedures subsequent to the date of our report.

ARTHUR ANDERSEN LLP

San Jose, California
September 5, 2001

**Exhibit 23.2**

**CONSENT OF INDEPENDENT CHARTERED ACCOUNTANTS**

We consent to the use of our report dated February 16, 2001 with respect to the consolidated financial statements of Encal Energy Ltd., included in the current report on Form 8-K of Calpine Corporation dated September 7, 2001 filed with the Securities and Exchange Commission in the United States. We have not audited any financial statements of Encal Energy Ltd. subsequent to December 31, 2000 nor performed any audit procedures subsequent to the date of our report.

Signed "ERNST & YOUNG LLP"

Calgary, Alberta
September 5, 2001

**Exhibit 23.3**

**CONSENT OF NETHERLAND, SEWELL & ASSOCIATES, INC.**

We hereby consent to the incorporation by reference on Form 8-K of Calpine Corporation (the "Company") and to the references to this firm for the Company's estimated domestic proved reserves contained on Form 8-K for the year ended December 31, 2000.

*/s/ NETHERLAND, SEWELL & ASSOCIATES, INC.*

Houston, Texas
August 31, 2001

**Exhibit 23.4**

**CONSENT OF McDANIEL & ASSOCIATES CONSULTANTS LTD.**

We hereby consent to the incorporation by reference on Form 8-K of Calpine Corporation (the "Company") and to the references to this firm for the Company's estimated Canadian proved reserves contained on Form 8-K for the year ended December 31, 2000.

*/s/ McDANIEL & ASSOCIATES CONSULTANTS LTD.*

Calgary, Alberta
August 31, 2001

**Exhibit 23.5**

**CONSENT OF GILBERT LAUSTSEN JUNG ASSOCIATES LTD.**

We hereby consent to the incorporation by reference on Form 8-K of Calpine Corporation (the "Company") and to the references to this firm for the Company's estimated Canadian proved reserves contained on Form 8-K for the year ended December 31, 2000.

*/s/ GILBERT LAUSTSEN JUNG ASSOCIATES LTD.*

Calgary, Alberta
August 31, 2001

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**End of Filing**