



Calpine



# 2002: Calpine Triumphs Amid Industry Turmoil

A REPORT FROM PETE CARTWRIGHT

Against a backdrop of a power industry in disarray in 2002, Calpine moved steadily toward our goal of becoming the largest, most profitable power company in North America and, ultimately, a major international power company.

The year's challenges included a weak economic climate, low electricity prices, widespread distrust of corporations and the power industry in particular, credit downgrades, and the virtual drying-up of capital markets and bank financings.

Calpine's management team began the year by reducing our construction capital expenditure program from a planned \$4 billion to \$2.5 billion. Plants already in construction moved forward, and new construction was limited to projects that had long-term power sales agreements or financings in place. This was still a major construction program—the largest in the history of the power industry—and very successful. We added 18 new plants and expanded three others, nearly doubling our capacity to approximately 19,100 megawatts. We generated 74.5 million megawatt-hours, a 71 percent increase from 2001. And we operated our facilities, including all new plants, with more than 92 percent cumulative availability.

Calpine is making a major contribution toward reducing pollution from North American power plants. Our natural gas-fired fleet is the most environmentally responsible portfolio of its kind in the country, and our



geothermal steam fields and 19 geothermal power plants rank as one of the largest renewable energy sources in the world. Our safety record in terms of lost-time accidents was outstanding—approximately 75 percent better than the industry average in 2002.<sup>1</sup>

We managed nearly one trillion cubic feet equivalent of proved natural gas reserves in the United States and Canada, and we produced about 25 percent of the gas we consumed.

In spite of very tight capital markets, we raised more than \$3 billion through financing transactions, paid off \$1.2 billion of bonds and debentures and sold approximately \$550 million of non-strategic assets at above book value in total. And we were profitable, with recurring net income of approximately \$309 million, or \$0.79 per share—lower than we'd like, but still a five-year compound annual growth rate of 34 percent.<sup>2</sup>

We've transformed Calpine from a developer to an operator and provider of services to the power industry. Since 1996, Calpine has been the leading U.S. developer of power plants. We're now a major power plant operating company with the largest fleet of modern, clean, efficient, natural gas-fired and geothermal facilities in North America. During the year, we strengthened Calpine Power Services and our technical services organizations. We offer a full complement of power plant development, construction, operations and maintenance services. We have more than 150 active projects with more than 30 customers.

We reduced staff during the year to match our revised development and construction program and to support our new operations- and customer-focused organization. At year-end, Calpine's staff was 3,350—10 percent fewer than at the end of 2001. Economies of scale have enabled Calpine to dramatically lower operating and overhead costs per megawatt-hour—an

<sup>1</sup>Incident rates are compared to the annual Bureau of Labor Statistics Standard Industrial Classification code rates for the year 2001.

<sup>2</sup>Calpine reported GAAP net income of \$118.6 million and EPS of \$0.33, resulting in a five-year compound annual growth rate of 13 percent. See footnote <sup>(1)</sup> of the Financial Highlights page for a reconciliation of GAAP to recurring earnings.

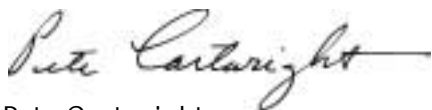


important contribution toward our commitment of being the lowest-cost power producer.

By the end of 2005, with the program currently under way, Calpine's fleet will have grown to 100 units—30,000 megawatts in 23 states, three Canadian provinces and the United Kingdom.

We've entered 2003 confident in our strategy of owning a growing fleet of the most modern power plants and producing an increasing amount of our own natural gas.

There will continue to be major challenges ahead as the new power industry matures. Calpine has the people, the resources and the commitment to not only meet those challenges, but to be the leader in bringing low-cost, clean power to residential, commercial and industrial consumers.

A handwritten signature in black ink that reads "Pete Cartwright". The signature is fluid and cursive, with a long horizontal stroke at the end.

Pete Cartwright  
Chairman, CEO and President

## CALPINE'S PRIORITIES

Calpine's clear and consistent business strategy continued to prove successful in 2002, even in a weak economic climate with depressed energy prices. Calpine has emerged a stronger company backed by the largest, most efficient and cleanest fleet of natural gas-fired and geothermal power-generating facilities in North America. Its mission and performance continue to be guided by four key priorities:

**Integrity:** Adhering to the highest standards of integrity is Calpine's principal priority. The company remains committed to ensuring safe operations for its employees, customers and neighbors; meeting or exceeding stringent environmental regulations; and strengthening its community and governmental/regulatory relations.

*Calpine met the intense pressures of 2002 without compromising its corporate integrity. The company emerged from the California energy crisis with an exemplary record and reputation of integrity and responsiveness.*

**Liquidity:** Meeting cash requirements, servicing debt and providing appropriate reserves for contingencies are the company's second-highest priority.

*Faced with credit constraints and uncertainties in the capital markets, Calpine effectively advanced its program to strengthen liquidity through several major financings, sales of non-strategic assets and reducing previously planned capital expenditures.*

**Long-Term Vision:** Calpine's third-highest priority is maintaining and strengthening its strategic, human, financial and physical resources to achieve the company's long-term goal of becoming the largest and most profitable power company in North America and a major international power company.

*In 2002, Calpine successfully transitioned from a development-focused to an operations- and customer-focused company. The company continued to deliver outstanding power plant performance, and expanded its Calpine Energy Services and Calpine Power Services organizations to maximize value for Calpine and its customers.*

**Earnings:** To enhance shareholder value, the company will continue to maximize earnings per share using good business practices, but not at the cost of compromising Calpine's integrity, liquidity or long-term vision.

*Having successfully met its three highest priorities, in 2002 Calpine generated recurring net income of approximately \$309 million.<sup>1</sup> The company's strategy of locking in or hedging two-thirds of its portfolio under long-term contracts has proven successful, despite very difficult market conditions.*

<sup>1</sup> Calpine reported GAAP net income of \$118.6 million. See footnote <sup>(n)</sup> of the Financial Highlights page for a reconciliation of GAAP to recurring earnings.

## FINANCIAL HIGHLIGHTS

For the years ended December 31, (in millions, except per share)

	1998	1999	2000	2001	2002
Revenue	\$604	\$891	\$2,375	\$6,754	\$7,458
Gross Profit	170	264	748	1,233	1,017
Net Income	39	107	369	623	119
Diluted EPS	0.21	0.45	1.18	1.80	0.33
Diluted EPS from Recurring Operations <sup>(1)</sup>	0.21	0.45	1.19	1.86	0.79
Weighted Shares Outstanding <sup>(2)</sup>	185	239	298	318	363
Total Assets	2,032	4,401	10,610	21,937	23,227
Stockholders' Equity	403	1,100	2,416	2,968	3,852
EBITDA, as adjusted <sup>(3)</sup>	283	433	1,110	1,603	1,155

<sup>(1)</sup> **Net income**

for the years ended December 31, (in millions)	1998	1999	2000	2001	2002
GAAP net income	\$39	\$107	\$369	\$623	\$119
Workforce reduction costs	–	–	–	–	12
Deferred project cost write-offs	–	–	–	–	24
Loss on sale of turbines	–	–	–	–	8
Equipment cancellation cost	–	–	–	–	288
(Gain)/loss on retirement of debt	–	1	1	(6)	(84)
(Gain) on sale of discontinued operations	–	–	–	–	(58)
Change in accounting principle	–	–	–	(1)	–
Merger expense	–	–	–	30	–
<b>Net income from recurring operations</b>	<b>\$39</b>	<b>\$108</b>	<b>\$370</b>	<b>\$646</b>	<b>\$309</b>

**Diluted EPS**

for the years ended December 31,	1998	1999	2000	2001	2002
GAAP net income	\$ 0.21	\$ 0.45	\$ 1.18	\$ 1.80	\$ 0.33
Workforce reduction costs	–	–	–	–	0.03
Deferred project cost write-offs	–	–	–	–	0.06
Loss on sale of turbines	–	–	–	–	0.02
Equipment cancellation cost	–	–	–	–	0.69
(Gain)/loss on retirement of debt	–	–	0.01	(0.02)	(0.20)
(Gain) on sale of discontinued operations	–	–	–	–	(0.14)
Change in accounting principle	–	–	–	–	–
Merger expense	–	–	–	0.08	–
<b>Net income from recurring operations</b>	<b>\$ 0.21</b>	<b>\$ 0.45</b>	<b>\$ 1.19</b>	<b>\$ 1.86</b>	<b>\$ 0.79</b>

<sup>(2)</sup> Before dilutive effect of certain convertible securities

<sup>(3)</sup> This non-GAAP measure is presented not as a measure of operating results, but rather as a measure of the company's ability to service debt. It should not be construed as an alternative to either (i) income from operations or (ii) cash flows from operating activities. It 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 expense, plus depreciation, depletion and amortization, plus distributions on trust preferred securities. The interest, tax and depreciation and amortization components of discontinued operations are added back in calculating EBITDA, as adjusted.



## CORPORATE INFORMATION

### BOARD OF DIRECTORS

Peter Cartwright  
Chairman, Chief Executive Officer  
and President

Ann B. Curtis  
Vice Chairman, Executive Vice  
President and Corporate Secretary

Kenneth T. Derr\*  
Former Chairman and Chief  
Executive Officer, ChevronTexaco  
Corporation  
Former Chairman, American  
Petroleum Institute

Jeffrey E. Garten\*  
*Chair, Compensation Committee*  
Dean, Yale School of  
Management

Gerald Greenwald\*  
Former Chairman and Chief  
Executive Officer, UAL  
Corporation  
Managing Partner, Greenbriar  
Equity Group

Susan C. Schwab\*  
*Chair, Nominating and  
Governance Committee*  
Dean, School of Public Affairs,  
University of Maryland

George J. Stathakis  
Senior Advisor to Calpine  
Chief Executive Officer, George J.  
Stathakis & Associates  
Former Executive, General Electric  
Company

John O. Wilson\*  
*Chair, Audit Committee*  
Former Executive Vice President  
and Chief Economist, Bank of  
America

\* indicates independent director

### OFFICERS

Peter Cartwright

Ann B. Curtis

Bulent A. Berilgen  
Executive Vice President and  
President, Calpine Fuels Company

Lisa M. Bodensteiner  
Executive Vice President and  
General Counsel

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

Robert D. Kelly  
Executive Vice President,  
Chief Financial Officer and  
President, Calpine Finance  
Company

E. James Macias  
Executive Vice President

Thomas R. Mason  
Executive Vice President and  
President, Calpine Power  
Company

Eric N. Pryor  
Senior Vice President,  
Deputy Chief Financial Officer and  
Corporate Risk Officer

Ron A. Walter  
Executive Vice President

### CORPORATE DATA

Stock Transfer Agent and Registrar  
EquiServe Trust Company, N.A.  
P.O. Box 43081  
Providence, RI 02940-3081  
Stockholder inquiries:  
816.843.4299  
Hearing-impaired: 800.952.9245  
www.equiserve.com

SEC Report  
If you would like a copy of  
Calpine's 2002 Annual Report on  
Form 10-K filed with the Securities  
and Exchange Commission,  
please contact Investor Relations at  
800.359.5115, ext. 2355,  
or by e-mail at investor-  
relations@calpine.com.

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Corporate Auditor  
Deloitte & Touche LLP  
225 West Santa Clara Street,  
Suite 600  
San Jose, CA 95113

Annual Meeting  
The annual meeting of the stock-  
holders of Calpine Corporation  
will be held May 28, 2003, at  
10 a.m., at Seascape Resort, One  
Seascape Resort Drive, Aptos,  
CA 95003.

Stock Listing  
New York Stock Exchange symbol:  
CPN

Calpine Foundation  
50 West San Fernando Street  
San Jose, CA 95113  
408.995.5115, ext. 1180  
foundation@calpine.com  
www.calpinefoundation.org

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

**Form 10-K**

(Mark One)

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

For the fiscal year ended December 31, 2002

or

- TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF  
THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number 1-12079

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**Calpine Corporation**

*(A Delaware Corporation)*

**I.R.S. Employer Identification No. 77-0212977**

**50 West San Fernando Street**

**San Jose, California 95113**

**Telephone: (408) 995-5115**

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

**Calpine Corporation Common Stock, \$.001 Par Value Registered on the New York Stock Exchange**

**Securities registered pursuant to Section 12(g) of the Act: None**

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

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

Indicate by check mark whether the registrant is an accelerated filer (as defined in Rule 12b-2 of the Securities Exchange Act). Yes  No

Aggregate market value of the common equity held by non-affiliates of the registrant as of June 28, 2002, the last business day of the registrant's most recently completed second fiscal quarter: approximately \$2.6 billion. Common stock outstanding as of March 26, 2003: 381,168,410 shares.

**DOCUMENTS INCORPORATED BY REFERENCE.**

Portions of the documents listed below have been incorporated by reference into the indicated parts of this report, as specified in the responses to the item numbers involved.

- (1) Designated portions of the Proxy Statement relating to the  
2003 Annual Meeting of Shareholders ..... Part III (Items 10, 11, 12 and 13)
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**FORM 10-K  
ANNUAL REPORT  
For the Year Ended December 31, 2002**

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## PART I

### Item 1. Business

*In addition to historical information, this report contains forward-looking statements. Such statements include those concerning Calpine Corporation's ("the Company's") expected financial performance and its strategic and operational plans, as well as all assumptions, expectations, predictions, intentions or beliefs about future events. You are cautioned that any such forward-looking statements are not guarantees of future performance and involve a number of risks and uncertainties that could cause actual results to differ materially from the forward-looking statements such as, but not limited to, (i) the timing and extent of deregulation of energy markets and the rules and regulations adopted on a transitional basis with respect thereto, (ii) the timing and extent of changes in commodity prices for energy, particularly natural gas and electricity, (iii) commercial operations of new plants that may be delayed or prevented because of various development and construction risks, such as a failure to obtain the necessary permits to operate, failure of third-party contractors to perform their contractual obligations or failure to obtain financing on acceptable terms, (iv) unscheduled outages of operating plants, (v) unseasonable weather patterns that produce reduced demand for power, (vi) systemic economic slowdowns, which can adversely affect consumption of power by businesses and consumers, (vii) cost estimates are preliminary and actual costs may be higher than estimated, (viii) a competitor's development of lower-cost generating gas-fired power plants, (ix) risks associated with marketing and selling power from power plants in the evolving energy market, (x) the successful exploitation of an oil or gas resource that ultimately depends upon the geology of the resource, the total amount and costs to develop recoverable reserves, and legal title, regulatory, gas administration, marketing and operational factors relating to the extraction of natural gas, (xi) the effects on the Company's business resulting from reduced liquidity in the trading and power industry, (xii) the Company's ability to access the capital markets on attractive terms, (xiii) sources and uses of cash are estimates based on current expectations; actual sources may be lower and actual uses may be higher than estimated, (xiv) the direct or indirect effects on the Company's business of a lowering of its credit rating (or actions it may take in response to changing credit rating criteria), including, increased collateral requirements, refusal by the Company's current or potential counter parties to enter into transactions with it and its inability to obtain credit or capital in desired amounts or on favorable terms, (xv) possible future claims, litigation and enforcement actions pertaining to the foregoing or (xvi) other risks as identified herein. All information set forth in this filing is as of March 31, 2003, and Calpine undertakes no duty to update this information. Readers should carefully review the "Risk Factors" section below.*

We file annual, quarterly and periodic reports, proxy statements and other information with the SEC. You may obtain and copy any document we file with the SEC at the SEC's public reference rooms in Washington, D.C., Chicago, Illinois and New York, New York. You may obtain information on the operation of the SEC's public reference facilities by calling the SEC at 1-800-SEC-0330. You can request copies of these documents, upon payment of a duplicating fee, by writing to the SEC at its principal office at 450 Fifth Street, N.W., Washington, D.C. 20549-1004. Our SEC filings are also accessible through the Internet at the SEC's website at <http://www.sec.gov>.

Our reports on Forms 10-K, 10-Q and 8-K are available for download, free of charge, as soon as reasonably practicable, at our website at [www.calpine.com](http://www.calpine.com). The content of our website is not a part of this report. You may request a copy of our SEC filings, at no cost to you, by writing or telephoning us at: Calpine Corporation, 50 West San Fernando Street, San Jose, California 95113, attention: Lisa M. Bodensteiner, Assistant Secretary, telephone: (408) 995-5115. We will not send exhibits to the documents, unless the exhibits are specifically requested and you pay our fee for duplication and delivery.

### OVERVIEW

We are a leading North American power company engaged in the development, construction, ownership and operation of power generation facilities and the sale of electricity predominantly in the United States, but also in Canada and the United Kingdom. We focus on two efficient and clean types of power generation technologies, natural gas-fired combustion turbine and geothermal. We currently lease and operate the largest fleet of geothermal power plants in the world, and have brought on-line 15,780 megawatts ("mw") of new,

clean burning natural gas power plants in the past three years. We have a proven track record in the development of new power facilities and may make acquisitions as opportunities arise. We also have in place an experienced gas production and management team to give us a broad range of fuel sourcing options, and we own nearly 1.0 trillion cubic feet equivalent of proved natural gas reserves located in Alberta, Canada as well as in the Sacramento Basin, Rockies and Gulf Coast regions of the United States. We are currently capable of producing over 270 million cubic feet equivalent of natural gas per day.

Currently, we own interests in 82 power plants having a net capacity of 19,319 mw. We also have 18 gas-fired projects and 3 project expansions currently under construction having a net capacity of 10,702 mw. The completion of the new projects currently under construction would give us interests in 100 power plants located in 23 states, 3 Canadian provinces and the United Kingdom, having a net capacity of 30,021 mw. Of this total generating capacity, 97% will be attributable to gas-fired facilities and 3% will be attributable to geothermal facilities.

Calpine Energy Services (“CES”) provides the trading and risk management services needed to schedule power sales and to make sure fuel is delivered to the power plants on time to meet delivery requirements and to optimize the value of our power and gas assets. CES is focused on managing the value of our physical power generation and gas production assets.

Complementing CES’s activities, we have recently reorganized our sales and marketing organization to better meet the needs of our growing list of wholesale and large retail customers. We focus our sales activities on load serving entities such as local utilities, municipalities, and cooperatives, as well as on large-scale end users such as industrial and commercial companies. As a general goal, we seek to have 65% of our available capacity sold under long-term contracts or hedged by our risk management group. Currently we have approximately 60% of our available capacity sold for 2003.

We also continue to strengthen our system operations management and information technology capabilities to enhance the economic performance of our portfolio of assets in our major markets and to provide load-following and other ancillary services to our customers. These operational optimization systems, combined with our sales, marketing and risk management capabilities, enable us to add value to traditional commodity products in a way that not all competitors can match.

Our construction organization has assembled what we believe to be the best-in-industry team of construction management professionals to ensure that our projects are built using our standard design specifications reflecting our exacting operational standards. We have established strategic alliances with leading equipment manufacturers for gas turbine generators, steam turbine generators and heat recovery steam generators and other key equipment. We will continue to leverage these capabilities and relationships to assure that our power plants are completed on time and are the best built and lowest cost energy facilities possible.

With a vision of enhancing the performance of our modern portfolio of gas-fired power plants and lowering our replacement parts maintenance costs, we have fostered the development of our wholly-owned subsidiary, Power Systems Manufacturing (“PSM”), to design and manufacture high performance combustion system and turbine blade parts. PSM also provides high quality turbine replacement parts to the industry.

We have recently established Calpine Power Services (“CPS”) to offer the unique skills that we have honed in building and operating our own power plants to third party customers. We are now selling, and have received contracts for, various engineering, procurement, construction management, plant commissioning, operations, and maintenance services through CPS.

As we build the nation’s most modern and efficient portfolio of gas-fired generation assets and establish the low-cost position, our integrated operations and skill sets have allowed us to weather the recent downturn in the North American energy industry. We have the flexibility to adapt to fundamental market changes. Specifically, we responded to the market downturn by reducing capital expenditures, selling or monetizing various gas, power, and contractual assets, restructuring our equipment procurement obligations, and reorganizing to reflect our transition from a development focused company to an operations focused company. These efforts have allowed us to cut costs and raise capital while positioning ourselves to continue our quest to be the largest and most profitable power company in North America.

## THE MARKET

The electric power industry represents one of the largest industries in the United States and impacts nearly every aspect of our economy, with an estimated end-user market of nearly \$250 billion of electricity sales in 2002 based on information published by the Energy Information Administration of the Department of Energy (“EIA”). Historically, the power generation industry has been largely characterized by electric utility monopolies producing electricity from old, inefficient, high-cost generating facilities selling to a captive customer base. However, industry trends and regulatory initiatives have transformed some markets into more competitive grounds where load-serving entities and end-users may purchase electricity from a variety of suppliers, including independent power producers, power marketers, regulated public utilities and others. For the past decade, the power industry has been deregulated at the wholesale level allowing generators to sell directly to the load serving entities, such as public utilities, municipalities and electric cooperatives. Although industry trends and regulatory initiatives aimed at further deregulation have slowed, the power industry continues to transform into a more competitive market.

The North American Electric Reliability Council (“NERC”) estimates that in the United States, peak (summer) electric demand in 2002 totaled approximately 710,000 mw, while summer generating capacity in 2002 totaled approximately 830,000 mw, creating a peak summer reserve margin of 120,000 mw, or 16.9%. Historically, utility reserve margins have been targeted to be 15-20% above peak demand to provide for load forecasting errors, scheduled and unscheduled plant outages and local area grid protection. Some regions have margins well in excess of the 15-20% target range, while other regions remain short of ideal reserve margins. The estimated 120,000 mw of reserve margin in 2002 compares to an estimated 96,000 mw in 2001. The increase is due in large part to the start-up of new low-cost, clean-burning, gas-fired power plants. The United States market consists of regional electric markets not all of which are effectively interconnected, so reserve margins vary from region to region.

Even though most new power plants are fueled by natural gas, the majority of power generated in the U.S. is still produced by coal and nuclear power plants. The EIA has estimated that approximately 50% of the electricity generated in the U.S. is fueled by coal, 20% by nuclear sources, 19% by natural gas, 7% by hydro, and 4% from fuel oil and other sources. As regulations continue to evolve, many of the current coal plants will likely be faced with installing a significant amount of costly emission control devices. This activity could cause some of the oldest and dirtiest coal plants to be retired, thereby allowing a greater proportion of power to be produced by cleaner natural gas-fired generation.

Although we have seen power supplies increase and higher reserve margins in the last two years, there has also been an unprecedented series of events that have undermined the industry’s progress. Industry turmoil has included the financial decline of major industry players, the demise of speculative energy trading due to the exit of numerous companies from trading activities and a decrease in liquidity in the energy trading markets, the ineffective execution of deregulation in California, and a general lessening of enthusiasm for investing in energy companies. In 2002, this loss of confidence in energy companies coincided with an economic slowdown, a decline in industrial demand growth, and historically mild weather to create a significant decline in energy prices and significant tightening in credit availability.

However, we believe that trends in market fundamentals are beginning to self-correct. Based on strength in residential and commercial demand, overall consumption of electricity was estimated to have grown at slightly above 4% in 2002, compared to the annual historical growth rate of about 2.5%. Growth in supply is diminishing with many developers canceling, or delaying, their projects as a result of current market conditions. The supply and demand balance in the natural gas industry has become strained with gas prices rising to over \$6 per million btu (“mmbtu”) in the first quarter of 2003, compared to an average of \$3 per mmbtu in 2002. In addition, capital market participants are slowly making progress in restructuring their portfolios, thereby stabilizing financial pressures on the industry. Overall, we expect the market to continue these trends and work through the current oversupply of power in several regions within the next few years. As the market improves, we expect to see spark spreads improve and capital markets regain their interest in helping to repower America with clean, highly efficient energy technologies.

## STRATEGY

Our vision is to become North America's largest and most profitable power company and ultimately become a major worldwide power company. In achieving our corporate strategic objectives, the number one priority for our company is maintaining the highest level of integrity in all of our endeavors.

Our timeline to achieve our strategic objectives is flexible and will be guided by our view of market fundamentals. When necessary, we will slow or delay our growth activities in order to assure that our financial health is secure and our investment opportunities meet our long-term rate of return requirements.

Due to the recent industry turmoil, our policy to adapt as needed to market dynamics has led us to develop a set of near-term strategic objectives that will guide our activities until market fundamentals improve. These include:

- Enhance our liquidity position
- Strengthen the balance sheet
- Complete our current construction program
- Shift our focus from a regional development to a national operating company
- Continue to lower operating costs per megawatt hour produced
- Improve operating performance with an increasingly efficient power plant fleet
- Enhance our sales and marketing program
- Start construction of new projects only when financing is available and attractive returns are expected.

We plan on realizing our strategy to become the most profitable power company by (1) achieving the low-cost position in the industry by applying our fully integrated areas of expertise to the cost-effective development, construction, financing, fueling, and operation of the most modern and efficient power generation facilities and by achieving economies of scale in general and administrative and other support costs, and (2) enhancing the value of the power we generate in the marketplace (a) by operating our plants as a system, (b) by selling directly to load-serving entities and, to the extent allowable, to industrial customers, in each of the markets in which we participate, (c) by offering load-following and other ancillary services to our customers, and (d) by providing effective marketing, risk management and asset optimization activities through our CES organization. In limited instances, we enter into contracts for the sale or purchase of power or gas in markets where we presently do not have generation assets to establish relationships with customers and gain market experience where we expect to have generation assets in the future.

Our "system approach" refers to our ability to cluster our standardized, highly efficient power generation assets within a given energy market and selling the energy from that system of power plants, rather than using "unit specific" marketing contracts. The clustering of standardized power generation assets allows for significant economies of scale to be achieved. Specifically, construction costs, supply chain activities such as inventory and warehousing costs, labor, and fuel procurement costs can all be reduced with this approach. The choice to focus on highly efficient and clean technologies reduces our fuel costs, a major expense when operating power plants. Furthermore, our lower than market heat rate (high efficiency advantage) provides us a competitive advantage in times of rising fuel prices. Finally, utilizing our system approach in a sales contract means that we can provide power to a customer from whichever plant in the system is most economical at a given period of time. In addition, the operation of plants can be coordinated when increasing or decreasing power output throughout the day to enhance overall system efficiency, thereby enhancing the heat rate advantage already enjoyed by the plants. In total, this approach lays a foundation for a sustainable competitive cost advantage in operating our plants.

The integration of gas production, trading, and marketing activities achieves additional cost reductions while simultaneously enhancing revenues. Our fleet of natural gas burning power plants requires a large amount of gas to operate. Our fuel strategy is to produce from our own gas reserves enough fuel to provide a natural hedge against gas price volatility, while providing a secure and reliable source of fuel and lowering our

fuel costs over time. The ownership of gas provides our risk management organization with additional flexibility when structuring fixed price transactions with our customers.

Recent trends confirm that both buyers and sellers of power benefit from signing long-term power contracts and avoiding the severe volatility often seen with power prices. The trend towards signing long-term contracts is creating opportunities for companies, such as ours, that own power plants and gas reserves to negotiate directly with buyers (end users and load serving entities) that need power, thereby skipping the trading middlemen, many of whom are now exiting the market.

Our financing strategy includes an objective to achieve and maintain an investment grade credit and bond rating from the major rating agencies within the next several years. We intend to employ various approaches for extending or refinancing existing credit facilities and for financing new plants, with a goal of retaining maximum system operating flexibility. The availability of capital at attractive terms will be a key requirement to enable us to develop and construct new plants. We have adjusted to recent market conditions by taking near-term actions focused on liquidity. We have been very successful throughout 2002 and early 2003 at selling certain less strategically important assets, monetizing several contracts, establishing a Canadian income trust to raise funds based on certain of our power generation assets, buying back our debt, and raising capital with non-recourse project financing.

## COMPETITION

We are engaged in several different types of business activities each of which has its own competitive environment. To better understand the competitive landscape we face, it is helpful to look at five different groupings of business activities.

*Development and Construction.* In this activity, we face strong competition from a large number of independent power producers (“IPPs”), non-regulated subsidiaries of utilities, and increasingly from regulated utilities and large end-users of electricity. Furthermore, the regulatory and community pressures against locating a power plant at a specific site can often be substantial, causing months or years of delays. Similarly, the construction process is highly competitive as there are only a few primary suppliers of key gas turbine, steam turbine and heat recovery steam generator equipment used in a state of the art gas turbine power plant. Additionally, we have seen periods of strong competition with respect to securing the best construction personnel and contractors. Finally, the recent downturn in the market has created additional competition among developers and construction organizations in terms of maintaining control over key sites, contracts, parts, and personnel.

*Power Plant Operations.* The competitive landscape faced by our power plant operations organization consists of a patchwork of highly competitive and highly regulated market environments. This patchwork has been caused by an uneven transition to deregulated markets across the various states and provinces of North America. For example, in markets where there is open competition, our merchant capacity (that which has not been sold under a long-term contract) competes directly on a real time basis with all other sources of electricity such as nuclear, coal, oil, gas-fired, and renewable units owned by others. However, there are other markets where the local incumbent utility still predominantly uses its own supply to meet its own demand before dispatching competitively provided power. Each of these markets offers a unique and challenging competitive environment.

*Asset Acquisition and Divestiture.* The recent downturn in the electricity industry has prompted many companies to sell assets to improve their financial positions. In addition, the postponement of plans for construction of new power plants is also creating a competitive market for the sale of excess equipment. Although there is a strong buyers market at the moment, few assets are changing hands due to the gap between sellers’ and buyers’ price expectations.

*Gas Production and Operations.* Gas production is a significant component of our operations and an area that we would like to expand when market conditions are attractive. However, this market is also highly competitive and is populated by numerous participants including majors, large independents and smaller “wild cat” type exploration companies. Recently, the competition in this sector has increased due to a fundamental

shift in the supply and demand balance for gas in North America. This shift has driven gas prices higher and will likely lead to increased production activities and development of alternative supply options such as LNG or coal gasification. In the near-term, however, we expect that the market to find and produce natural gas will remain highly competitive.

*Power Sales and Marketing.* Power sales and marketing generally includes all those activities associated with identifying customers, negotiating, and selling energy and service contracts to load-serving entities and large scale end-users. Specifically, there has been a trend for trading companies that served a “middle man” role to exit the industry for financial and business model reasons. Instead, power generators are increasingly selling long-term power directly to load serving entities (utilities, municipalities, cooperatives) and large scale end-users, thereby reducing the high levels of price volatility witnessed in the industry since 2001.

## RECENT DEVELOPMENTS

*Turbine Restructuring Program* — On February 11, 2003, we announced that we entered into restructured agreements with our major gas and steam turbine manufacturers. The new agreements reduce our future capital commitments by approximately \$3.4 billion and provide greater flexibility to match equipment commitments with our revised construction and development program because we have the option to cancel existing orders for 87 gas turbines and 44 steam turbines. In recognition of probable market and capital limitations, we recorded a pre-tax charge of approximately \$207.4 million in the quarter ended December 31, 2002, which represented all costs associated with the probable cancellation of all 87 gas turbines and 44 steam turbines. In addition to the fourth quarter charge, we recorded a pre-tax charge of \$168.5 million in the first quarter of 2002 as a result of turbine order cancellations and the cancellation of certain other equipment.

*Financing* — On February 13, 2003, we completed a secondary offering of 17,034,234 Warranted Units of the Calpine Power Income Fund for gross proceeds of Cdn\$153.3 million (US\$100.2 million) in an offering in Canada (with a concurrent Rule 144A placement in the United States). The Warranted Units were sold to a syndicate of underwriters at a price of Cdn\$9.00. Each Warranted Unit consists of one Trust Unit and one-half of one Trust Unit purchase warrant. Each Warrant entitles the holder to purchase one Trust Unit at a price of Cdn\$9.00 per Trust Unit at any time on or prior December 30, 2003, after which time the Warrant will be null and void. Assuming the exercise in full of the Warrants, we will not own or control any of the outstanding Trust Units. However, we will retain our 30% subordinated interest in the Canadian power generating assets and will continue to operate and manage the Calpine Power Income Fund and the Fund assets. Accordingly, the financial results of the Fund will continue to be consolidated in our financial statements.

*Restatement of Financial Statements* — On March 3, 2003, we announced that we had determined, in consultation with our independent auditors Deloitte & Touche LLP, that two sale-leaseback transactions previously accounted for as operating leases would be recorded as financing transactions. The lease reclassifications were the result of a determination that the power contracts in place at the applicable power plants (Pasadena and Broad River), for which we had utilized the sale-leaseback transactions, have characteristics that prevent the use of operating lease treatment. The reclassification of the two sale-leasebacks to financing transactions required us to restate our financial statements for the years ended December 31, 2000 and 2001 and to adjust our previously announced unaudited financial results for the year ended December 31, 2002. For a description of the effect on our financial statements of the lease reclassifications, as well as new accounting standards that require retroactive application and other adjustments and reclassifications made in connection with the re-audit of our 2000 and 2001 financial statements conducted by Deloitte & Touche, see Note 2 to the Consolidated Financial Statements included elsewhere herein.

*Hawaii Structural Ironworkers Pension Fund v. Calpine, et al.* On March 11, 2003, a securities class action, *Hawaii Structural Ironworkers Pension Fund v. Calpine, et al.*, was filed against Calpine, its directors and certain investment banks in the California Superior Court, San Diego County. The underlying allegations in the Hawaii Structural Ironworkers Pension Fund action (“Hawaii action”) are substantially the same as those in earlier securities class action lawsuits. The Hawaii action is brought on behalf of a purported class of purchasers of our equity securities sold to public investors in our April 2002 equity offering. The Hawaii action

alleges that the Registration Statement and Prospectus filed by Calpine which became effective on April 24, 2002 contained false and misleading statements regarding our financial condition in violation of Sections 11, 12 and 15 of the Securities Act of 1933. The Hawaii action relies in part on our restatement of certain past financial results, announced on March 3, 2003, to support its allegations. The Hawaii action seeks an unspecified amount of damages, in addition to other forms of relief. We consider this lawsuit to be without merit and intend to defend vigorously against these allegations.

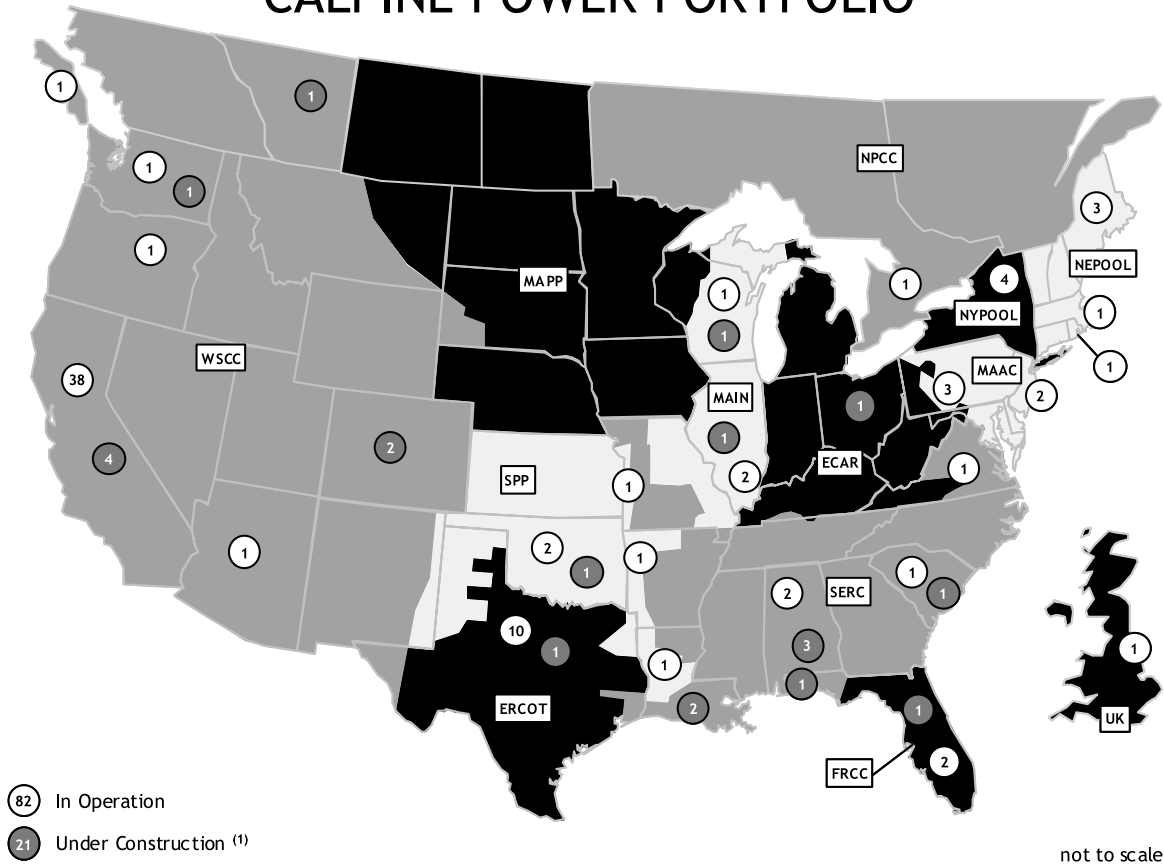
On March 26, 2003, the staff of the FERC issued a final report in an investigation the FERC had initiated on February 13, 2002 of potential manipulation of electric and natural gas prices in the western United States (the "Final Report"). The FERC staff recommended that FERC issue a show cause order to a number of companies, including Calpine, regarding certain power scheduling practices that may potentially be in violation of the CAISO's or CalPX's tariff. We believe that we did not violate these tariffs and that, to the extent that such a finding could be made, any potential liability would not be material. The Final Report also recommended that FERC modify the basis for determining potential liability in the California Refund Proceeding discussed below. See "— Risk Factors — California Power market."

On March 26, 2003, FERC also issued an order adopting many of the ALJ's findings set forth in the December 12 Certification (the "March 26 Order"). See Note 28 to the Notes to Consolidated Financial Statements for a discussion of the December 12 Certification. In addition, as a result of certain findings by the FERC staff concerning the unreliability or mis-reporting of certain reported indices for gas prices in California during the refund period, FERC ordered that the basis for calculating a party's potential refund liability be modified by substituting a gas proxy price based upon gas prices in the producing areas plus the tariff transportation rate for the California gas price indices previously adopted in the refund proceeding. At this time, we are unable to determine our potential liability under the March 26 Order. However, based upon a preliminary understanding, we believe that such liability is likely to increase from that calculated in accordance with the December 12 Certification, but we are unable to estimate the amount of such potential increase at this time.

The final outcome of this proceeding and the impact on our business is uncertain at this time.

See "— Summary of Key Activities" for 2002 developments.

DESCRIPTION OF POWER GENERATION FACILITIES  
**CALPINE POWER PORTFOLIO**



NERC Region / Country	Projects <sup>(1)</sup>	Megawatts	Market Share (NERC/UK)
WSCC	50	8,437	5%
ERCOT	11	7,057	8%
SERC	10	5,011	3%
SPP	7	2,851	5%
MAIN	5	1,658	4%
NEPOOL	5	1,236	2%
FRCC	3	858	2%
MAAC	5	756	1%
ECAR	1	700	1%
NYPOOL	4	247	1%
NPCC	1	10	0%
<b>TOTAL NERC</b>	<b>102</b>	<b>28,821</b>	<b>3.1%</b>
UK	1	1,200	1.8%
<b>TOTAL</b>	<b>103</b>	<b>30,021</b>	<b>3.0%</b>

<sup>(1)</sup> Includes three expansion projects.

At March 31, 2003, we had interests in 82 power generation facilities representing 19,319 megawatts of net capacity. Of these projects, 63 are gas-fired power plants with a net capacity of 18,469 megawatts, and 19 are geothermal power generation facilities with a net capacity of 850 megawatts. We also have 18 gas-fired projects and 3 project expansions currently under construction with a net capacity of 10,702 megawatts. Construction of advanced development projects will proceed if and when market fundamentals are sound, our return on investment criteria are expected to be met, and financing is available on attractive terms. Each of the power generation facilities currently in operation produces electricity for sale to a utility, other third-party end user, or to an intermediary such as a trading company. Thermal energy produced by the gas-fired cogeneration facilities is sold to industrial and governmental users.

The gas-fired and geothermal power generation projects in which we have an interest produce electricity and thermal energy that are sold pursuant to short-term and long-term power sales agreements or into the spot market. 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, and payment rates are typically either at fixed rates or indexed to fuel costs. Capacity payments are based on a power plant's net electrical output and/or its available capacity. Energy payments are earned for each kilowatt-hour of energy delivered, while capacity payments, under certain circumstances, are earned whether or not any electricity is scheduled by the customer and delivered.

Upon completion of our projects under construction, we will provide operating and maintenance services for 97 of the 100 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 for third parties 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 may be 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 manage a gas-fired power facility's fuel supply so that we protect the plant's spark spread — the margin between the value of the electricity sold and the cost of fuel to generate that electricity.

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. Our plan historically has been to refinance project-specific construction financing with long-term capital market financing after construction projects enter commercial operation.

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 and plants under construction as of March 31, 2003.

	Megawatts				
	Number of Plants	Baseload Capacity	With Peaking Capacity	Calpine Net Interest Baseload	Calpine Net Interest With Peaking
In operation					
Geothermal power plants . . . . .	19	850	850	850	850
Gas-fired power plants . . . . .	63	16,899	20,435	15,050	18,469
Under construction					
New facilities . . . . .	18	8,260	9,864	8,114	9,688
Expansion projects (three) . . . . .	—	757	1,014	757	1,014
Total . . . . .	<u>100</u>	<u>26,766</u>	<u>32,163</u>	<u>24,771</u>	<u>30,021</u>

### Operating Power Plants

Power Plant	Country, US State or Can. Province	Baseload Capacity (MW)	With Peaking Capacity (MW)	Calpine Interest Percentage	Calpine Net Interest Baseload (MW)	Calpine Net Interest With Peaking (MW)	Total 2002 Generation MWh
<b>Geothermal Power Plants</b>							
Sonoma County (12 plants) . . . . .	CA	512.0	512.0	100.0%	512.0	512.0	3,625,837
Lake County (2 plants) . . . . .	CA	145.0	145.0	100.0%	145.0	145.0	1,099,516
Calistoga . . . . .	CA	73.0	73.0	100.0%	73.0	73.0	578,229
Sonoma . . . . .	CA	53.0	53.0	100.0%	53.0	53.0	333,212
West Ford Flat . . . . .	CA	27.0	27.0	100.0%	27.0	27.0	215,197
Bear Canyon . . . . .	CA	20.0	20.0	100.0%	20.0	20.0	157,930
Aidlin . . . . .	CA	<u>20.0</u>	<u>20.0</u>	100.0%	<u>20.0</u>	<u>20.0</u>	<u>132,847</u>
Total Geothermal Power Plants (19) . . . . .		<u>850.0</u>	<u>850.0</u>		<u>850.0</u>	<u>850.0</u>	<u>6,142,768</u>
<b>Gas-Fired Power Plants</b>							
Saltend Energy Center . . . . .	UK	1,200.0	1,200.0	100.0%	1,200.0	1,200.0	7,901,761
Acadia Energy Center . . . . .	LA	1,080.0	1,160.0	50.0%	540.0	580.0	337,070
Freestone Energy Center . . . . .	TX	1,040.0	1,040.0	100.0%	1,040.0	1,040.0	2,999,487
Broad River Energy Center . . . . .	SC	—	840.0	100.0%	—	840.0	547,226
Delta Energy Center . . . . .	CA	818.0	840.0	100.0%	818.0	840.0	3,014,743
Baytown Energy Center . . . . .	TX	726.0	793.0	100.0%	726.0	793.0	2,933,665
Pasadena Power Plant . . . . .	TX	751.0	787.0	100.0%	751.0	787.0	4,921,397
Magic Valley Generating Station	TX	687.0	750.0	100.0%	687.0	750.0	2,290,237
Hermiston Power Project . . . . .	OR	530.0	630.0	100.0%	530.0	630.0	1,568,042
Channel Energy Center . . . . .	TX	531.0	608.0	100.0%	531.0	608.0	2,632,514
Aries Power Project . . . . .	MO	516.0	591.0	50.0%	258.0	295.5	996,501
Oneta Energy Center, Phase I . . . . .	OK	492.0	570.0	100.0%	492.0	570.0	238,364
South Point Energy Center . . . . .	AZ	520.0	530.0	100.0%	520.0	530.0	3,156,018
Los Medanos Energy Center . . . . .	CA	493.0	555.0	100.0%	493.0	555.0	3,393,912
Sutter Energy Center . . . . .	CA	516.0	547.0	100.0%	516.0	547.0	3,729,557
Lost Pines 1 Energy Center . . . . .	TX	522.0	545.0	50.0%	261.0	272.5	3,286,577
Ontelaunee Energy Center . . . . .	PA	511.0	541.0	100.0%	511.0	541.0	121,772
Decatur Energy Center, Phase I	AL	437.0	528.0	100.0%	437.0	528.0	857,307
Westbrook Energy Center . . . . .	ME	487.0	525.0	100.0%	487.0	525.0	3,951,731
Corpus Christi Energy Center . . . . .	TX	522.7	522.7	100.0%	522.7	522.7	243,265

<u>Power Plant</u>	<u>Country, US State or Can. Province</u>	<u>Baseload Capacity (MW)</u>	<u>With Peaking Capacity (MW)</u>	<u>Calpine Interest Percentage</u>	<u>Calpine Net Interest Baseload (MW)</u>	<u>Calpine Net Interest With Peaking (MW)</u>	<u>Total 2002 Generation MWh</u>
Hidalgo Energy Center . . . . .	TX	502.0	502.0	78.5%	394.1	394.1	2,022,191
Texas City Power Plant . . . . .	TX	465.0	471.0	100.0%	465.0	471.0	2,607,386
RockGen Energy Center . . . . .	WI	—	460.0	100.0%	—	460.0	2,290,237
Clear Lake Power Plant . . . . .	TX	335.0	412.0	100.0%	335.0	412.0	2,574,048
Zion Energy Center, Units 1 & 2	IL	—	300.0	100.0%	—	300.0	124,681
Rumford Power Plant . . . . .	ME	237.0	251.0	100.0%	237.0	251.0	1,840,027
Hog Bayou Energy Center . . . . .	AL	246.6	246.6	100.0%	246.6	246.6	556,217
Tiverton Power Plant . . . . .	RI	240.0	240.0	100.0%	240.0	240.0	1,689,678
Gordonsville Power Plant . . . . .	VA	233.0	238.0	50.0%	116.5	119.0	202,603
Island Cogeneration . . . . .	BC	230.0	230.0	41.5%	95.5	95.5	1,134,377
Pine Bluff Energy Center . . . . .	AR	213.3	213.3	100.0%	213.3	213.3	1,324,433
Los Esteros Critical Energy Center . . . . .	CA	—	180.0	100.0%	—	180.0	—
Morris Power Plant . . . . .	IL	155.0	177.5	86.0%	134.0	146.4	558,622
Dighton Power Plant . . . . .	MA	162.0	168.0	100.0%	162.0	168.0	580,516
Androscoggin Energy Center . . .	ME	160.0	160.0	32.3%	51.7	51.7	824,068
Auburndale Power Plant . . . . .	FL	143.0	153.0	100.0%	143.0	153.0	1,048,130
Grays Ferry Power Plant . . . . .	PA	143.0	148.0	40.0%	57.2	59.2	860,851
Gilroy Peaking Energy Center . .	CA	—	135.0	100.0%	—	135.0	63,319
Gilroy Power Plant . . . . .	CA	112.0	131.0	100.0%	112.0	131.0	890,676
Pryor Power Plant . . . . .	OK	109.0	124.0	80.0%	87.2	99.2	320,925
Sumas Power Plant . . . . .	WA	120.0	122.0	0.1%	0.1	0.1	856,360
Parlin Power Plant . . . . .	NJ	89.0	118.0	80.0%	71.2	94.4	408,247
Auburndale Peaking Energy Center . . . . .	FL	—	115.0	100.0%	—	115.0	970
King City Power Plant . . . . .	CA	103.0	115.0	100.0%	103.0	115.0	955,360
Kennedy International Airport Power Plant (“KIAC”) . . . . .	NY	95.0	105.0	100.0%	95.0	105.0	561,644
Bethpage Power Plant . . . . .	NY	52.0	53.7	100.0%	52.0	53.7	459,598
Bethpage Peaking Energy Center	NY	—	48.0	100.0%	—	48.0	79,588
Pittsburg Power Plant . . . . .	CA	64.0	71.0	100.0%	64.0	71.0	435,656
Newark Power Plant . . . . .	NJ	47.0	58.0	80.0%	37.6	46.4	406,805
Greenleaf 1 Power Plant . . . . .	CA	50.0	50.0	100.0%	50.0	50.0	406,152
Greenleaf 2 Power Plant . . . . .	CA	50.0	50.0	100.0%	50.0	50.0	359,257
Whitby Cogeneration . . . . .	ON	50.0	50.0	20.8%	10.4	10.4	340,991
King City Peaking Energy Center . . . . .	CA	—	45.0	100.0%	—	45.0	15,910
Yuba City Energy Center . . . . .	CA	—	45.0	100.0%	—	45.0	10,806
Feather River Energy Center . . .	CA	—	45.0	100.0%	—	45.0	—
Creed Energy Center . . . . .	CA	—	45.0	100.0%	—	45.0	—
Lambie Energy Center . . . . .	CA	—	45.0	100.0%	—	45.0	—
Wolfskill Energy Center . . . . .	CA	—	45.0	100.0%	—	45.0	—
Goose Haven Energy Center . . . .	CA	—	45.0	100.0%	—	45.0	—
Stony Brook Power Plant . . . . .	NY	36.0	40.0	100.0%	36.0	40.0	352,443
Watsonville Power Plant . . . . .	CA	29.0	30.0	100.0%	29.0	30.0	214,116

<u>Power Plant</u>	<u>Country, US State or Can. Province</u>	<u>Baseload Capacity (MW)</u>	<u>With Peaking Capacity (MW)</u>	<u>Calpine Interest Percentage</u>	<u>Calpine Net Interest Baseload (MW)</u>	<u>Calpine Net Interest With Peaking (MW)</u>	<u>Total 2002 Generation MWh</u>
Agnews Power Plant . . . . .	CA	26.5	28.6	100.0%	26.5	28.6	246,301
Philadelphia Water Project . . . . .	PA	22.0	23.0	66.4%	14.6	15.3	642
Total Gas-Fired Power Plants (63) . . . . .		<u>16,899.1</u>	<u>20,435.4</u>		<u>15,050.2</u>	<u>18,468.6</u>	<u>76,744,977</u>
Total Operating Power Plants (82) . . . . .		<u>17,749.1</u>	<u>21,285.4</u>		<u>15,900.2</u>	<u>19,318.6</u>	<u>82,887,745</u>
Consolidated Projects including plants with operating leases . . .		15,447.1	18,816.4		14,866.3	18,202.7	
Equity (Unconsolidated) Projects . . . . .		2,302	2,469		1,033.9	1,115.9	

**Projects Under Construction (All gas-fired)**

<u>Power Plant</u>	<u>Country, US State or Can. Province</u>	<u>Baseload Capacity (MW)</u>	<u>Peaking Capacity (MW)</u>	<u>Calpine Interest Percentage</u>	<u>Calpine Net Interest Baseload (MW)</u>	<u>Calpine Net Interest Peaking (MW)</u>
<b>Projects Under Construction</b>						
Deer Park Energy Center . . . . .	TX	773.0	1,007.0	100.0%	773.0	1,007.0
Morgan Energy Center . . . . .	AL	660.0	790.0	100.0%	660.0	790.0
Hillabee Energy Center . . . . .	AL	710.0	770.0	100.0%	710.0	770.0
Pastoria Energy Center . . . . .	CA	750.0	750.0	100.0%	750.0	750.0
Fremont Energy Center . . . . .	OH	550.0	700.0	100.0%	550.0	700.0
Columbia Energy Center . . . . .	SC	442.0	606.0	100.0%	442.0	606.0
Riverside Energy Center . . . . .	WI	518.0	602.0	100.0%	518.0	602.0
Metcalf Energy Center . . . . .	CA	556.0	602.0	100.0%	556.0	602.0
Osprey Energy Center . . . . .	FL	530.0	590.0	100.0%	530.0	590.0
Oneta Energy Center, Phase II* . . .	OK	493.0	570.0	100.0%	493.0	570.0
Washington Parish Energy Center	LA	509.0	565.0	100.0%	509.0	565.0
Carville Energy Center . . . . .	LA	522.7	522.7	100.0%	522.7	522.7
Otay Mesa Energy Center . . . . .	CA	510.0	593.0	100.0%	510.0	593.0
Rocky Mountain Energy Center . . .	CO	479.0	621.0	100.0%	479.0	621.0
Blue Spruce Energy Center . . . . .	CO	—	300.0	100.0%	—	300.0
Calgary Energy Centre . . . . .	AB	250.0	300.0	41.5%	103.8	124.5
Decatur Energy Center, Phase II*	AL	264.0	294.0	100.0%	264.0	294.0
Santa Rosa Energy Center . . . . .	FL	252.0	252.0	100.0%	252.0	252.0
Goldendale Energy Center . . . . .	WA	248.0	248.0	100.0%	248.0	248.0
Zion Energy Center Expansion, Unit 3* . . . . .	IL	—	150.0	100.0%	—	150.0
Riverview Energy Center . . . . .	CA	—	45.0	100.0%	—	45.0
Total Projects Under Construction (21) . . . . .		<u>9,016.7</u>	<u>10,877.7</u>		<u>8,870.5</u>	<u>10,702.2</u>

\* Expansion projects.

## ACQUISITIONS OF POWER PROJECTS AND PROJECTS UNDER CONSTRUCTION

We have extensive experience 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 may 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.

As indicated in the strategy section, our development and acquisition activities have been greatly scaled back, for the indefinite future, to focus on liquidity and operational priorities.

### Acquisitions

We may 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 100% ownership of facilities that offer us attractive opportunities for 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. Acquisition activity is dependent on the availability of financing on attractive terms and the expectation of returns that meet our long-term requirements.

Although our preference is to own 100% of the power plants we acquire or develop, there are situations when we take less than 100% ownership. Reasons why we may take less than a 100% interest in a power plant may include, but are not limited to: (a) our acquisitions of other independent power producers such as Cogeneration Corporation of America in 1999 and SkyGen Energy LLC in 2000 in which minority interest projects were included in the portfolio of assets owned by the acquired entities (Grays Ferry Power Plant (40% now owned by Calpine) and Androskoggin Energy Center (32.3% now owned by Calpine), respectively); (b) opportunities to co-invest with non-regulated subsidiaries of regulated electric utilities, which under PURPA are restricted to 50% ownership of cogeneration qualifying facilities — such as our investment in Gordonsville Power Plant (50% owned by Calpine and 50% owned by Edison Mission Energy, which is wholly-owned by Edison International Company); and (c) opportunities to invest in merchant power projects with partners who bring marketing, funding, permitting or other resources that add value to a project. An example of this is Acadia Energy Center in Louisiana (50% owned by Calpine and 50% owned by Cleco Midstream Resources, an affiliate of Cleco Corporation). None of our equity investment projects have nominal carrying values as a result of material recurring losses. Further, there is no history of impairment in any of these investments.

### Projects Under Construction

The development and construction of power generation projects involves numerous elements, including evaluating and selecting development opportunities, designing and engineering the project, obtaining power sales agreements in some cases, acquiring necessary land rights, permits and fuel resources, obtaining financing, procuring equipment and managing construction. We intend to focus on completing projects already in construction and starting new projects only when financing is available and attractive returns are expected.

*Deer Park Energy Center.* In March 2001, we announced plans to build, own and operate a 1,007-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 began in mid 2001. The first and second phases of the project are expected to begin commercial operation in August 2003 and June 2004, respectively.

*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 begin in July 2003.

*Hillabee Energy Center.* On February 24, 2000, we announced plans to build, own and operate the Hillabee Energy Center, a 770-megawatt, natural gas-fired cogeneration facility in Tallapoosa County, Alabama. Construction began in mid 2001, and we expect commercial operation of the facility will commence in early 2005.

*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 began in the summer of 2001, and commercial operation is scheduled to begin in mid 2005.

*Fremont Energy Center.* On May 23, 2000, we announced plans to build, own and operate the Fremont Energy Center, a 700-megawatt natural gas-fired electricity generating facility to be located near Fremont, Ohio. Commercial operation is expected to commence in the summer of 2005.

*Columbia Energy Center.* On September 25, 2001, we announced plans to construct the new 606-megawatt Columbia Energy Center, a natural gas-fired cogeneration facility located on property leased from Voridian (formerly Eastman Chemical Company) in Calhoun County, S.C. The facility will sell electricity to the wholesale power market and will supply thermal energy to Voridian. Commercial operation is expected to commence in the spring of 2004.

*Riverside Energy Center.* On December 18, 2002, we announced that construction of the Riverside Energy Center, a 602-megawatt natural gas-fired electricity generating facility had begun in Beloit, Wisconsin. We anticipate commercial operation of the facility to begin in the summer of 2004.

*Metcalf Energy Center.* On April 30, 1999, we submitted an Application for Certification with the California Energy Commission ("CEC") to build, own and operate the Metcalf Energy Center, a 602-megawatt natural gas-fired electricity generating facility located in San Jose, California. The CEC permit was approved on September 21, 2001. Construction of the facility began in June 2002, and commercial operation is anticipated to commence in December 2004.

*Osprey Energy Center.* On January 11, 2000, we announced plans to build, own and operate the Osprey Energy Center, a 590-megawatt, natural gas-fired cogeneration energy center near the city of Auburndale, Florida. Construction commenced in the fall 2001 and commercial operation of the facility is scheduled to begin in October of 2003. Upon commercial operation, the Osprey Energy Center will supply electric power to Tampa, Florida-based Seminole Electric Cooperative, Inc. ("Seminole") for a period of 16 years.

*Oneta Energy Center, Phase II.* 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 1,140-megawatt, natural gas-fired energy center under construction in Coweta, Oklahoma, southeast of Tulsa. The first 570-megawatt phase of the Oneta Energy Center commenced commercial operation in July 2002. The second 570-megawatt phase is expected to commence commercial operation in May 2003.

*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, which is anticipated to be in mid 2005.

*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 of 2003. 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.

*Otay Mesa Energy Center.* On July 10, 2001, we acquired Otay Mesa Generating Company, LLC and the associated development rights including a license from the California Energy Commission. The 593-megawatt facility is located in southern San Diego County, California. Construction began in 2001 and continues along with several permit amendments intended to optimize performance. Commercial operation is expected to begin in December 2004.

*Rocky Mountain Energy Center.* In August 2002, we commenced construction of the 621-megawatt, natural gas-fired Rocky Mountain Energy Center in Weld County, Colorado. We will sell the output of the facility to Public Service Co. of Colorado under the terms of a ten-year tolling agreement. Commercial operation of the facility is expected to commence in the spring of 2004.

*Blue Spruce Energy Center.* On August 26, 2002, we announced the completion of \$106-million non-recourse project financing for the construction of the 300-megawatt Blue Spruce Energy Center. We will sell the full output of the natural gas-fired peaking facility to Public Service Co. of Colorado under the terms of a ten-year tolling agreement. Commercial operation of the facility is expected to commence in May 2003.

*Calgary Energy Centre.* On April 20, 2000, we announced plans to construct the Calgary Energy Centre in Calgary, Alberta. Scheduled to begin commercial operation in April of 2003, the 300-megawatt, natural gas-fired, combined-cycle facility was the first independent power project announced in the Calgary area and represents our first power construction project in Canada.

*Decatur Energy Center, Phase II.* On February 2, 2000, we announced plans to build, own and operate a 822-megawatt, natural 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. Construction began in September 2000, and commercial operation for the first phase began in June 2002. Commercial operation of the second phase is expected to commence in June 2003.

*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 April of 2003.

*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 mid 2004. Energy generated by the facility will be sold directly into the Northwest Power Pool.

*Zion Energy Center Expansion, Unit 3.* The Unit 3 addition at the Zion Energy Center is a 150-megawatt simple-cycle peaking unit at the existing facility in Zion, Illinois. Construction of Unit 3 followed the completion of Units 1 & 2 and commercial operation of Unit 3 is expected to commence in June 2003.

*Riverview Energy Center.* In October 2002, construction began on this 45-megawatt project located in Antioch, California. Upon commercial operation, which is expected to commence in May of 2003, the Riverview Energy Center will supply peaking power to the California Department of Water Resources through a 10-year contract.

## OIL AND GAS PROPERTIES

In 1997, we began an equity gas strategy to diversify the gas sources for our natural gas-fired power plants by purchasing Montis Niger, Inc., a gas production and pipeline company operating primarily in the Sacramento Basin in northern California. We currently supply the majority of the fuel requirements for the

Greenleaf 1 and 2 Power Plants from these reserves. 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. The Sheridan acquisition provided the initial management team and operational infrastructure to evaluate and acquire oil and gas reserves to keep pace with our growth in gas-fired power plants. In December 1999, we added Vintage Petroleum, Inc.’s interest in the Rio Vista Gas Unit and related areas, representing primarily natural gas reserves located in the Sacramento Basin in northern California. Sheridan was merged into the Company in April 2000 and Calpine Natural Gas L.P. (“CNGLP”) was established to manage our oil and gas properties in the U.S.

The focus of the equity gas program has been on acquisitions 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. In conjunction with these efforts we acquired various gas assets and gas companies in 2001 and 2000. See Note 7 of the Notes to Consolidated Financial Statements for more information regarding the 2001 acquisitions.

In 2002, certain non-strategic divestments were completed to further focus operations on gas production and to enhance liquidity. These divestments are discussed in detail under Note 12 to the Consolidated Financial Statements.

As a result of our oil and gas acquisition, divestment and drilling program activity, equity equivalent net production from continuing operations was approximately 280 mmcf/d at December 31, 2002, enough to fuel approximately 2,400 megawatts of our power plant fleet, assuming an average capacity factor of 0.70.

## **MARKETING, HEDGING, OPTIMIZATION, AND TRADING ACTIVITIES**

Most of the electric power generated by our plants is transferred to our marketing and risk management unit, CES, which sells it to load-serving entities (e.g., utilities and end users) and to other third parties (e.g., power trading and marketing companies). Because a sufficiently liquid market does not exist for electricity financial instruments (typically, exchange and over-the-counter traded contracts that net settle rather than entail physical delivery) at most of the locations where we sell power, CES also enters into incremental physical purchase and sale transactions as part of its hedging, balancing, and optimization activities.

Any hedging, balancing, and optimization activities that we engage in are directly related to exposures that arise from our ownership and operation of power plants and gas reserves and are designed to protect or enhance our “spark spread” (the difference between our fuel cost and the revenue we receive for our electric generation). In many of these transactions CES purchases and resells power and gas in contracts with third parties.

We utilize derivatives, which are defined in Statement of Financial Accounting Standards (“SFAS”) No. 133, “Accounting for Derivative Instruments and Hedging Activities” to include many physical commodity contracts and commodity financial instruments such as exchange-traded swaps and forward contracts, to optimize the returns that we are able to achieve from our power and gas assets. From time to time we have entered into contracts considered energy trading contracts under Emerging Issues Task Force (“EITF”) Issue No. 02-3, “Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities.” However, our risk managers have low capital at risk and value at risk limits for energy trading, and our risk management policy limits, at any given time, our net sales of power to our generation capacity and limits our net purchases of gas to our fuel consumption requirements on a total portfolio basis. This model is markedly different from that of companies that engage in significant commodity trading operations that are unrelated to underlying physical assets. Derivative commodity instruments are accounted for under the requirements of SFAS No. 133. In addition, the EITF reached a consensus under EITF Issue No. 02-3 that gains and losses on derivative instruments within the scope of SFAS No. 133 should be shown net in the income statement if the derivative instruments are held for trading purposes. We adopted this standard effective July 1, 2002. See Item 7. “Management’s Discussion and Analysis — Impact of Recent Accounting Pronouncements” and Note 3 to the Consolidated Financial Statements for a discussion of the effects of adopting this standard.

Following is a discussion of the types of electricity and gas hedging, balancing, optimization, and trading activities in which we engage.

### ***Electricity Transactions***

- *Electricity hedging* transactions are entered into to reduce potential volatility in future results. An example of an electricity hedging transaction would be one in which we sell power at a fixed rate to allow us to predict the future revenues from our portfolio of generating plants. Hedging is a dynamic process; from time to time we adjust the extent to which our portfolio is hedged. An example of an electricity hedge adjusting transaction would be the purchase of power in the market to reduce the extent to which we had previously hedged our generation portfolio through fixed price power sales. To illustrate, suppose we had elected to hedge 65% of our portfolio of generation capacity for the following six months but then believed that prices for electricity were going to steadily move up during that same period. We might buy electricity on the open market to reduce our hedged position to, say, 50%. If electricity prices, do in fact increase, we might then sell electricity again to increase our hedged position back to the 65% level.
- *Electricity balancing* activities are typically short-term in nature and are done to make sure that sales commitments to deliver power are fulfilled. An example of an electricity balancing transaction would be where one of our generating plants has an unscheduled outage so we buy replacement power to deliver to a customer to meet our sales commitment.
- *Electricity optimization* activity, also generally short-term in nature, is done to maximize our profit potential by executing the most profitable alternatives in the power markets. An example of an electricity optimization transaction would be fulfilling a power sales contract with power purchases from third parties instead of generating power when the market price for power is below the cost of generation. In all cases, optimization activity is associated with the operating flexibility in our systems of power plants, natural gas assets, and gas and power contracts. That flexibility provides us with alternatives to most profitably manage our portfolio.
- *Electricity trading* activities are done with the purpose of profiting from movement in commodity prices or to transact business with customers in market areas where we do not have generating assets. An example of an electricity trading contract would be where we buy and sell electricity, typically with trading company counterparties, solely to profit from electricity price movements. We have engaged in limited activity of this type to date in terms of earnings impact. All such activity is done by CES, mostly through short-term contracts. Another example of an electricity trading contract would be one in which we transact with customers in market areas where we do not have generating assets, generally to develop market experience and customer relations in areas where we expect to have generation assets in the future. We have done a small number of such transactions to date.

### ***Natural Gas Transactions***

- *Gas hedging* transactions are also entered into to reduce potential volatility in future results. An example of a gas hedging transaction would be where we purchase gas at a fixed rate to allow us to predict the future costs of fuel for our generating plants or conversely where we enter into a financial forward contract to essentially swap floating rate (indexed) gas for fixed price gas. Similar to electricity hedging, gas hedging is a dynamic process, and from time to time we adjust the extent to which our portfolio is hedged. To illustrate, suppose we had elected to hedge 65% of our gas requirements for our generation capacity for the next six months through fixed price gas purchases but then believed that prices for gas were going to steadily decline during that same period. We might sell fixed price gas on the open market to reduce our hedged gas position to 50%. If gas prices do in fact decrease, we might then buy fixed price gas again to increase our hedged position back to the 65% level.
- *Gas balancing* activities are typically short-term in nature and are done to make sure that purchase commitments for gas are adjusted for changes in production schedules. An example of a gas balancing

transaction would be where one of our generating plants has an unscheduled outage so we sell the gas that we had purchased for that plant to a third party.

- *Gas optimization* activities are also generally short-term in nature and are done to maximize our profit potential by executing the most profitable alternatives in the gas markets. An example of gas optimization is selling our gas supply, not generating power, and fulfilling power sales contracts with power purchases from third parties, instead of generating power when market gas prices spike relative to our gas supply cost.
- *Gas trading* activities are done with the purpose of profiting from movement in commodity prices. An example of gas trading contracts would be where we buy and sell gas, typically with a trading company counterparty, solely to profit from gas price movements or where we transact with customers in market areas where we do not have fuel consumption requirements. We have engaged in a limited level of this type of activity to date. All such activity is done by CES, mostly through short-term contracts.

In some instances economic hedges may not be designated as hedges for accounting purposes. The accounting treatment of our various risk management and trading activities is governed by SFAS No. 133 and EITF Issue No. 02-3, as discussed above. An example of an economic hedge that is not a hedge for accounting purposes would be a long-term fixed price electric sales contract that economically hedges us against the risk of falling electric prices, but which for accounting purposes is exempted from derivative accounting under SFAS No. 133 as a normal sale. For a further discussion of our derivative accounting methodology, see Item 7 — “Management’s Discussion and Analysis of Financial Condition and Results of Operation — Application of Critical Accounting Policies.”

## 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, the ownership of a plant, and access to and service on the transmission grid. In most instances, public utilities that serve retail customers are subject to rate regulation by the state utility regulatory commission. The state utility regulatory commission is often primarily responsible for determining whether a public utility may recover the costs of wholesale electricity purchases or other supply-related activity through retail rates that the public utility may charge its customers. The state utility regulatory commission may, from time to time, impose restrictions or limitations on the manner in which a public utility may transact with wholesale power sellers, such as independent power 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 Public Utility Regulatory Policies Act of 1978, as amended (“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 Qualifying Facility (“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 (“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, 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. FERC regulations also permit QFs and utilities to negotiate agreements for utility purchases of power at rates lower than the utilities’ 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 facilities 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 repeal PUHCA and amend PURPA by limiting its mandatory purchase obligation to existing contracts. In light of the circumstances in California, the Pacific Gas and Electric Company (“PG&E”) bankruptcy and the Enron bankruptcy, among other events in recent years, there are a number of federal legislative and regulatory initiatives that could result in changes in how the energy markets are regulated. We do not know whether this legislation or regulatory initiatives will be adopted or, if adopted, what form they may take. We cannot provide assurance that any legislation or regulation ultimately adopted would not adversely affect our existing domestic 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 35 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 projects economics. The risks associated with using natural gas can include the need to arrange gathering, processing, extraction, blending, and storage, as well as 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.

### ***Federal Open Access Electric Transmission Regulation***

In the summer of 1996 FERC issued Orders Nos. 888 and 889 ordering the "functional unbundling" of transmission and generation assets by the transmission owning utilities subject to its jurisdiction. Under Order No. 888, the jurisdictional transmission owning utilities, and many non-jurisdictional transmission owners, were required to adopt the pro forma open access transmission tariff establishing terms of non-discriminatory transmission service, including generator interconnection service. Order No. 889 required transmission-owning utilities to publish information concerning the availability of transmission capacity and make such transmission capacity available on a non-discriminatory basis. In addition, these orders established the operational requirements of Independent System Operators ("ISO"), which are entities that have been given authority to operate the transmission assets of certain jurisdictional utilities. The interpretation and application of the requirements of Orders Nos. 888 and 889 continues to be refined through subsequent administrative proceedings at FERC. These orders have been subject to review, and have been affirmed, by the courts.

In December 1999 FERC issued Order No. 2000, which requires jurisdictional transmission-owning utilities to enter into agreements with ISOs to operate their transmission systems or join a Regional Transmission Organization ("RTO"), which would likewise control the transmission facilities in a certain region. Order No. 2000 sets forth the basic governance terms for RTOs. To date, compliance by the transmission-owning utilities has been uneven and has met with political resistance on the part of the state governments and the state public utilities commissions in some regions of the country. The impact on our business of the implementation of Order No. 2000 and the development of RTOs cannot be predicted.

In addition to its efforts in Order Nos. 888, 889, and 2000 and in creating RTOs, FERC has attempted to further refine and clarify the rights and obligations of owners and users of the interstate transmission grid in its Standard Market Design ("SMD") and Interconnection rule-making proceedings. FERC's intention under the SMD proceedings is to establish a set of standard rules, which could be adopted in the form of a revised tariff by transmission-owning utilities, addressing the manner in which transmission capacity would be allocated, how generation would be dispatched given transmission constraints, the coordination of transmission upgrades and the allocation of costs associated therewith, among other transmission-related issues. The Interconnection rule-making proceeding is intended to establish uniform procedures for generator interconnection to the transmission grid, including the allocation of costs associated with transmission system upgrades and special facilities required to interconnect the generator to the grid. Both of the SMD and Interconnection rule-making proceedings are pending currently. The timing of FERC's issuance in either of these proceedings is uncertain and has been delayed due to political resistance on the part of the state governments and the state public utilities commissions in some regions in the country. The impact on our business due to the issuance of final orders in these proceedings is uncertain and cannot be predicted at this time.

## *Western Energy Markets*

There was significant price volatility in both wholesale electricity and gas markets in the Western United States for much of calendar year 2000 and extending through the second quarter of 2001. Due to a number of factors, including drier than expected weather, which led to lower than normal hydro-electric capacity in California and the Northwestern United States, inadequate natural gas pipeline and electric generation capacity to meet higher than anticipated energy demand in the region, the inability of the California utilities to manage their exposure to such price volatility due to regulatory and financial constraints, and evolving market structures in California, prices for electricity and natural gas were much higher than anticipated. A number of federal and state investigations and proceedings were commenced to address the crisis.

There are currently a number of proceedings pending at FERC which were initiated as a direct result of the price volatility in the energy markets in the Western United States during this period. Many of these proceedings were initiated by buyers of wholesale electricity seeking refunds for purchases made during this period or the reduction of price terms in contracts entered into at this time. We have been a party to some of these proceedings. See Item 1. “Business — Risk Factors — California Power Market” and Item 3. “Legal Proceedings”. As part of certain proceedings, and as a result of its own investigations, FERC has ordered the implementation of certain measures for wholesale electricity markets in California and the Western United States, including, the implementation of price caps on the day ahead or real-time prices for electricity through September 30, 2002, and a continuing obligation of electricity generators to offer uncommitted generation capacity to the California Independent System Operator. FERC is continuing to investigate the causes of the price volatility in the Western United States during this period. It is uncertain at this time when these proceedings and investigations at FERC will conclude or what will be the final resolution thereof. See “— Risk Factors — California Power Market” below.

Other federal and state governmental entities have and continue to conduct various investigations into the causes of the price volatility in the energy markets in the Western United States during this time. It is uncertain at this time when these investigations will conclude or what the results may be. The impact on our business of the results of the investigations cannot be predicted at this time.

## *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 states 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 LDCs generally applicable tariffs do not cover the proposed transaction. LDC rates are usually subject to continuing

PUC oversight. We own and operate numerous midstream assets in a number of states where we have plants and/or oil and gas production.

### ***Regulation of Canadian Gas***

The Canadian natural gas industry is subject to extensive regulation by federal and provincial authorities. At the federal level, a party exporting gas from Canada must obtain an export license from the 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 each provincial authority before natural gas may be removed from the province, and provincial authorities 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, oil, gas liquids and natural gas, and the construction and operation of wells, fields, pipelines, various other mid stream facilities and equipment, 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, hazardous materials handling and disposal, 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 and relevant oil and gas related facilities are in compliance with federal performance standards mandated 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 wastewater and storm water discharge permits for wastewater and runoff, respectively, from certain of our facilities. We believe that, with respect to our geothermal and oil and gas operations, we are exempt from newly promulgated federal storm water requirements. We are required to maintain a spill prevention control and countermeasure plan with respect to certain of our oil and gas facilities. We believe that we are in material compliance with applicable discharge requirements of the Clean Water Act.

### ***Oil Pollution Act of 1990***

The Oil Pollution Act of 1990 (“OPA”) applies to our offshore facilities in the U.S. Gulf of Mexico regulating oil pollution prevention measures and financial responsibility requirements. We believe that we are in material compliance with applicable OPA requirements.

### ***Safe Drinking Water Act***

Part C of the Safe Water Drinking Act (“SWDA”) mandates the underground injection control (“UIC”) program. The UIC regulates the disposal of wastes by means of deep well injection. Deep well injection is a common method of disposing of saltwater, produced water and other oil and gas wastes. We believe that we are in material compliance with applicable UIC requirements of the SWDA.

### ***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 requirements under applicable California laws. Based on the exploration and production exception, many oil and gas wastes are exempt from hazardous wastes regulation under RCRA. For those wastes generated in association with the exploration and production of oil and gas which are classified as hazardous wastes, we undertake to comply with the RCRA requirements for identification and disposal. Various state environmental and safety laws also regulate the oil and gas industry. We believe that our operations are in material compliance with RCRA and all 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.

### ***Canadian Environmental, Health and Safety Regulations***

Our Canadian power projects and oil and gas operations are also subject to extensive federal, provincial and local laws and regulations adopted for the protection of the environment and to regulate land use. We believe that we are in material compliance with all applicable requirements under Canadian law related to same.

### ***Regulation of U.S. Gas***

The U.S. natural gas industry is subject to extensive regulation by federal, state and local authorities. Calpine holds onshore and offshore federal leases involving the U.S. Dept. of Interior (Bureau of Land Management, Bureau of Indian Affairs and the Minerals Management Service). At the federal level, various federal rules, regulations and procedures apply, including those issued by the U.S. Dept. of Interior as noted above, and the U.S. Dept. of Transportation (U.S. Coast Guard and Office of Pipeline Safety). At the state and local level, various agencies and commissions regulate drilling, production and midstream activities. Calpine has state and private oil and gas leases covering developed and undeveloped properties located in Arkansas, California, Colorado, Kansas, Louisiana, Mississippi, Missouri, Montana, New Mexico, Oklahoma, Texas and Wyoming. These federal, state and local authorities have various permitting, licensing and bonding requirements. Varied remedies are available for enforcement of these federal, state and local rules, regulations and procedures, including fines, penalties, revocation of permits and licenses, actions affecting the value of leases, wells or other assets, and suspension of production. As a result, there can be no assurance that we will not incur liability for fines and penalties or otherwise subject Calpine to the various remedies as are available to these federal, state and local authorities. However, we believe that we are currently in material compliance with these federal, state and local rules, regulations and procedures.

## RISK FACTORS

### *Capital Resources*

*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, 2002, our total consolidated funded debt was \$14.1 billion, our total consolidated assets were \$23.2 billion and our stockholders' equity was \$3.9 billion. Whether we will be able to meet our debt service obligations and repay, extend, or refinance our outstanding indebtedness will be dependent primarily upon the operational performance of our power generation facilities and of our oil and gas properties, movements in electric and natural gas prices over time, and our marketing and risk management activities.

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;
- limiting our ability to capitalize on business opportunities and to react to competitive pressures and adverse changes in government regulation;
- limiting our ability or increasing the costs to refinance indebtedness; and
- limiting our ability to enter into marketing, hedging, optimization and trading transactions by reducing the number of counterparties with whom we can transact as well as the volume of those transactions.

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

- incur indebtedness;
- make or purchase prepayments of indebtedness in whole or in part;
- pay dividends;
- make investments;
- lease properties;
- engage in transactions with affiliates;
- create liens;
- consolidate or merge with another entity, or allow one of our subsidiaries to do so;
- sell assets; and
- acquire facilities or other businesses.

Also, if our ownership changes, the indentures governing certain of our senior notes may require us to make an offer to purchase those senior notes. We cannot assure that we will have the financial resources necessary to purchase those senior notes in this event. If we are unable to comply with the terms of our indentures and other debt agreements, or if we fail to generate sufficient cash flow from operations, or to refinance our debt as described below, 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.

In addition, our senior notes, which are not secured, and our other senior unsecured debt are effectively subordinated to all of our secured indebtedness to the extent of the value of the assets securing such indebtedness. Our secured indebtedness includes our \$2.0 billion secured term loan and revolving working capital credit facilities, which are secured by our interests in our U.S. natural gas properties, the Saltend power plant in the United Kingdom, our equity investment in certain of our U.S. power plants, and the notes evidencing certain intercompany debt, as well as pledges of 100% of the equity in certain of Calpine's direct U.S. subsidiaries and 65% of the equity in Calpine Canada Energy Ltd., which is the direct or indirect parent company of all of our Canadian subsidiaries. Each borrowing under our total \$3.5 billion in secured revolving construction financing facilities is secured by the assets of the applicable project under construction. We have additional secured non-recourse project financings secured by the assets of the applicable project.

*We must refinance our debt maturing in 2003 and 2004.* In May 2003, our \$400.0 million and \$600.0 million secured revolving credit facilities under our \$2.0 billion secured term and revolving working capital credit facilities will mature and the \$1.0 billion secured term credit facility will mature in May 2004. Any letters of credit issued under the \$600.0 million secured revolving credit facility on or prior to May 24, 2003 can be extended for up to one year at our option so long as they expire no later than five business days prior to the maturity date of the term-loan facility. In November 2003 and 2004, respectively, our \$1.0 billion and \$2.5 billion secured revolving construction financing facilities will mature, requiring us to refinance this indebtedness. At December 31, 2002, we had \$949.6 million in funded borrowings outstanding under the secured term loan facility, and \$340.0 million in funded borrowings and \$573.9 million in letters of credit outstanding under the secured revolving credit facilities. Under our \$1.0 billion and \$2.5 billion secured revolving construction financing facilities, we had \$970.1 million and \$2,469.6 million outstanding, respectively. In addition to the debt discussed above, \$341.4 million and \$30.3 million of miscellaneous debt and capital lease obligations are maturing in 2003 and 2004, respectively. Our intent is to refinance all or a portion of such indebtedness, extend the maturity of the financing or obtain additional financing. Our ability to refinance this indebtedness will depend, in part, on events beyond our control, including the significant contraction in the availability of capital for participants in the energy sector, and actions taken by rating agencies. If we are unable to refinance this indebtedness, we may be required to further delay our construction program, sell assets or obtain additional financing. We may not be able to complete any such refinancing or asset sale, or obtain additional financing, on terms acceptable to us, or at the time needed or in the amounts required. See Item. 7 — “Management’s Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources.”

*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 (including any extension or refinancing) and the cost of the financing are dependent upon numerous factors. Access to capital (including any extension or refinancing) for participants in the energy sector, including for us, has been significantly restricted since late 2001. Other factors include:

- general economic and capital market conditions;
- conditions in energy markets;
- regulatory developments;
- credit availability from banks or other lenders for us and our industry peers, as well as the economy in general;
- 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.

We have financed our existing power generation facilities using a variety of leveraged financing structures, consisting of senior secured and unsecured indebtedness, construction financing, project financing, revolving credit facilities, term loans and lease obligations. Most of our construction costs during 2002 were 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 of December 31, 2002, we had approximately \$14.1 billion of total consolidated funded debt, consisting of \$0.9 billion of secured term debt, \$4.5 billion of secured construction/project financing, \$0.2 billion of capital lease obligations, \$6.9 billion in senior notes, \$1.2 billion in convertible senior notes, and \$0.4 billion of secured and unsecured 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 financed or leased. 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 lack of availability 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 seek to have us guarantee the indebtedness for future facilities. Guarantees render our general corporate funds vulnerable in the event of a default by the facility or related subsidiary. Additionally, certain of 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.

*Our credit ratings have been downgraded and could be downgraded further.* On December 14, 2001, Moody’s downgraded our long-term senior unsecured debt from Baa3 (its lowest investment grade rating) to Ba1 (its highest non-investment grade rating). On April 2, 2002, Moody’s further downgraded our long-term senior unsecured debt from Ba1 to B1. We remain on credit watch with negative implications at Moody’s.

On December 19, 2001, Fitch, Inc. (“Fitch”) downgraded our long-term senior unsecured debt from BBB– (its lowest investment grade rating) to BB+ (its highest non-investment grade rating). On March 12, 2002, Fitch further downgraded our long-term senior unsecured debt from BB+ to BB, and on December 9, 2002, Fitch downgraded our long-term senior unsecured debt from BB to B+.

On March 25, 2002, Standard & Poor’s downgraded our corporate credit rating from BB+ (its highest non-investment grade rating) to BB and assigned a rating of B+ to our long-term senior unsecured debt. On May 17, 2002, Standard and Poor’s issued a rating of BBB– (its lowest investment grade level) on our secured credit facilities. We remain on credit watch with negative implications at Standard and Poor’s.

Many other issuers in the power generation sector have also been downgraded by one or more of the ratings agencies during this period. Such downgrades can have a negative impact on our liquidity by reducing attractive financing opportunities and increasing the amount of collateral required by trading counterparties. We cannot assure you that Moody’s, Fitch and Standard & Poor’s will not further downgrade our credit ratings in the future. If our credit rating is downgraded, we could be required to, among other things, pay additional interest under our credit agreements, or provide additional guarantees, collateral, letters of credit or cash for credit support obligations, and it could increase our cost of capital, make our efforts to raise capital more difficult and have an adverse impact on us and our subsidiaries.

*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 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, lease payments 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 or our \$2.0 billion secured term and revolving working capital credit facilities and do not guarantee the payment of interest on or principal of such debt. The right of the holders of such debt 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, 2002, our subsidiaries had \$4.5 billion of secured construction/project financing. We may utilize project financing, when appropriate in the future, and this financing will be effectively senior to our senior notes and other senior unsecured debt.

The senior note indentures and our credit facilities impose limitations on our ability and the ability of our subsidiaries to incur additional indebtedness. However, the indentures do not limit the amount of construction/project financing that our subsidiaries may incur to finance the acquisition and development of new power generation facilities. Moreover, the senior secured credit facilities do impose certain limitations on such project financings.

### *Operations*

*Revenue may be reduced significantly upon expiration or termination of our power sales agreements.* Some of the electricity we generate from our existing portfolio is sold under long-term power sales agreements that expire at various times. We also sell power under short to intermediate (1 to 5 year) contracts. When the terms of each of these various power sales agreements expire, it is possible that the price paid to us for the generation of electricity may be reduced significantly.

*Use of derivatives can create volatility in earnings and may require significant cash collateral.* During 2002, we recognized \$26.1 million in mark-to-market gains on electric power and natural gas derivatives. Please see Item 7 — "Management's Discussion and Analysis of Financial Condition and Results of Operation Impact of Recent Accounting Pronouncements" for a detailed discussion of the accounting requirements under SFAS No. 133 and EITF 02-3. We may enter into other transactions in future periods that require us to mark various derivatives to market through earnings. The nature of the transactions that we enter into in addition to volatility of natural gas and electric power prices will determine the volatility of earnings that we may experience.

As a result, in part, of the fallout from Enron's declaration of bankruptcy on December 20, 2001, companies using derivatives have become more sensitive to the inherent risks of such transactions. Consequently, companies, including us, are requiring cash collateral for certain derivative transactions in excess of what was previously required. As of December 31, 2002, we had \$25.2 million in margin deposits with counterparties, net of deposits posted by counterparties with us, and \$106.1 million of letters of credit to support CES risk management, compared to \$345.5 million and \$236.1 million, respectively, at December 31, 2001. Movements in commodity prices as well as a reduction in our derivative activities have reduced our requirements to post collateral. Future cash collateral requirements may increase based on the extent of our involvement in derivative activities and movements in commodity prices and also based on our credit ratings.

*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, short, medium and long-term supply contracts and gas hedging transactions. 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. In addition, the focus of our CES risk management organization is to manage the "spark spread" for our portfolio of generating plants, the spread between the cost of fuel and electricity revenues, and we actively enter into hedging transactions to lock in gas costs and spark spreads. 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. Additionally, our credit rating may inhibit our ability to procure gas supply from third parties. If gas is not available, or if gas

prices increase above the level that can be recovered in electricity prices, there could be a negative impact on our results of operations.

*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
- water supply and wastewater discharge agreements
- 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 might 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.

*We have grown substantially in recent years as a result of acquisitions of interests in power generation facilities and steam fields.* The integration and consolidation of our acquisitions with our existing business requires substantial management, financial and other resources and, ultimately, our acquisitions may not be successfully integrated. In addition, as we transition from a development company to an operating company, we are not likely to continue to grow at historical rates due to acquisition activities in the near future. Although the domestic power industry is continuing to undergo consolidation and acquisition opportunities at favorable prices, we believe that we are likely to confront significant competition for those opportunities and, due to the constriction in the availability of capital resources for acquisitions and other expansion, to the extent that any opportunities are identified, we may be unable to complete the acquisitions. Conversely, to the extent we seek to divest assets, we may not be able to do so at attractive prices.

*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, unless cured, could result in losing our interest in a power generation facility.

In certain situations, 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. In recent years we have relied less and less on traditional project financing, so the risk of a financing agreement default linked to a default under a power sales agreement comes into play infrequently.

*Our power generation facilities may not operate as planned.* Upon completion of our projects currently under construction, we will operate 97 of the 100 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 2002, our gas-fired and geothermal power generation facilities operated at an average availability of approximately 92% 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.

*We cannot assure that our estimates of oil and gas reserves are accurate.* Estimates of proved oil and gas reserves and the future net cash flows attributable to those reserves are prepared by independent petroleum and geological engineers. There are numerous uncertainties inherent in estimating quantities of proved oil and gas reserves and cash flows attributable to such reserves, including factors beyond our control and that of our engineers. Reserve engineering is a subjective process of estimating underground accumulations of oil and gas that cannot be measured in an exact manner. The accuracy of an estimate of quantities of reserves, or of cash flows attributable to such reserves, is a function of the available data, assumptions regarding future oil and gas prices and expenditures for future development and exploitation activities, and of engineering and geological interpretation and judgment. Additionally, reserves and future cash flows may be subject to material downward or upward revisions, based upon production history, development and exploration activities and prices of oil and gas. Actual future production, revenue, taxes, development expenditures, operating expenses, underlying information, quantities of recoverable reserves and the value of cash flows from such reserves may vary significantly from the assumptions and underlying information set forth herein. In addition, different reserve engineers may make different estimates of reserves and cash flows based on the same available data.

*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, if material, adversely affect 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. 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.

### ***Market***

*We depend on our electricity and thermal energy customers.* Our systems of power generation facilities rely on one or more power sales agreements with one or more utilities or other customers for a substantial portion of our revenue. In addition, sales of electricity to one customer during 2002, the California Department of Water Resources (“DWR”), comprised approximately 10% of our total revenue that year. The loss of significant power sales agreements with DWR or an adverse change in DWR’s ability to pay for power delivered under our contracts 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.

*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 California Public Utilities Commission (“CPUC”) issued decisions that provide for direct access for all customers as of April 1, 1998; however, the CPUC has recently suspended direct access in California effective September 20, 2001. As a result, uncertainty exists as to the future course for direct access in California in the aftermath of the energy crisis in that state. In Texas, 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.

*Our international investments may face uncertainties.* We have investments in oil and natural gas resources and power projects in Canada in development and in operation, and an investment in a power generation facility in the U.K., and we may pursue additional international investments in the future subject to the limitations on our expansion plans due to current capital market constraints. 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.

### ***California Power Market***

*The unresolved issues arising out of the California power market could adversely affect our performance.* The volatility in the California power market from mid-2000 through mid-2001 has produced significant unanticipated results.

*California Long-Term Supply Contracts.* In 2001, California adopted legislation permitting it to issue long-term revenue bonds to fund wholesale purchases of power by the California Department of Water Resources (“DWR”). The bonds will be repaid with the proceeds of payments by retail power customers over time. CES and DWR entered into four long-term supply contracts during 2001.

In early 2002, the California Public Utilities Commission (“CPUC”) and the California Electricity Oversight Board (“EOB”) filed complaints under Section 206 of the Federal Power Act with the Federal Energy Regulatory Commission (“FERC”) alleging that the prices and terms of the long-term contracts with DWR were unjust and unreasonable and contrary to the public interest (the “206 Complaint”). The contracts entered into by CES and DWR were subject to the 206 Complaint.

On April 22, 2002, we announced that we had renegotiated CES’ long-term power contracts with DWR and settled the 206 Complaint. The Office of the Governor, the CPUC, the EOB and the Attorney General for the State of California all endorsed the renegotiated contracts and dropped all pending claims against the Company and its affiliates, including any efforts by the CPUC and the EOB to seek refunds from the Company and its affiliates through the FERC California Refund Proceedings. In connection with the renegotiation, we agreed to pay \$6 million over three years to the AG to resolve any and all possible claims. A summary of the material terms of the four DWR contracts, as renegotiated, follows:

(1) *Contract 1* provides for baseload power deliveries of 350 megawatts for 2002, 600 megawatts for 2003, and 1,000 megawatts for 2004 through 2009 at a fixed energy price of \$58.60 per megawatt-hour. In addition, Calpine provides up to 2.7 million and 4.8 million megawatt hours of additional, flexible energy in 2002 and 2003, respectively; with energy pricing indexed to gas and a two-year fixed capacity payment.

(2) *Contract 2* provides for baseload power deliveries of 200 megawatts for the first half of 2002 and 1,000 megawatts from July 1, 2002 through 2009 at a fixed energy price of \$59.60 per megawatt-hour. Calpine provides up to 1.7 million and 3.0 million megawatt hours of additional, flexible energy in 2002 and 2003, respectively; with energy pricing indexed to gas and a two-year fixed capacity payment. DWR has the right to complete four Calpine projects planned for California if Calpine does not meet certain milestones with respect to each project. However, if DWR exercises this right, DWR must reimburse Calpine for all construction costs and certain other costs incurred to date in connection with the project(s) being completed by DWR and this right has no effect on the prices, terms and conditions associated with the energy products being sold to DWR under Contract 2.

(3) *Contract 3* provides DWR with a 10-year option for 2,000 hours (annually) for 495 megawatts of peak power in exchange for fixed annual capacity payments of \$90 million for years one through five and \$80 million per year thereafter. If DWR exercises its option, the energy price paid is indexed to gas.

(4) *Contract 4* provides DWR up to 225 megawatts of new peaking capacity for a 3-year term, beginning with commercial operation of the Los Esteros Energy Center, for fixed annual average capacity payments and an energy price indexed to gas.

*California Electric Power Fund.* In November 2002, the DWR completed the issuance of \$11.3 billion in revenue bonds. Part of the proceeds from this bond issuance was used to fund the Electric Power Fund (the “Fund”), which will be used to meet DWR’s payment obligations under its long-term energy contracts. Revenue requirements for the repayment of the bonds will be determined at least annually and submitted to the CPUC. Under the terms of a Rate Agreement between the DWR and the CPUC, the CPUC is required to set rates for the customers of the State’s investor owned utilities (“IOUs”), such that the Fund will always

have monies to retire the bonds when due. DWR is shifting certain power procurement responsibilities to the IOUs, other than those procurement obligations already committed under the terms of its long-term contracts, such as the four long-term contracts with CES discussed above. Ultimately, the financial responsibility for the long-term contracts may be transferred to the IOUs; such as, PG&E; however, this will not occur until a number of issues are addressed, including IOU creditworthiness.

*California Refund Proceeding.* On August 2, 2000 the California Refund Proceeding was initiated by a complaint made at FERC by San Diego Gas & Electric Company and under Section 206 of the Federal Power Act, alleging, among other things, that the markets operated by the California Independent System Operator (“CAISO”) and the California Power Exchange (“PX”) PX were dysfunctional. In addition to commencing an inquiry regarding the market structure, FERC established a refund effective period of October 2, 2000 to June 19, 2001 for sales made into those markets. On June 19, 2001, FERC ordered price mitigation throughout the western United States in an attempt to reduce the dependence of the California market on spot markets in favor of longer-term committed energy supplies. Subsequently, the Chief Administrative Law Judge (“Chief ALJ”) issued his report and recommendations to FERC on July 12, 2001 on how refunds should be calculated. Based on the Chief ALJ’s report, FERC established a subsequent proceeding to determine the refund liability for each seller for a refund period of October 2, 2000 through June 19, 2001. During this refund period we sold much of our California merchant capacity in the bilateral markets, which sales are not subject to refund under this proceeding. As a result of an order by the U.S. Court of Appeals for the Ninth Circuit, FERC is required to consider the impact on possible market manipulation on potential refund liability. In November 2002, FERC issued an order establishing a special hundred-day period for additional discovery. In March 2003 the parties were required to submit reports addressing any such market manipulation. This aspect of the proceeding has not yet been concluded.

On December 12, 2002, the Administrative Law Judge issued a Certification of Proposed Finding on California Refund Liability making an initial determination of refund liability (the “December 12 Certification”). Under the December 12 Certification, Calpine had potential direct and indirect refund liability of approximately \$6.2 million, considering the offsets available to us. We have fully reserved the amount of refund liability that would potentially be owed under the December 12 Certification.

On March 26, 2003, FERC issued an order adopting many of the ALJ’s findings set forth in the December 12 Certification (the “March 26 Order”). In addition, as a result of certain findings by the FERC staff concerning the unreliability or mis-reporting of certain reported indices for gas prices in California during the refund period, FERC ordered that the basis for calculating a party’s potential refund liability be modified by substituting a gas proxy price based upon gas prices in the producing areas plus the tariff transportation rate for the California gas price indices previously adopted in the refund proceeding. At this time, we are unable to determine our potential liability under the March 26 Order. However, based upon a preliminary understanding, we believe that such liability is likely to increase from that calculated in accordance with the December 12 Certification, but we are unable to estimate the amount of such potential increase at this time.

The final outcome of this proceeding and the impact on our business is uncertain at this time.

*FERC Investigation into Western Markets.* On February 13, 2002, FERC initiated an investigation of potential manipulation of electric and natural gas prices in the western United States. This investigation was initiated as a result of allegations that Enron and others, used their market position to distort electric and natural gas markets in the West. The scope of the investigation is to consider whether, as a result of any manipulation in the short-term markets for electric energy or natural gas or other undue influence on the wholesale markets by any party since January 1, 2000, the rates of the long-term contracts subsequently entered into in the West are potentially unjust and unreasonable. FERC has stated that it may use the information gathered in connection with the investigation to determine how to proceed on any existing or future complaint brought under Section 206 of the Federal Power Act involving long-term power contracts entered into in the West since January 1, 2000, or to initiate a Federal Power Act Section 206 or Natural Gas Act Section 5 proceeding on its own initiative. On August 13, 2002, the FERC staff issued the Initial Report on Company-Specific Separate Proceedings and Generic Reevaluations; Published Natural Gas Price Data; and Enron Trading Strategies (the “Initial Report”) summarizing its initial findings in this investigation.

There were no findings or allegations of wrongdoing by Calpine set forth or described in the Initial Report. On March 26, 2003, the FERC staff issued a final report in this investigation (the “Final Report”). The FERC staff recommended that FERC issue a show cause order to a number of companies, including Calpine, regarding certain power scheduling practices that may potentially be in violation of the CAISO’s or CalPX’ tariff. We believe that it did not violate these tariffs and that, to the extent that such a finding could be made, any potential liability would not be material. The Final Report also recommended that FERC modify the basis for determining potential liability in the California Refund Proceeding discussed above.

*CPUC Proceeding Regarding QF Contract Pricing for Past Periods.* Our Qualifying Facilities (“QF”) contracts with Pacific Gas and Electric Company (“PG&E”) provide that the CPUC has the authority to determine the appropriate utility “avoided cost” to be used to set energy payments for certain QF contracts by determining the short run avoided cost (“SRAC”) energy price formula. In mid 2000, our QF facilities elected the option set forth in Section 390 of the California Public Utility Code, which provides QFs the right to elect to receive energy payments based on the California Power Exchange (“PX”) market clearing price instead of the price determined by SRAC. Having elected such option, we 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. 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 at one point issued a proposed decision to the effect that the PX Price was the appropriate price for energy payments under the California Public Utility Code but tabled it, and 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.

### ***Government Regulation***

*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 and oil and gas exploration and production 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 repeal PUHCA and amend PURPA by limiting its mandatory purchase obligation to existing contracts. In light of the circumstances in California, the Pacific Gas and Electric Company bankruptcy and the Enron Corp. bankruptcy, among other events in recent years, there are a number of federal legislative and regulatory initiatives that could result in changes in how the energy markets are regulated. We do not know whether this legislation or regulatory initiatives will be adopted or, if adopted, what form they may take. We cannot provide assurance that any legislation or regulation ultimately adopted 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. However, in light of the circumstances in the California power markets and the bankruptcies of both PG&E and Enron, the pace and direction of further deregulation at the state level in many jurisdictions is uncertain. See Item 1. “Business — Recent Developments — California Power Market.”

### ***Other Risk Factors***

*We depend on our management and employees.* Our success is largely dependent on the skills, experience and efforts of our people. While we believe that we have excellent depth throughout all levels of management and in all key skill levels of our employees, the loss of the services of one or more members of our senior management or numerous employees with critical skills, 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:

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

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.

*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:

- general conditions in our industry, the power markets in which we participate, or the worldwide economy;
- announcements of developments related to our business or sector;
- fluctuations in our results of operations;
- our debt to equity ratios and other leverage ratios;
- effect of significant events relating to the energy sector in general;
- sales of substantial amounts of our securities into the marketplace;
- 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.

## EMPLOYEES

As of December 31, 2002, we employed 3,353 people, of whom 48 (domestic and international) 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. Although we are an asset-based company, we are successful because of the talents, intelligence, resourcefulness and energy level of our employees. As discussed in our strategy section, our employee knowledge base enables us to optimize the value and profitability of our electricity production and prudently manage the risks inherent in our business.

## SUMMARY OF KEY ACTIVITIES

### *Finance*

#### New Funding and Repayments:

<u>Date</u>	<u>Amount</u>	<u>Description</u>
1/31/02	Up to \$232.0 million	Siemens Westinghouse Power Corporation equipment financing
3/13/02	\$64.8 million	Michael Petroleum Note Payable repayment
4/1/02	\$10.0 million	Silverado Note Payable repayment
5/10/02	\$500.0 million	Funding under two-year term loan
5/24/02	\$100.0 million	Funding for Gilroy and King City Peaking Projects
5/31/02	\$500.0 million	Funding under two-year term loan
8/7/02	\$50.0 million	Repayment of peaker funding
8/22/02	\$106.0 million	Project financing for the construction of the Blue Spruce Energy Center
8/29/02	US\$147.5 million, Cdn\$230 million	Closing of Canadian Power Income Fund offering
8/29/02	US\$80.1 million, Cdn\$125.0 million	Completed the sale of certain non-strategic oil and gas properties ("Medicine River properties") located in central Alberta to NAL Oil and Gas Trust and another institutional investor
9/20/02	US\$21.9 million Cdn\$34.5 million	Closing of Canadian Power Income Fund exercise of over-allotment option
10/1/02	US\$244.3 million Cdn\$387.5 million	Sale of substantially all of our British Columbia oil and gas properties to Calgary, Alberta-based Pengrowth Corporation (which included US\$203.2 million in aggregate principal amount of the Company's debt securities)
10/9/02	\$50.4 million	Repayment under \$1.0 billion term loan
12/20/02	\$87.0 million	Project financing for the Newark and Parlin Power Plants
1/2/02-4/30/02	\$878.0 million	Repurchases of Zero-Coupon Convertible Debentures Due 2021

Sale of 4% Convertible Senior Notes Due 2006 and Common Stock:

<u>Date</u>	<u>Offering</u>	<u>Description</u>	<u>Use of Proceeds</u>
1/3/02	\$100 million	Conversion price of \$18.07 per common share	For general corporate purposes
4/30/02	\$759 million, gross	66 million shares at \$11.50 per share	For general corporate purposes

Working Capital Credit Facility:

<u>Date</u>	<u>Amount</u>	<u>Security</u>	<u>Use of Proceeds</u>
3/12/02	\$2.0 billion	Natural gas properties, Saltend Power Plant, our equity investment in 9 U.S. power plants, 65% of the capital stock of Calpine Canada Ltd., and our remaining first tier domestic subsidiaries (excluding CES)	Finance capital expenditures and other general corporate purposes

Other:

<u>Date</u>	<u>Description</u>
1/02	Letter of intent for sale/leaseback of 11 California peaker facilities
3/12/02	Fitch, Inc. lowered the credit rating on senior unsecured debt from BB+ to BB, and it lowered the rating on convertible trust preferred securities from BB- to B
3/25/02	Standard & Poor's downgraded corporate credit rating from BB+ to BB, and senior unsecured debt from BB+ to B+
3/29/02	Sale of 11.4% interest in Lockport Power Plant for \$27.3 million
4/2/02	Proposed sale of DePere Energy Center for \$120 million, including termination of existing power purchase agreement
4/22/02	Renegotiation of California Department of Water Resources long-term power contracts
6/28/02	Execution of definitive agreements with Wisconsin Public Service for the sale of DePere Energy Center, including termination of existing power purchase agreement
9/16/02	Received regulatory approval for the sale of the DePere Energy Center
9/30/02	Renegotiation of a 10-year power sales agreement with the City of Lodi
10/25/02	Received approximately \$22.2 million from Las Vegas-based Nevada Power Company in payment of outstanding payables owed for power deliveries from May through September 2002
10/31/02	Received approximately \$3 million from Goldking Energy Corporation for all of the oil and gas properties in Drake Bay Field
11/25/02	Entered into a five-year power sales agreement with the Florida Municipal Power Agency for up to 100-megawatts
12/18/02	Completed the sale of the DePere Energy Center for \$120.4 million

### ***Power Plant Development and Construction***

<u>Date</u>	<u>Project</u>	<u>Description</u>
1/02	Gilroy Peaking Energy Center	Commercial operation
2/02	Magic Valley Generating Station	Commercial operation
2/02	King City Energy Center (Peaker Unit)	Commercial operation
3/02	Aries Power Project	Partial commercial operation
4/02	Island Cogeneration Plant	Commercial operation
4/02	Channel Energy Center	Combined-cycle operation
5/02	Aries Power Peaker Plant	Combined-cycle operation
5/02	Baytown Energy Center	Commercial operation
6/02	Metcalf Energy Center	Construction commenced
6/02	Decatur Energy Center	Partial commercial operation
6/02	Freestone Energy Center	Partial commercial operation
6/02	Zion Energy Center	Commercial operation
6/02	Delta Energy Center	Commercial operation
7/02	Freestone Energy Center	Combined-cycle operation
7/02	Bethpage Energy Peaker Center	Commercial operation
7/02	Oneta Energy Center	Partial commercial operation
8/02	Yuba City Energy Center	Commercial operation
8/02	Acadia Energy Center	Commercial operation
8/02	Hermiston Energy Center	Commercial operation
8/02	Auburndale Peaking Energy Center	Commercial operation
10/02	Corpus Christi Energy Center	Commercial operation
10/02	Ontelaunee Energy Center	Commercial operation
10/02	Corpus Christi Energy Center	Commercial operation
12/02	Feather River Energy Center	Commercial operation

### ***Turbine Cancellations***

<u>Date of Announcement</u>	<u>Reduction in Capital Spending</u>	<u>Earnings Effect</u>
3/12/02	\$1.2 billion in 2002 \$1.8 billion in 2003	\$168.5 million pre-tax charge in 2002

### ***Annual Meeting of Stockholders on May 23, 2002***

#### **Stockholders' Voting Results**

- Election of Peter Cartwright and Susan C. Schwab as Class III Directors for a three-year term expiring 2005
- Amendment to the Company's 1996 Stock Incentive Plan to increase by 12 million the number of shares of the Company's Common Stock available for grants of options and other stock-based awards under such plan
- Amendment to the Company's Employee Stock Purchase Plan to increase by 8 million the number of shares of the Company's Common Stock available for grants of purchase rights under such plan
- Proposal regarding composition of the Company's Board of Directors — not approved

- Proposal that the Board of Directors be requested to redeem the stockholders right plan unless such plan is approved by a majority vote of the stockholders to be held as soon as may be practicable — approved
- Ratification of the appointment of Deloitte & Touche LLP as independent accountants for the fiscal year ending December 31, 2002

The three-year terms of Class I and Class II Directors continued after the Annual Meeting and will expire in 2003 and 2004, respectively. The Class I Directors are Jeffrey E. Garten, George J. Stathakis, and John O. Wilson. The Class II Directors are Ann B. Curtis, Kenneth T. Derr and Gerald Greenwald.

See Item 1. “Business — Recent Developments” for 2003 developments.

## **Item 2. *Properties***

Our principal executive office located in San Jose, California is held under leases that expire through 2008, and we also lease offices, with leases expiring through 2013, in Dublin, Folsom and Walnut Creek, California; Houston, Texas; Boston, Massachusetts; Calgary, Alberta, and Jupiter, Florida. We hold additional leases for other satellite offices.

We either lease or own the land upon which our power-generating facilities are built. We believe that our properties are adequate for our current operations. A description of our power-generating facilities is included under Item 1. “Business”.

We have leasehold interests in 107 leases comprising 21,888 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 41 leases comprising approximately 46,519 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., and Gilbert Laustsen Jung Associates Ltd., as of December 31, 2002, utilizing year end product prices and costs

held constant, our proved oil, natural gas, and natural gas liquids (“NGLs”) reserve volumes, in millions of barrels (“MMBbls”) and billions of cubic feet (“Bcf”) are as follows:

	<u>As of December 31, 2002</u>	
	<u>Oil and NGLs</u> <u>(MMBbls)</u>	<u>Gas (Bcf)</u>
<b>United States</b>		
Proved developed .....	2.5	378
Proved undeveloped .....	<u>1.6</u>	<u>197</u>
Total .....	<u>4.1</u>	<u>575</u>
<b>Canada</b>		
Proved developed .....	11.6	262
Proved undeveloped .....	<u>1.3</u>	<u>39</u>
Total .....	<u>12.9</u>	<u>301</u>
<b>Consolidated</b>		
Proved developed .....	14.1	640
Proved undeveloped .....	<u>2.9</u>	<u>236</u>
Total .....	<u>17.0</u> (1)	<u>876</u>

(1) 17 MMBbls of oil is equivalent to 102 Bcf of gas using a conversion factor of six cubic feet of gas to one barrel of crude oil and natural gas liquids. On an equivalent basis, proved reserves at year-end totaled 978 Bcfe.

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, 2002, totaled approximately \$221 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, 2002. 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. Productive wells are wells in which we have a working interest and are capable of producing oil or natural gas.

	<u>Undeveloped Acres</u>		<u>Developed Acres</u>		<u>Productive Wells</u>	
	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>	<u>Gross</u>	<u>Net</u>
<b>United States</b>						
Arkansas .....	160	80	3,521	1,399	32	14
California .....	22,731	16,630	39,964	34,769	253	208
Colorado .....	9,618	7,423	8,242	5,958	65	64
Kansas .....	118,488	107,933	—	—	—	—
Louisiana.....	3,006	568	10,597	2,315	26	6
Mississippi.....	5,473	1,040	11,337	2,919	14	4
Missouri .....	35,008	31,651	43	43	—	—
Montana .....	35,606	24,495	960	240	2	1
New Mexico .....	2	2	9,568	8,903	50	43
Offshore.....	2,500	2,500	20,760	14,891	31	21
Oklahoma .....	492	92	21,589	6,614	86	20
Texas .....	49,392	28,345	99,426	48,793	552	263
Wyoming.....	<u>46,651</u>	<u>34,941</u>	<u>600</u>	<u>17</u>	<u>—</u>	<u>—</u>
Total United States .....	329,127	255,700	226,607	126,861	1,111	644
<b>Canada</b>						
Alberta .....	955,655	660,695	819,827	359,935	2,587	753
British Columbia .....	275,950	58,506	15,774	4,080	—	—
Saskatchewan .....	<u>879</u>	<u>374</u>	<u>394</u>	<u>70</u>	<u>—</u>	<u>—</u>
Total Canada .....	<u>1,232,484</u>	<u>719,575</u>	<u>835,995</u>	<u>364,085</u>	<u>2,587</u>	<u>753</u>
<b>Consolidated Total</b> .....	<u><u>1,561,611</u></u>	<u><u>975,275</u></u>	<u><u>1,062,602</u></u>	<u><u>490,946</u></u>	<u><u>3,698</u></u>	<u><u>1,397</u></u>

The following table sets forth the number of gross exploratory and gross development wells drilled in which we participated during the last three fiscal years. The number of wells drilled refers to the number of wells commenced at any time during the respective fiscal year. Productive wells are either producing wells or wells capable of commercial production. At December 31, 2002, we were in the process of drilling three wells (net 3) in the US and two wells (net 1.5) in Canada.

	Exploratory			Development		
	Productive	Dry	Total	Productive	Dry	Total
<b>2002</b>						
United States .....	—	6	6	41	4	45
Canada .....	<u>1</u>	<u>1</u>	<u>2</u>	<u>87</u>	<u>8</u>	<u>95</u>
Total .....	<u>1</u>	<u>7</u>	<u>8</u>	<u>128</u>	<u>12</u>	<u>140</u>
<b>2001</b>						
United States .....	5	2	7	66	12	78
Canada .....	<u>2</u>	<u>—</u>	<u>2</u>	<u>186</u>	<u>26</u>	<u>212</u>
Total .....	<u>7</u>	<u>2</u>	<u>9</u>	<u>252</u>	<u>38</u>	<u>290</u>
<b>2000</b>						
United States .....	7	4	11	28	3	31
Canada .....	<u>7</u>	<u>2</u>	<u>9</u>	<u>154</u>	<u>46</u>	<u>200</u>
Total .....	<u>14</u>	<u>6</u>	<u>20</u>	<u>182</u>	<u>49</u>	<u>231</u>

The following table sets forth, for each of the last three fiscal years, the number of net exploratory and net development wells, drilled by us based on our proportionate working interest in such wells:

	Exploratory			Development		
	Productive	Dry	Total	Productive	Dry	Total
<b>2002</b>						
United States .....	—	3.9	3.9	36.4	2.8	39.2
Canada .....	<u>.5</u>	<u>.5</u>	<u>1.0</u>	<u>38.9</u>	<u>4.2</u>	<u>43.1</u>
Total .....	<u>.5</u>	<u>4.4</u>	<u>4.9</u>	<u>75.3</u>	<u>7.0</u>	<u>82.3</u>
<b>2001</b>						
United States .....	2.2	1.0	3.2	58.9	7.4	66.3
Canada .....	<u>1.6</u>	<u>—</u>	<u>1.6</u>	<u>97.2</u>	<u>19.7</u>	<u>116.9</u>
Total .....	<u>3.8</u>	<u>1.0</u>	<u>4.8</u>	<u>156.1</u>	<u>27.1</u>	<u>183.2</u>
<b>2000</b>						
United States .....	3.2	1.0	4.2	15.5	1.4	16.9
Canada .....	<u>2.8</u>	<u>1.3</u>	<u>4.1</u>	<u>93.3</u>	<u>36.0</u>	<u>129.3</u>
Total .....	<u>6.0</u>	<u>2.3</u>	<u>8.3</u>	<u>108.8</u>	<u>37.4</u>	<u>146.2</u>

The following table shows our annual average wellhead sales prices and average production costs (excluding production taxes). The average sales prices include realized gains and losses for derivative contracts we enter to manage price risk related to our sales volumes.

	<u>2002</u>	<u>2001</u>	<u>2000</u>
<b>UNITED STATES</b>			
Sales price			
Natural gas (per Mcf) .....	\$ 3.12	\$ 4.81	\$ 4.11
Oil and condensate (per barrel) .....	\$21.58	\$23.30	\$24.71
Natural gas liquids (per barrel) .....	\$13.35	\$15.67	\$15.77
Production cost (per Mcfe) .....	\$ 0.50	\$ 0.53	\$ 0.48
<b>CANADA</b>			
Sales price			
Natural gas (per Mcf) .....	\$ 2.44	\$ 3.25	\$ 3.18
Oil and condensate (per barrel) .....	\$22.29	\$20.16	\$27.03
Natural gas liquids (per barrel) .....	\$18.48	\$20.96	\$24.67
Production cost (per Mcfe) .....	\$ 0.60	\$ 0.53	\$ 0.43
<b>TOTAL</b>			
Sales price			
Natural gas (per Mcf) .....	\$ 2.75	\$ 3.78	\$ 3.45
Oil and condensate (per barrel) .....	\$22.20	\$20.38	\$26.92
Natural gas liquids (per barrel) .....	\$18.35	\$20.90	\$24.56
Production cost (per Mcfe) .....	\$ 0.56	\$ 0.53	\$ 0.44

### Item 3. *Legal Proceedings*

We are party to various litigation matters arising out of the normal course of business, the more significant of which are summarized below. The ultimate outcome of each of these matters cannot presently be determined, nor can the liability that could potentially result from a negative outcome in each case presently be reasonably estimated. The liability we may ultimately incur with respect to any one of these matters in the event of a negative outcome may be in excess of amounts currently accrued with respect to such matters and as a result of these matters may potentially be material to our consolidated financial statements.

*Securities Class Action Lawsuits.* Fourteen shareholder lawsuits have been filed against Calpine and certain of its officers in the United States District Court, Northern District of California. The actions captioned *Weisz v. Calpine Corp.*, et al., filed March 11, 2002, and *Labyrinth Technologies, Inc. v. Calpine Corp.*, et al., filed March 28, 2002, are purported class actions on behalf of purchasers of Calpine stock between March 15, 2001 and December 13, 2001. *Gustaferra v. Calpine Corp.*, filed April 18, 2002, is purported class action on behalf of purchasers of Calpine stock between February 6, 2001 and December 13, 2001. The eleven other actions were filed between March 18, 2002 and April 23, 2002. The complaints in these eleven actions are virtually identical — three law firms, in conjunction with other law firms as co-counsel, filed them. All eleven lawsuits are purported class actions on behalf of purchasers of our securities between January 5, 2001 and December 13, 2001.

The complaints in these fourteen actions allege that, during the purported class periods, certain senior Calpine Executives issued false and misleading statements about our financial condition in violation of Sections 10(b) and 20(1) of the Securities Exchange Act of 1934, as well as Rule 10b-5. These actions seek an unspecified amount of damages, in addition to other forms of relief.

In addition, a fifteenth securities class action, *Ser v. Calpine, et al.*, was filed on May 13, 2002. The underlying allegations in the Ser action are substantially the same as those in the above-referenced actions. However, the Ser action is brought on behalf of a purported class of purchasers of our 8.5% Senior Notes due

February 15, 2011 (“2011 Notes”) and the alleged class period is October 15, 2001 through December 13, 2001. The Ser Complaint alleges that in violation of Sections 11 and 15 of the Securities Act of 1933, the Prospectus Supplement dated October 11, 2001, for the 2011 Notes contained false and misleading statements regarding our financial condition. This action names as defendants Calpine, certain of its officers and directors, and the underwriters of the 2011 Note offering as defendants, and seeks an unspecified amount of damages, in addition to other forms of relief.

All fifteen of these securities class action lawsuits were consolidated in the U.S. District Court Northern District Court of California. In January 2003, Plaintiffs filed an amended consolidated complaint naming additional officers as defendants and adding new security law claims. We consider these lawsuits to be without merit and intend to defend vigorously against them.

A sixteenth securities class action, *Hawaii Structural Ironworkers Pension Fund v. Calpine, et al.*, was filed on March 11, 2003 against Calpine, its directors and certain investment banks in the California Superior Court, San Diego County. The underlying allegations in the Hawaii Structural Ironworkers Pension Fund action (“Hawaii action”) are substantially the same as those in the above-referenced actions. However, the Hawaii action is brought on behalf of a purported class of purchasers of our equity securities sold to public investors in the our April 2002 equity offering. The Hawaii action alleges that the Registration Statement and Prospectus filed by Calpine which became effective on April 24, 2002 contained false and misleading statements regarding our financial condition in violation of Sections 11, 12 and 15 of the Securities Act of 1933. The Hawaii action relies in part on our restatement of certain past financial results, announced on March 3, 2003, to support its allegations. The Hawaii action seeks an unspecified amount of damages, in addition to other forms of relief. We consider this lawsuit to be without merit and intend to defend vigorously against it.

*Johnson v. Peter Cartwright, et al.* On December 17, 2001, a shareholder filed a derivative lawsuit on behalf of the Company against its directors and one of its senior officers. This lawsuit is styled *Johnson v. Cartwright, et al.* and is pending in the California Superior Court, Santa Clara County. We are a nominal defendant in this lawsuit, which alleges claims relating to purportedly misleading statements about Calpine and stock sales by certain of the director defendants and the officer defendant. In December 2002, the court dismissed the complaint with respect to certain of the director defendants for lack of personal jurisdiction, though the plaintiff may appeal this ruling. In early February 2003, the plaintiff filed an amended complaint. We consider this lawsuit to be without merit and intend to vigorously defend against it.

*Gordon v. Peter Cartwright, et al.* On August 8, 2002, a shareholder filed a derivative lawsuit in the United States District Court for the Northern District of California on behalf of Calpine against its directors, captioned *Gordon v. Cartwright, et al.*, similar to *Johnson v. Cartwright*. Motions have been filed to dismiss the action against certain of the director defendants on the grounds of lack of personal jurisdiction, as well as to dismiss the complaint in total on other grounds. In February 2003, the plaintiff agreed to stay these proceedings in favor of the consolidated federal securities class action described above and to dismiss without prejudice certain director defendants. We consider this lawsuit to be without merit and intend to vigorously defend against it.

*California Business & Professions Code Section 17200 Cases. The lead case T&E Pastorino Nursery v. Duke Energy Trading and Marketing, L.L.C., et al.* This purported class action complaint filed in May 2002 against twenty energy traders and energy companies including CES alleges that defendants exercised market power and manipulated prices in violation of California Business & Professions Code Section 17200 et seq., and seeks injunctive relief, restitution and attorneys’ fees. We also have been named in seven other similar complaints for violations of Section 17200. All seven cases have been removed from the various state courts in which they were originally filed to federal court for pretrial proceedings with other cases in which we are not named as a defendant. In addition, plaintiffs in the case have filed a motion to remand that matter to California state court.

We consider the allegations against Calpine and its subsidiaries in each of these lawsuits to be without merit, and intend to vigorously defend against them.

*McClintock et al. v. Vikram Budhraj, et al. California Department of Water Resources Case.* On May 1, 2002, California State Senator Tom McClintock and others filed a complaint against Vikram Budhraj, a consultant to the California Department of Water Resources (“DWR”), DWR itself, and more than twenty nine energy providers and other interested parties, including Calpine. The complaint alleges that the long term power contracts that DWR entered into with these energy providers, including Calpine, are rendered void because Budhraj, who negotiated the contracts on behalf of the DWR, allegedly had an undisclosed financial interest in the contracts due to his connection to one of the energy providers, Edison International. Among other things, the complaint seeks an injunction prohibiting further performance of the long-term contracts and restitution of any funds paid to energy providers by the State of California under the contracts. The action has been stayed by order of the Court since August 26, 2002, pending resolution of an earlier-filed state court action involving the same parties and subject matter captioned *Carboneau v. State of California* in which we are not a defendant. We consider the allegations against the Company in this lawsuit to be without merit and intend to vigorously defend against them.

*Nevada Power Company and Sierra Pacific Power Company v. Calpine Energy Services, L.P. before the FERC, filed on December 4, 2001. Nevada Section 206 Complaint.* On December 4, 2001, Nevada Power Company (“NPC”) and Sierra Pacific Power Company (“SPPC”) filed a complaint with FERC under Section 206 of the Federal Power Act against a number of parties to their power sales agreements, including the Company. NPC and SPPC allege in their complaint, which seeks a refund, that the prices they agreed to pay in certain of the power sales agreements, including those signed with Calpine, were negotiated during a time when the power market was dysfunctional and that they are unjust and unreasonable. We consider the complaint to be without merit and are vigorously defending against it. The Administrative Law Judge issued an Initial Decision on December 19, 2002 that found for Calpine and the other respondents in the case and denied NPC the relief that it was seeking. The parties are waiting for a final FERC order in this proceeding.

*Calpine Corporation v. Automated Credit Exchange.* On March 5, 2002, we sued Automated Credit Exchange (“ACE”) in the Superior Court of the State of California for the County of Alameda for negligence and breach of contract to recover reclaim trading credits, a form of emission reduction credits that we should have been held in our account with U.S. Trust Company (“US Trust”). Calpine wrote-off \$17.7 million in December 2001 related to losses that it alleged were caused by ACE. Calpine and ACE entered into a settlement agreement on March 29, 2002, pursuant to which ACE made a payment to us of \$7 million and transferred to us the rights to the emission reduction credits to be held by ACE. We recognized the \$7 million in the second quarter of 2002. In June 2002 a complaint was filed by InterGen North America, L.P. (“InterGen”) against Anne M. Sholtz, the owner of ACE, and EonXchange, another Sholtz-controlled entity, which filed for bankruptcy protection on May 6, 2002. InterGen alleges it suffered a loss of emission reduction credits from EonXchange in a manner similar to our loss from ACE. InterGen’s complaint alleges that Anne Sholtz co-mingled assets among ACE, EonXchange and other Sholtz entities and that ACE and other Sholtz entities should be deemed to be one economic enterprise and all retroactively included in the EonXchange bankruptcy filing as of May 6, 2002. InterGen’s complaint refers to the payment by ACE of \$7 million to us alleging that InterGen’s ability to recover from EonXchange has been undermined thereby. We are unable to assess the likelihood of InterGen’s complaint being upheld at this time.

*Geysers Reliability Must Run Section 206 Proceeding.* California Independent System Operator, California Electricity Oversight Board, Public Utilities Commission of the State of California, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison (collectively referred to as the “Buyers Coalition”), filed a complaint on November 2, 2001 at the Federal Energy Regulatory Commission requesting the commencement of a Federal Power Act Section 206 proceeding to challenge one component of a number of separate settlements previously reached on the terms and conditions of “reliability must-run” contracts (“RMR Contracts”) with certain generation owners, including Geysers Power Company, LLC, which settlements were also previously approved by the FERC. RMR contracts require the owner of the specific generation unit to provide energy and ancillary services when called upon to do so by the ISO to meet local transmission reliability needs or to manage transmission constraints. The Buyers Coalition has asked FERC to find that the availability payments under these RMR Contracts are not just and reasonable. Geysers Power Company, LLC filed an answer to the complaint in November 2001. To date, FERC has not

established a section 206 proceeding. The outcome of this litigation and the impact on the Company's business cannot be presently determined.

*International Paper Company v. Androscoggin Energy LLC.* In October 2000, International Paper Company filed a complaint against Androscoggin Energy LLC ("AELLC") alleging that AELLC breached certain contractual representations and warranties by failing to disclose facts surrounding the termination, effective May 8, 1998, of one of AELLC's fixed-cost gas supply agreements. We had acquired a 32.3% interest in AELLC as part of the Skygen transaction which closed in October 2000. AELLC filed a counterclaim against International Paper Company that has been referred to arbitration. AELLC may commence the arbitration counterclaim after discovery has progressed further, depending on the outcome of the discussions referred to below. On November 7, 2002, the court issued an opinion on the parties' cross motions for summary judgment finding in AELLC's favor on certain matters though granting summary judgment to International Paper Company on the liability aspect of a particular claim against AELLC. While the matter is expected to proceed to the damages aspect of trial in mid-2003, we are seeking to engage IP in discussions to explore a commercial resolution to the matter. We cannot currently estimate the possible loss, if any, it may ultimately incur as a result of this matter.

In addition, we are involved in various other legal actions proceedings, and state and regulatory investigations relating to our business. These actions and proceedings are described in detail elsewhere in this report. See Item 1. "Business — Risk Factors — California Power Market." We are involved in various other claims and legal actions arising out of the normal course of its business. We do not expect that the outcome of these proceedings will have a material adverse effect on our financial position or results of operations.

**Item 4. Submission of Matters to a Vote of Security Holders**

None.

**PART II**

**Item 5. Market for Registrant's Common Equity and Related Stockholder Matters**

Our common stock is traded on the New York Stock Exchange under the symbol "CPN." Public trading of the common stock commenced on September 20, 1996. Prior to that, there was no public market for the common stock. The following table sets forth, for the periods indicated, the high and low sale price per share of the common stock on The New York Stock Exchange.

	<u>High</u>	<u>Low</u>
<b>2002</b>		
First Quarter . . . . .	\$17.28	\$ 6.15
Second Quarter . . . . .	13.55	5.30
Third Quarter . . . . .	7.29	2.36
Fourth Quarter . . . . .	4.69	1.55
<b>2001</b>		
First Quarter . . . . .	\$58.04	\$29.00
Second Quarter . . . . .	57.35	36.20
Third Quarter . . . . .	46.00	18.90
Fourth Quarter . . . . .	28.85	10.00

As of March 26, 2003, there were approximately 1,984 holders of record of our common stock. On March 26, 2003, the last sale price reported on the New York Stock Exchange for our common stock was \$3.21 per share.

We have not declared any cash dividends on the common stock during the past two fiscal years. We do not anticipate paying any cash dividends on the common stock in the foreseeable future because we intend to

retain our earnings to finance the expansion of our business and for general corporate purposes. In addition, our ability to pay cash dividends is restricted under certain of our indentures and our other debt agreements. Future cash dividends, if any, will be at the discretion of our board of directors and will depend upon, among other things, our future operations and earnings, capital requirements, general financial condition, contractual restrictions and such other factors as the board of directors may deem relevant.

*Equity Compensation Plan Information*

The following table provides certain information, as of December 31, 2002, concerning certain compensation plans under which our equity securities are authorized for issuance.

<u>Plan Category</u>	<u>Number of Securities to be Issued Upon Exercise of Outstanding Options, Warrants, and Rights</u>	<u>Weighted Average Exercise Price of Outstanding Options, Warrants and Rights</u>	<u>Number of Securities Remaining Available for Future Issuance Under Equity Compensation Plans (Excluding Securities Reflected in Column (a))</u>
<b>Equity compensation plans approved by the security holders</b>			
Calpine Corporation 1992 Stock Incentive Plan <sup>(1)</sup> . . . . .	5,192,918	\$ 0.7880	—
Calpine Corporation 1996 Stock Incentive Plan . . . . .	24,712,390	\$10.9020	10,162,039
Calpine Corporation 2000 Employee Stock Purchase Plan . . . . .			10,653,296
<b>Equity compensation plans not approved by security holders . . . . .</b>	<b>—</b>	<b>—</b>	<b>—</b>
<b>Total . . . . .</b>	<b>29,905,308</b>	<b>\$ 9.146</b>	<b>20,815,335</b>

<sup>(1)</sup> The Calpine Corporation 1992 Stock Incentive Plan was approved in 1992 by the Company's sole security holder at the time, Electrowatt Ltd.

In connection with the merger with Encal Energy Ltd., which closed in 2001, we assumed the Encal Energy Fifth Amended and Restated Stock Option Plan. 198,689 shares of Calpine Common Stock are subject to issuance upon exercise of options granted pursuant to this plan at a weighted average exercise price of \$32.279. There are no securities available for future issuance under this Plan.

*4% Convertible Senior Notes Due 2006.* On December 26, 2001, we completed a private placement of \$1.0 billion aggregate principal amount of 4% Convertible Senior Notes Due 2006 (the "Convertible Senior Notes"). The initial purchaser of the Convertible Senior Notes was Deutsche Bank Alex. Brown Inc. (the "initial purchaser"). The initial purchaser exercised its option to acquire an additional \$200.0 million aggregate principal amount of the Convertible Senior Notes by purchasing an additional \$100.0 million aggregate principal amount of the Convertible Senior Notes on each of December 31, 2001, and January 3, 2002. The offering price of the Convertible Senior Notes was 100% of the principal amount of the Convertible Senior Notes, less an aggregate underwriting discount of \$30.0 million. Each sale of the Convertible Senior Notes to the initial purchaser was exempt from registration in reliance on Section 4(2) and Regulation D under the Securities Act of 1933, as amended, as a transaction not involving a public offering. The Convertible Senior Notes were re-offered by the initial purchaser to qualified institutional buyers in reliance on Rule 144A under the Securities Act.

The Convertible Senior Notes are convertible into shares of our common stock at a conversion price of \$18.07 per share. The conversion price is subject to adjustment in certain circumstances. We have reserved 66,408,411 shares of our authorized common stock for issuance upon conversion of the Convertible Senior Notes. The Convertible Senior Notes are convertible at any time on or before the close of business on the day that is two business days prior to the maturity date, December 26, 2006, unless we have previously repurchased the Convertible Senior Notes. Holders of the Convertible Senior Notes have the right to require

us to repurchase their Convertible Senior Notes on December 26, 2004. We may choose to pay the repurchase price in cash or shares of common stock, or a combination thereof.

We subsequently filed with the SEC a registration statement with respect to resales of the Convertible Senior Notes, which was declared effective by the SEC on June 21, 2002.

**Item 6. Selected Financial Data**

**Selected Consolidated Financial Data(1)**

	Years Ended December 31,				
	2002	2001	2000	1999	1998
		Restated(1)	Restated(1)		
	(In thousands, except earnings per share)				
<b>Statement of Operations data:</b>					
Total revenue .....	\$ 7,457,899	\$ 6,754,228	\$ 2,375,178	\$ 890,789	\$ 604,448
Income before discontinued operations and cumulative effect of a change in accounting principle .....	\$ 49,092	\$ 586,311	\$ 332,803	\$ 89,939	\$ 26,480
Discontinued operations, net of tax .....	69,526	36,145	36,281	16,711	12,037
Cumulative effect of a change in accounting principle .....	—	1,036	—	—	—
Net income .....	<u>\$ 118,618</u>	<u>\$ 623,492</u>	<u>\$ 369,084</u>	<u>\$ 106,650</u>	<u>\$ 38,517</u>
Basic earnings per common share:					
Income before discontinued operations and cumulative effect of a change in accounting principle .....	\$ 0.14	\$ 1.93	\$ 1.18	\$ 0.40	\$ 0.15
Diluted earnings per common share:					
Income before discontinued operations and cumulative effect of a change in accounting principle .....	\$ 0.14	\$ 1.70	\$ 1.07	\$ 0.38	\$ 0.14
Discontinued operations, net of tax provision .....	0.19	0.10	0.11	0.07	0.07
Net income .....	<u>\$ 0.33</u>	<u>\$ 1.80</u>	<u>\$ 1.18</u>	<u>\$ 0.45</u>	<u>\$ 0.21</u>
<b>Balance Sheet data:</b>					
Total assets .....	\$23,226,992	\$21,937,227	\$10,610,232	\$4,400,902	\$2,032,009
Short-term debt and capital lease obligations	1,651,496	903,395	64,525	47,470	5,450
Long-term debt and capital lease obligations	12,462,309	12,490,247	5,018,044	2,214,921	1,211,377
Company-obligated mandatorily redeemable convertible preferred securities of subsidiary trusts .....	\$ 1,123,969	\$ 1,122,924	\$ 1,122,390	\$ 270,713	\$ —

(1) See Note 2 of Notes to Consolidated Financial Statements regarding the restatement of financial statements.

Reconciliation of GAAP net income to EBITDA, as adjusted(1):	Years Ended December 31,				
	2002	2001	2000	1999	1998
		Restated (2)	Restated (2)		
		(In thousands)			
GAAP net income . . . . .	\$ 118,618	\$ 623,492	\$ 369,084	\$106,650	\$ 38,517
Income from unconsolidated investments in power projects . . . . .	(16,552)	(16,225)	(28,796)	(36,593)	(25,240)
Distributions from unconsolidated investments in power projects . . . . .	14,117	5,983	29,979	43,318	27,717
Adjusted net income . . . . .	116,183	613,250	370,267	113,375	40,994
Interest expense . . . . .	413,720	198,497	81,890	96,932	86,031
1/3 of operating lease expense . . . . .	37,007	33,173	21,154	11,198	5,710
Distributions on trust preferred securities . . . . .	62,632	62,412	45,076	2,565	—
Provision (benefit) for income taxes . . . . .	(19,096)	298,665	231,451	61,523	19,592
Depreciation, depletion and amortization expense . . . . .	459,465	311,302	195,863	112,665	99,891
Interest expense, provision for income taxes and depreciation from discontinued operations . . . . .	85,083	85,745	73,971	35,093	30,274
<b>EBITDA, as adjusted(1)</b> . . . . .	<b>\$1,154,994</b>	<b>\$1,603,044</b>	<b>\$1,019,672</b>	<b>\$433,351</b>	<b>\$282,492</b>

- (1) This non-GAAP measure is presented not as a measure of operating results, but rather as a measure of our ability to service debt. It should not be construed as an alternative to either (i) income from operations or (ii) cash flows from operating activities. It 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 expense, plus depreciation, depletion and amortization, plus distributions on trust preferred securities. The interest, tax and depreciation and amortization components of discontinued operations are added back in calculating EBITDA, as adjusted. In 2002, we recorded a non-cash equipment cancellation charge of \$0.4 billion. If the calculation disclosed above added back this non-cash charge, EBITDA, as adjusted would have been \$1.6 billion.
- (2) See Note 2 of Notes to Consolidated Financial Statements regarding the restatement of financial statements.

## Selected Operating Information

	Years Ended December 31,				
	2002	2001	2000	1999	1998
		Restated(1)	Restated(1)		
	(Dollars in thousands, except production and pricing data)				
<b>Power Plants:</b>					
Electricity and steam ("E&S") revenues:					
Energy .....	\$ 2,299,450	\$ 1,722,671	\$ 1,220,684	\$ 452,909	\$ 331,983
Capacity .....	797,921	536,193	376,085	252,565	125,804
Thermal and other .....	182,920	158,617	99,297	54,851	50,110
Subtotal .....	\$ 3,280,291	\$ 2,417,481	\$ 1,696,066	\$ 760,325	\$ 507,897
E&S revenue from discontinued operations .....	16,915	17,112	7,178	—	—
Spread on sales of purchased power(2) .....	527,546	345,834	11,262	2,476	334
Adjusted E&S revenues .....	\$ 3,824,752	\$ 2,780,427	\$ 1,714,506	\$ 762,801	\$ 508,231
Megawatt hours produced .....	74,541,729	43,542,293	22,749,588	14,802,709	9,864,080
All-in electricity price per megawatt hour generated .....	\$ 51.31	\$ 63.86	\$ 75.36	\$ 51.53	\$ 51.52

(1) See Note 2 of Notes to Consolidated Financial Statements regarding the restatement of financial statements.

(2) From hedging, balancing and optimization activities related to our generating assets.

Set forth above is certain selected operating information for our power plants and, through May 1999 for our geothermal steam fields at The Geysers, for which results are consolidated in our statements of operations. 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 host steam sales and other thermal revenue, including our geothermal steam field revenues prior to our acquisition of the PG&E geothermal power plants at The Geysers on May 7, 1999.

Set forth below is a table summarizing the dollar amounts and percentages of our total revenue for the years ended December 31, 2002, 2001, and 2000, that represent purchased power and purchased gas sales and the costs we incurred to purchase the power and gas that we resold during these periods (in thousands, except percentage data):

	Year Ended December 31,		
	2002	2001	2000
		Restated(1)	Restated(1)
Total revenue .....	\$7,457,899	\$6,754,228	\$2,375,178
Sales of purchased power .....	3,145,991	3,332,412	369,911
As a percentage of total revenue .....	42.2%	49.3%	15.6%
Sale of purchased gas .....	870,466	526,517	87,119
As a percentage of total revenue .....	11.7%	7.8%	3.7%
Total cost of revenue ("COR") .....	6,440,959	5,520,733	1,627,409
Purchased power expense .....	2,618,445	2,986,578	358,649
As a percentage of total COR .....	40.7%	54.1%	22.0%
Purchased gas expense .....	821,065	492,587	107,591
As a percentage of total COR .....	12.7%	8.9%	6.6%

(1) See Note 2 of Notes to Consolidated Financial Statements regarding the restatement of financial statements.

The primary reasons for the significant levels of these sales and costs of revenue items include: (a) the growth of Calpine Energy Services ("CES") in 2001 and 2002 compared to 2000 and the corresponding increase in hedging, balancing and optimization activities; (b) particularly volatile markets for electricity and natural gas, which prompted us to frequently adjust our hedge positions by buying power and gas and reselling it; (c) the accounting requirements under Staff Accounting Bulletin ("SAB") No. 101, "Revenue Recognition in Financial Statements," and Emerging Issues Task Force ("EITF") Issue No. 99-19, "Reporting Revenue Gross as a Principal versus Net as an Asset", which require us to show most of our hedging contracts on a gross basis (as opposed to netting sales and cost of revenue); and (d) rules in effect throughout 2001 and 2002 associated with the NEPOOL market in New England, which require that all power generated in NEPOOL be sold directly to the Independent System Operator ("ISO") in that market; we then buy from the ISO to serve our customer contracts. Generally accepted accounting principles require us to account for this activity, which applies to three of our merchant generating facilities, as the aggregate of two distinct sales and one purchase. This gross basis presentation increases revenues but not gross profit. The table below details the financial extent of our transactions with NEPOOL for the period indicated. The increase in 2001 is primarily due to our entrance into the NEPOOL market, which began with our acquisition of the Dighton, Tiverton, and Rumford facilities on December 15, 2000.

	Year Ended December 31,		
	2002	2001	2000
		Restated (1)	Restated (1)
		(In thousands)	
Sales to NEPOOL from power we generated .....	\$294,634	\$285,706	\$8,511
Sales to NEPOOL from hedging and other activity .....	106,861	165,416	—
Total sales to NEPOOL .....	\$401,495	\$451,122	\$8,511
Total purchases from NEPOOL .....	\$360,113	\$413,875	\$ —

(1) See Note 2 of Notes to Consolidated Financial Statements regarding the restatement of financial statements.

(The information contained in the Selected Financial Data is derived from the audited Consolidated Financial Statements of Calpine Corporation and Subsidiaries. See the Notes to the Consolidated Financial Statements and Item 7. "Management's Discussion and Analysis of Financial Condition — Results of Operation" for additional information.)

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

Set forth below are the Results of Operations for the years ending December 31, 2002, 2001, and 2000. These amounts reflect the restatement of our financial results, which are discussed in detail in Note 2 of the Notes to Consolidated Financial Statements.

**Results of Operations**

*Year Ended December 31, 2002, Compared to Year Ended December 31, 2001* (in millions, except for unit pricing information and MW volumes)

	<u>2002</u>	<u>2001</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Total Revenue . . . . .	\$7,457.9	\$6,754.2	\$703.7	10.4%
The increase in total revenue is explained by category below.				
	<u>2002</u>	<u>2001</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Electricity and steam revenue . . . . .	\$3,280.3	\$2,417.5	\$ 862.8	35.7%
Sales of purchased power for hedging and optimization . . . . .	<u>3,146.0</u>	<u>3,332.4</u>	<u>(186.4)</u>	<u>(5.6)%</u>
Total electric generation and marketing revenue . .	<u>\$6,426.3</u>	<u>\$5,749.9</u>	<u>\$ 676.4</u>	11.8%

Electricity and steam revenue increased as we completed construction and brought into operation 11 new baseload power plants, 7 new peaker facilities and 3 project expansions in 2002. Average megawatts in operation of our consolidated plants increased by 81% to 14,488 MW while generation increased by 71%. The increase in generation lagged behind the increase in average MW in operation as our baseload capacity factor dropped to 67% in 2002 from 72% in 2001 primarily because we operated fewer hours, especially in off-peak periods, than in 2001, due to the increased occurrence of unattractive market spark spreads in certain areas. The overall increase in generation was partially offset by lower average pricing, which dropped 21% as average realized electric prices, before the effects of hedging, balancing and optimization, declined to \$44.01/MWh in 2002 from \$55.52/MWh in 2001.

Sales of purchased power for hedging and optimization decreased during 2002, due to lower power prices and industry-wide credit restrictions on risk management activities in 2002.

	<u>2002</u>	<u>2001</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Oil and gas sales . . . . .	\$121.2	\$286.5	\$(165.3)	(57.7)%
Sales of purchased gas for hedging and optimization . . .	<u>870.5</u>	<u>526.5</u>	<u>344.0</u>	65.3%
Total oil and gas production and marketing revenue	<u>\$991.7</u>	<u>\$813.0</u>	<u>\$ 178.7</u>	22.0%

Oil and gas sales are net of internal consumption, which increased by \$60.3 to \$180.4 in 2002. Internal consumption is eliminated in consolidation. Additionally oil and gas sales were reduced by reclassification of \$76.5 in 2002 and \$136.4 in 2001 to discontinued operations for assets sold. Before inter-company eliminations and reclassifications to discontinued operations, oil and gas sales decreased by \$164.9 due primarily to 31% lower average realized natural gas pricing in 2002.

Sales of purchased gas for hedging and optimization increased during 2002 as we brought into operation new generation and the related level of physical gas optimization and balancing activity increased to support the new generation.

	<u>2002</u>	<u>2001</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Realized revenue on power and gas trading, net . . . . .	\$26.1	\$ 29.1	\$ (3.0)	(10.3)%
Unrealized mark-to-market gain (loss) on trading, net . .	<u>(4.6)</u>	<u>122.6</u>	<u>(127.2)</u>	(103.8)%
Total trading revenue, net . . . . .	<u>\$21.5</u>	<u>\$151.7</u>	<u>\$(130.2)</u>	(85.8)%

Realized revenue on power and gas trading activity represents the portion of trading contracts actually settled.

In the year ended December 31, 2001, we recognized a net unrealized mark-to-market gain of \$68.5 from power contracts in a market area where we did not have generation assets and approximately \$66 of gains from various other power and gas transactions. The shift from unrealized mark-to-market revenue in 2001 to unrealized loss in 2002 reflects industry-wide credit and liquidity restrictions on risk management and trading activities, which caused us to greatly curtail trading activities so that our available capacity could be concentrated on hedging activities associated with our existing physical power and gas assets. Also, in 2002 we established liquidity reserves of approximately \$6.7 against unrealized mark-to-market revenue to take into account reduced liquidity and the resulting increase in bid/ask spreads in the energy industry.

	<u>2002</u>	<u>2001</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Other revenue . . . . .	\$18.4	\$39.6	\$(21.2)	(53.5)%

The decrease in 2002 is due primarily to one-time license fee revenue of \$10.6 recognized in 2001 by our wholly-owned subsidiary Power Systems Mfg., L.L.C. (“PSM”). In addition, we recognized \$7.7 less in revenue from WRMS Engineering, Inc. (“WRMS”), our California-based engineering and architectural subsidiary, as WRMS began to increase its work related to Calpine projects for which revenue is eliminated in consolidation.

	<u>2002</u>	<u>2001</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Cost of revenue . . . . .	\$6,441.0	\$5,520.7	\$920.3	16.7%

The increase in total cost of revenue is explained by category below.

	<u>2002</u>	<u>2001</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Plant operating expense . . . . .	\$ 510.9	\$ 325.8	\$ 185.1	56.8%
Royalty expense . . . . .	17.6	27.5	(9.9)	(36.0)%
Purchased power expense for hedging and optimization . . . . .	<u>2,618.5</u>	<u>2,986.6</u>	<u>(368.1)</u>	(12.3)%
Total electrical generation and marketing expense	<u>\$3,147.0</u>	<u>\$3,339.9</u>	<u>\$(192.9)</u>	(5.8)%

Plant operating expense increased due to 11 new baseload power plants, 7 new peaker facilities and 3 expansion projects completed during 2002, but, expressed per MWh of generation, it decreased from \$7.48/MWh to \$6.85/MWh as economies of scale are being realized due to the increase in the average size of our plants.

Royalty expense decreased due to a decrease in revenue at The Geysers geothermal plants due to lower electric prices.

The decrease in purchased power expense was caused by lower power prices and by industry-wide credit restrictions on risk management activities in 2002.

	<u>2002</u>	<u>2001</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Oil and gas production expense . . . . .	\$ 97.9	\$ 90.9	\$ 7.0	7.7%
Purchased gas expense for hedging and optimization . . .	<u>821.1</u>	<u>492.6</u>	<u>328.5</u>	66.7%
Total oil and gas production and marketing expense	<u>\$919.0</u>	<u>\$583.5</u>	<u>\$335.5</u>	57.5%

Purchased gas expense for hedging and optimization increased during 2002 as we brought into operation new generation and the related level of physical gas optimization and balancing activity increased to support the new generation.

Oil and gas production expense increased primarily due to increases in gas treating and transportation costs coupled with higher lifting costs due to a 1% increase in equivalent volumes and due to inflation.

	<u>2002</u>	<u>2001</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Fuel expense . . . . .	\$1,791.9	\$1,171.0	\$620.9	53.0%

Fuel expense increased in 2002 due to an 84% increase in gas-fired megawatt hours generated which was partially offset by significantly lower gas prices, increased usage of internally produced gas and an improved average heat rate of our generation portfolio in 2002.

	<u>2002</u>	<u>2001</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Depreciation, depletion and amortization expense . . . . .	\$459.5	\$311.3	\$148.2	47.6%

Depreciation, depletion and amortization expense increased primarily due to additional power facilities in consolidated operations during 2002 as compared to 2001.

	<u>2002</u>	<u>2001</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Operating lease expense . . . . .	\$111.0	\$99.5	\$11.5	11.6%

Operating lease expense increased due to the RockGen, Aidlin and South Point sale/leaseback transactions entered into during 2001.

	<u>2002</u>	<u>2001</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Other expense . . . . .	\$12.6	\$15.5	\$(2.9)	(18.7)%

The decrease is primarily due to \$4.1 less expense at PSM, as combustion parts sales to third parties decreased in 2002.

	<u>2002</u>	<u>2001</u> Restated	<u>\$ Change</u>	<u>% Change</u>
(Income) from unconsolidated investments in power projects . . . . .	\$(16.6)	\$(16.2)	\$(0.4)	2.5%

The modest increase is primarily due to approximately \$14.6 earned from our investment in the Acadia facility, which commenced operations in August 2002, partially offset by \$4.0 less revenue from our investment in Lockport, which we sold in the first quarter of 2002, losses at Androscoggin and Greys Ferry in 2002 due to lower spark spreads, and a \$6.7 decrease in interest income from loans to power projects resulting from the extinguishment of a note from the Delta Energy Center, LLC after we acquired the remaining 50% interest in November 2001.

	<u>2002</u>	<u>2001</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Equipment cancellation and asset impairment charge . .	\$404.7	\$ —	\$404.7	—

The pre-tax charge of \$404.7 in the year ended December 31, 2002, was a result of turbine and other equipment order cancellation charges and related write-offs as a result of our revised construction and development program. For further information, see Note 5 of the Notes to Consolidated Financial Statements.

	<u>2002</u>	<u>2001</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Project development expense .....	\$79.3	\$35.9	\$43.4	120.9%

Project development expense increased primarily because we expensed \$34.8 of previously capitalized costs due to the cancellation or indefinite suspension of certain development projects. Additionally we stopped capitalizing costs on certain development projects placed on hold.

	<u>2002</u>	<u>2001</u> Restated	<u>\$ Change</u>	<u>% Change</u>
General and administrative expense .....	\$235.7	\$153.8	\$81.9	53.3%

The increase was attributable to continued growth in personnel and associated overhead costs necessary to support the overall growth in our operations. In addition we incurred \$13.7 of severance costs and the write off of excess office space due to the reduction of our work force during 2002. General and administrative expense expressed per MWh of generation decreased to \$3.16/MWh in 2002 from \$3.53/MWh in 2001.

	<u>2002</u>	<u>2001</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Merger expense .....	\$—	\$41.6	\$(41.6)	—

The merger expense of \$41.6 in the year ended December 31, 2001, was a result of the pooling-of-interests transaction with Encal Energy Ltd. that closed on April 19, 2001.

	<u>2002</u>	<u>2001</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Interest expense .....	\$413.7	\$198.5	\$215.2	108.4%

Interest expense increased primarily due to the issuance of the 4% Convertible Senior Notes Due 2006 and additional senior notes issued in the second half of 2001 and due to the new plants entering commercial operations (at which point capitalization of interest expense ceases). Interest capitalized increased from \$498.7 for the year ended December 31, 2001, to \$575.5 for the year ended December 31, 2002, due to a larger construction portfolio during most of 2002. We expect that interest expense will continue to increase and the amount of interest capitalized will decrease in future periods as our plants in construction are completed, and, to a lesser extent, as a result of suspension of certain of our development projects and suspension of capitalization of interest thereon.

	<u>2002</u>	<u>2001</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Interest (income) .....	\$(43.1)	\$(72.5)	\$29.4	(40.6)%

The decrease in interest income is due primarily to lower cash balances and lower interest rates in 2002.

	<u>2002</u>	<u>2001</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Other (income) expense .....	\$(149.5)	\$(55.0)	\$(94.5)	171.8%

In 2002 the primary contributions to other income were the recognition of \$114.8 of gain from the receipt of Senior Notes, which were trading at a discount to fair value, as consideration for British Columbia asset sales and a \$41.5 gain on the termination of a power sales agreement. In 2001, other income resulted from contract settlements, gains from the extinguishment of debt, and gains from the sales of certain assets.

	<u>2002</u>	<u>2001</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Provision (benefit) for income taxes .....	\$(19.1)	\$298.7	\$(317.8)	(106.4)%

The decrease is primarily due to the significant decrease in income from continuing operations from 2001 to 2002. In 2002, the income tax benefit was caused by a full year of permanent tax items arising out of our cross border financings in 2001. See Note 20 of the Notes to Consolidated Financial Statements for further discussions.

	<u>2002</u>	<u>2001</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Discontinued operations, net of tax . . . . .	\$69.5	\$36.1	\$33.4	92.5%

The increase in 2002 results reflects approximately \$56.5 of gains relating to the sale of the assets, partially offset by lower earnings from these discontinued operations as they did not contribute to earnings for the full year in 2002 and due to higher gas prices in 2001. See Note 7 to the Consolidated Financial Statements for further discussion.

	<u>2002</u>	<u>2001</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Cumulative effect of a change in acct. principle, net of tax . . . . .	\$—	\$1.0	\$(1.0)	—

In 2001, the \$1.0 of additional income (net of tax of \$0.7), is due to the adoption of Financial Accounting Standards Board (“FASB”) SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities.”

	<u>2002</u>	<u>2001</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Net Income . . . . .	118.6	623.5	(504.9)	(81.0)%

The decrease in net income reflects a \$216.6 decrease in gross profit resulting primarily from lower spark spreads per MWh, which more than offset the positive effects of the increase in generation volume. It also reflects \$130.2 lower trading revenue in 2002. Additionally, we recorded \$404.7 in turbine cancellation and impairment charges in 2002, and interest expense increased by \$215.2 as more plants entered commercial operations and interest ceased being capitalized on them at that time. Finally, we experienced \$81.9 higher general and administrative expense in 2002 due to the dramatic growth in our operations. These factors were mitigated by a \$317.8 reduction in income tax expense and a \$114.8 gain from receipt of senior notes in consideration for an asset sale discussed above.

***Year Ended December 31, 2001, Compared to Year Ended December 31, 2000 (in millions, except for unit pricing information and MW volumes)***

	<u>2001</u> Restated	<u>2000</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Total Revenue . . . . .	\$6,754.2	\$2,375.2	\$4,379.0	184.4%

The increase in total revenue is explained by category below.

	<u>2001</u> Restated	<u>2000</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Electricity and steam revenue . . . . .	\$2,417.5	\$1,696.1	\$ 721.4	42.5%
Sales of purchased power for hedging and optimization . . . . .	<u>3,332.4</u>	<u>369.9</u>	<u>2,962.5</u>	800.9%
Total Electric generation and marketing revenue . . .	<u>\$5,749.9</u>	<u>\$2,066.0</u>	<u>\$3,683.9</u>	178.3%

Electricity and steam revenue increased as we completed construction and brought into operation 9 new baseload power plants, 1 new peaker facility and 1 expansion project. In addition, the 2001 results include the consolidated results of additional facilities that we acquired during 2001 and the full year of production from facilities that we acquired at various times during 2000. Average megawatts in operation of our consolidated plants increased by 146% to 7,984 MW while generation increased by 91%. The overall increase in generation

was partially offset by lower average pricing, which dropped 25% as average realized electric prices, before the effects of hedging, balancing and optimization, declined to \$55.52/MWh in 2001 from \$74.55/MWh in 2000.

Among the long term power contracts we entered into in California in 2001, one had a 10.5 year term, and one had a five year term. Each contract was negotiated in early 2001, commenced on July 1, 2001, and provided for pricing at \$115/megawatt-hour during the first six months which included the peak summer season of 2001 when natural gas costs were very high and blackouts were feared. The contracts then provided for a flat fixed price of \$61.00 and \$75.25, respectively, per megawatt-hour for the balance of the contract terms, when gas prices were expected to return to more normal levels. We concluded that each contract contained two separate elements (1. the six-month period in 2001; and 2. the period commencing January 1, 2002), and consequently we accounted for each element separately. Had we concluded that each contract contained only one element, we would have calculated an average price for the contract as a whole and recognized revenue on a straight-line basis. The impact of the latter approach would have been approximately \$55 less revenue (\$36 less after tax net income) in 2001, and \$55 more revenue (\$36 more after tax net income) in the aggregate over the balance of the contracts. Market circumstances were unique at the time these two contracts were executed, and accordingly, we do not anticipate that we will enter into contracts with similar characteristics in the future in which elements would be separated in the same manner.

Sales of purchased power for hedging and optimization increased during 2001, due to increased hedging, balancing and optimization activity as a result of the growth of Calpine Energy Services ("CES") and our operating plant portfolio during 2001 and also reflects the significant volatility in commodity pricing which led to a high volume of hedging and hedge adjusting activity.

	<u>2001</u> <u>Restated</u>	<u>2000</u> <u>Restated</u>	<u>\$ Change</u>	<u>% Change</u>
Oil and gas sales . . . . .	\$286.5	\$221.9	\$ 64.6	29.1%
Sales of purchased gas for hedging and optimization . .	<u>526.5</u>	<u>87.1</u>	<u>439.4</u>	504.5%
Total Oil and gas production and marketing revenue . .	<u>\$813.0</u>	<u>\$309.0</u>	<u>\$504.0</u>	163.1%

The increase in oil and gas sales relates to increased production and commodity prices in sales to third parties from our reserves in Canada and in the United States.

Sales of purchased gas increased during 2001, due to increased hedging, balancing and optimization activity as a result of the growth of CES and our operating plant portfolio during 2001 and also reflects the significant volatility in commodity pricing which led to a high volume of hedging and hedge adjusting activity.

	<u>2001</u> <u>Restated</u>	<u>2000</u> <u>Restated</u>	<u>\$ Change</u>	<u>% Change</u>
Realized revenue on power and gas trading, net . . . . .	\$ 29.1	\$ —	\$ 29.1	—
Unrealized mark-to-market gain (loss) on trading, net	<u>122.6</u>	<u>—</u>	<u>122.6</u>	—
Total Trading revenue, net . . . . .	<u>\$151.7</u>	<u>\$ —</u>	<u>\$151.7</u>	—

Realized revenue on power and gas trading activity represents the portion of trading contracts actually settled.

We recognized \$98.1 (net of a reserve of \$17.9) in mark-to-market gains on power derivatives in 2001. The reserve is related to gains generated by Enron's insolvency which required earnings recognition for contracts that had previously been exempted from SFAS No. 133 accounting as normal purchases or sales, and which represented the change in fair value of cash flow hedges between the ineffectiveness date and the date of termination. The reserve equals 100% of the net mark-to-market gain that would have otherwise been recognized. The reserve was established due to the uncertainty surrounding the termination and settlement of the Enron contracts and will be reevaluated as we complete the Enron settlement process.

Approximately \$68.5 of the \$98.1 of the mark-to-market gain was recognized in the second quarter of 2001 from entering into a fixed price firm-quantity power sales contract for 2002-2006 with one counterparty in a market area where we did not have generating assets for at least the first six months of the contract. The

contract presented us with an opportunity to establish a commercial relationship with an important customer in a market where we would eventually have generation assets, and we determined there was substantial benefit in executing the agreement for the entire term requested by the counterparty, as opportunities to enter into such a contract may be available infrequently. Because of the structure of the contract, under SFAS No. 133 the contract and the related commodity derivative transactions did not constitute a hedge or a normal purchase or sale. Before taking into account time value of money considerations, the aggregate gain was \$79.9. At September 30, 2001, this gain was locked in as a result of entering into offsetting fixed price power purchases. However, on December 10, 2001, we terminated the portion of those offsetting purchases where Enron was the counterparty, which constituted approximately 30% of the power purchases. We have subsequently completed the process of replacing these contracts. At March 20, 2002, we had replaced 100% of the terminated volume. Our future expansion plans may result in our entry into new markets, which could present similar opportunities, and any resulting power and gas contracts would require similar accounting treatment.

	<u>2001</u> Restated	<u>2000</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Other revenue .....	\$39.6	\$0.2	\$39.4	19,700%

In 2001 other revenue primarily included \$21.3 from PSM, which was acquired in December 2000, \$6.9 in revenues from our WRMS subsidiary and \$5.9 in commissioning services we provided to an unconsolidated construction project.

	<u>2001</u> Restated	<u>2000</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Cost of revenue .....	\$5,520.7	\$1,627.4	\$3,893.3	239.2%

The increase in total cost of revenue is explained by category below.

	<u>2001</u> Restated	<u>2000</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Plant operating expense .....	\$ 325.8	\$199.0	\$ 126.8	63.7%
Royalty expense .....	27.5	32.3	(4.8)	(14.9)%
Purchased power expense for hedging and optimization .....	<u>2,986.6</u>	<u>358.6</u>	<u>2,628.0</u>	732.8%
Total Electric generation and marketing expense . . .	<u>\$3,339.9</u>	<u>\$589.9</u>	<u>\$2,750.0</u>	466.2%

Plant operating expense increased by 63.7% due to additional projects in operation and a 91% growth in generation, but, expressed per MWh of generation, plant operating expenses decreased from \$8.75/MWh to \$7.48/MWh as economies of scale were being realized due to the increase in the average size of our plants.

Royalty expense decreased between periods due to a decrease in revenue at The Geysers geothermal plants due to lower average electric prices.

Purchased power expense for hedging and optimization increased in tandem with sales of purchased power for hedging and optimization due to our greatly increased price hedging, balancing and optimization activities described above.

	<u>2001</u> Restated	<u>2000</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Oil and gas production expense .....	\$ 90.9	\$ 66.4	\$ 24.5	36.9%
Purchased gas expense for hedging and optimization . .	<u>492.6</u>	<u>107.6</u>	<u>385.0</u>	357.8%
Total Oil and gas production and marketing expense . .	<u>\$583.5</u>	<u>\$174.0</u>	<u>\$409.5</u>	235.3%

Oil and gas production expense increased due to an increase in related oil and gas sales and due to increased commodity prices.

Purchased gas expense for hedging and optimization increased due to our greatly increased price hedging, balancing and optimization activities associated with our power generation plants.

	<u>2001</u> Restated	<u>2000</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Fuel expense .....	\$1,171.0	\$602.2	\$568.8	94.5%

Fuel expense increased primarily due to a 91% increase in megawatt hours generated.

	<u>2001</u> Restated	<u>2000</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Depreciation, depletion and amortization expense .....	\$311.3	\$195.9	\$115.4	58.9%

Depreciation, depletion and amortization expense increased due primarily to additional power facilities in consolidated operations during 2001 as compared to 2000, as well as a \$520.4 increase in our oil and gas operating assets.

	<u>2001</u> Restated	<u>2000</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Operating lease expense .....	\$99.5	\$63.5	\$36.0	56.7%

Operating lease expense increased due to a full year of operating lease expense in connection with operating leases entered into or acquired for our Tiverton, Rumford, KIAC, West Ford Flat and Bear Canyon facilities during 2000, and additional operating lease expense for the sale/leaseback transactions of our RockGen, Aidlin and South Point facilities entered into in 2001.

	<u>2001</u> Restated	<u>2000</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Other expense .....	\$15.5	\$2.0	\$13.5	675.0%

Other expense increased primarily due to \$9.3 more expense at PSM, which was acquired in December, 2000.

	<u>2001</u> Restated	<u>2000</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Income from unconsolidated investments in power projects .....	\$(16.2)	\$(28.8)	\$12.6	(43.8)%

The decrease is primarily due to contractual reduction in distributions from the Sumas Power Plant of approximately \$12.9. We also experienced a \$4.1 decrease in income from our Grays Ferry investment and \$2.0 less in income due to the sale of our Bayonne investment in March 2001. This was partially offset by a \$2.0 increase in interest income from loans to power projects related to a note from the Delta Energy Center, LLC. In addition, in 2000 we had a \$2.8 loss from our investment in the Kennedy International Airport Power Plant which was consolidated in 2001 following our acquisition of the remaining 50% interest.

	<u>2001</u> Restated	<u>2000</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Project development expense .....	\$35.9	\$27.6	\$8.3	30.1%

Project development expense increased due to an increase in the number of projects in the early stage of development.

	<u>2001</u> Restated	<u>2000</u> Restated	<u>\$ Change</u>	<u>% Change</u>
General and administrative expense .....	\$153.8	\$97.7	\$56.1	57.4%

The increase was attributable to continued growth in personnel and associated overhead costs necessary to support the overall growth in our operations and due to recent acquisitions, including power facilities and natural gas operations. The growth-induced increase was offset by a decrease in cash bonus accruals to reflect

a higher mix of stock options in our incentive program for management. General and administrative expense expressed per MWh of generation decreased to \$3.53/MWh in 2001 from \$4.30/MWh in 2000.

	<u>2001</u> Restated	<u>2000</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Merger expense . . . . .	\$41.6	\$—	\$41.6	—

The merger expense of \$41.6 in the year ended December 31, 2001, was a result of the pooling-of-interests transaction with Encal Energy Ltd. that closed on April 19, 2001.

	<u>2001</u> Restated	<u>2000</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Interest expense . . . . .	\$198.5	\$81.9	\$116.6	142.4%

Interest expense increased primarily due to a full year of interest expense in 2001 for \$1.0 billion of senior notes issued in 2000, in addition to interest expense on approximately \$4.0 billion, C\$200 million, and £200 million of senior notes issued in 2001. The associated incremental interest expense was partially offset by interest capitalized. In 2001 total capitalized interest was \$498.7 versus \$207.0 in 2000. Capitalized interest increased between years due to the significant increase in our power plant construction program, which offset the slight decrease in our interest capitalization rate due to a decrease in market interest rates.

	<u>2001</u> Restated	<u>2000</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Distributions on trust preferred securities . . . . .	\$62.4	\$45.1	\$17.3	38.4%

The increase is attributable to the issuance of additional trust preferred securities in August 2000, as well as a full period of distributions in 2001 with respect to the January 2000 trust preferred offering and the subsequent exercise of the initial purchasers' option to purchase additional securities.

	<u>2001</u> Restated	<u>2000</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Interest (income) . . . . .	\$(72.5)	\$(40.5)	\$(32.0)	79.0%

This increase is due primarily to the significantly higher cash balances that we maintained as a result of our senior notes and convertible securities offerings in 2001, in addition to \$10.3 interest income in 2001 realized in connection with \$265.6 of PG&E of pre-bankruptcy petition receivables.

	<u>2001</u> Restated	<u>2000</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Other (income) expense, net . . . . .	\$(55.0)	\$0.5	\$(55.5)	11,100%

Other income in 2001 is primarily comprised of approximately \$28.1 related to the settlement and termination of a contract with a gas supplier and \$16.3 related to gains on the sale of oil and gas properties. In addition, \$11.9 represents the gain on extinguishment of debt, primarily a gain of \$13.1 from repurchasing \$122.0 aggregate principal amount of our Zero Coupon Convertible Debentures ("Zero Coupons") at a discount, partially offset by the write off of unamortized deferred financing costs of \$1.2. We also recorded a loss of \$2.3 for the write off of unamortized deferred financing costs resulting from the repayment of \$105 in aggregate outstanding principal amount of the 9¼% Senior Notes Due 2004 and bridge credit facilities entered into in June 2001.

In 2001, we also recorded gains of \$7.2 on the sale of our interests in the Elwood development project and \$11.3 on the sale of our interest in the Bayonne Power Plant including related contingent income recognized as earned thereafter.

These increases were partially offset by a \$17.7 reserve resulting from the nonperformance by a third party in delivering certain emissions reduction credits that we had purchased, and by the sale of the balance of our PG&E pre-bankruptcy petition receivables at a \$9.0 discount.

	<u>2001</u> Restated	<u>2000</u> Restated	<u>\$ Change</u>	<u>% Change</u>
Provision (benefit) for income taxes . . . . .	\$298.7	\$231.5	\$67.2	29.0%

The effective tax rate was approximately 33.7% and 41.0% for 2001 and 2000, respectively, reflecting our expansion into Canada and the United Kingdom and our cross border financings, which reduced our effective tax rates in 2001. However, our taxable income increased by 56.9% in 2001 leading to the increase in the tax provision in 2001.

	<u>2001</u> <u>Restated</u>	<u>2000</u> <u>Restated</u>	<u>\$ Change</u>	<u>% Change</u>
Cumulative effect of a change in acct. principle, net of tax .....	\$1.0	\$—	\$1.0	—

In 2001, the \$1.0 of additional income (net of tax of \$0.7) is due to the adoption of SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities.”

	<u>2001</u> <u>Restated</u>	<u>2000</u> <u>Restated</u>	<u>\$ Change</u>	<u>% Change</u>
Net income .....	623.5	369.1	254.4	68.9%

The increase in net income reflects a \$485.7 increase in gross profit which primarily reflects a 91% increase in generation, which was partially offset by a 22% decrease in average spark spread per MWh, and also reflects \$151.7 of trading revenue in 2001 versus none in 2000. The increase in gross profit was partially offset by \$56.1 higher general and administrative expense, \$41.6 of merger expense associated with the Encal acquisition, \$116.6 higher interest expense and \$67.2 higher income tax expense in 2001. These higher expense items were mitigated by \$55.5 higher other income and \$32.0 higher interest income in 2001.

(1) See Note 2 of the Notes to Consolidated Financial Statements regarding the restatement of financial statements.

### Liquidity and Capital Resources

*General* — Beginning in the latter half of 2001, and continuing through 2002 to date, there has been a significant contraction in the availability of capital for participants in the energy sector. This was due to a range of factors, including uncertainty arising from the collapse of Enron Corp. and a perceived near-term surplus supply of electric generating capacity. These factors continued in 2002, during which contracting credit markets and decreased spark spreads adversely impacted our liquidity and earnings. While we were able to access the capital and bank credit markets in the first half of 2002, as discussed below, it was on significantly different terms than in the past. We recognize that terms of financing available to us in the future may not be attractive. To protect against this possibility and due to current market conditions, we scaled back our capital expenditure program for 2002 and 2003 to enable us to conserve our available capital resources.

To date, we have obtained cash from our operations; borrowings under our term loan and revolving credit facilities; issuance of debt, equity, trust preferred securities and convertible debentures; proceeds from sale/leaseback transactions, sale of certain assets and project financing. We have utilized this cash to fund our operations, service or prepay debt obligations, fund acquisitions, develop and construct power generation facilities, finance capital expenditures, support our hedging, balancing, optimization and trading activities at CES, and meet our other cash and liquidity needs. Our business is capital intensive. Our ability to capitalize on growth opportunities is dependent on the availability of capital on attractive terms; the availability of such capital in today’s environment is uncertain. Our strategy is also to reinvest our cash from operations into our business development and construction program or use it to reduce debt, rather than to pay cash dividends.

Factors that could affect our liquidity and capital resources are also discussed in Item 1. “Business — Risk Factors”.

*Cash Flow Activities* — The following table summarizes our cash flow activities for the periods indicated:

	Years Ended December 31,		
	2002	2001	2000
		Restated (1) (In thousands)	Restated (1)
Beginning cash and cash equivalents .....	\$ 1,594,144	\$ 664,722	\$ 349,371
Net cash provided by:			
Operating activities .....	1,068,466	423,569	875,751
Investing activities .....	(3,837,827)	(7,240,655)	(3,877,187)
Financing activities .....	1,757,396	7,750,177	3,316,787
Effect of exchange rates changes on cash and cash equivalents .....	(2,693)	(3,669)	—
Net increase (decrease) in cash and cash equivalents .....	(1,014,658)	929,422	315,351
Ending cash and cash equivalents .....	<u>\$ 579,486</u>	<u>\$ 1,594,144</u>	<u>\$ 664,722</u>

(1) See Note 2 of the Notes to Consolidated Financial Statements regarding the restatement of financial statements.

Operating activities for 2002 provided net cash of \$1,068.5 million, a 152% increase from 2001, consisting primarily of a \$327.8 million decrease in operating assets due primarily to the sale of our remaining pre-bankruptcy petition accounts receivable from PG&E in January 2002 for approximately \$245.5 million (See Note 23 to the Notes to Consolidated Financial Statements), a \$151.4 million increase in operating liabilities, \$542.2 million of depreciation, depletion and amortization, \$404.7 million of equipment cancellation and asset impairment charge, and \$56.4 million of development cost write-offs. This was partially offset by a \$340.9 million decrease in net derivative liabilities and other comprehensive income related to derivatives, and \$215.4 million of gains on assets sales and retirement of debt.

Investing activities for 2002 consumed net cash of \$3.8 billion, primarily due to \$4.0 billion for construction costs and capital expenditures including gas turbine generator costs and associated capitalized interest, \$68.1 million of advances to joint ventures including associated capitalized interest for investments in power projects under construction, and \$105.2 million of capitalized project development costs including associated capitalized interest. This was partially offset by \$400.3 million in proceeds from asset sales, and \$26.1 million from derivatives not designated as hedges. The decrease in cash used in investing activities in 2002 is primarily due to scale back of our construction and acquisition program.

Financing activities for 2002 provided \$1.8 billion of net cash consisting of \$1.3 from borrowings under notes payable and lines of credit, \$100 million of proceeds from our issuance of Convertible Senior Notes Due 2006, \$725.1 million in additional project financing, \$751.8 million from the issuance of common stock, and \$169.7 million from our Canadian income trust offering. This was offset by \$1.3 billion of repayments on various credit facilities, and \$42.8 million of financing costs. The decrease in cash provided from financing activities in 2002 is primarily due to the suspension of certain capital requiring activities and industry wide credit restrictions.

We have made certain reclassifications in our financial statements, including certain presentation changes in our Restated Consolidated Statements of Cash Flows for 2000 and 2001, to reflect the restatements discussed in Note 2 to the Consolidated Financial Statements as well as other reclassifications to conform to the current year presentation.

In the restated 2001 statement we reduced “deferred income taxes, net” in “cash flows from operating activities” by \$143.1 million and increased “acquisitions, net of cash acquired” in “cash flows from investing activities” by \$143.1 million. This was the amount of gross-up of deferred taxes on contingent purchase price premium paid in 2001 in connection with the SkyGen acquisition.

We continue to evaluate current and forecasted cash flow as a basis for funding operating requirements and capital expenditures. In November 2003 and 2004 our \$1.0 billion and \$2.5 billion secured revolving construction financing facilities will mature, requiring us to refinance this indebtedness. At December 31, 2002, there was \$970.1 million and \$2,469.6 million outstanding, respectively, under these facilities. In May 2003, our \$1.0 billion secured working capital revolving credit facilities will mature and the \$1.0 billion secured term credit facility will mature in May 2004. At December 31, 2002, we had \$340.0 million in funded borrowings under the revolving credit facilities and \$949.6 million in funded borrowings outstanding under the term loan facility. These facilities will also have to be refinanced. We believe that, if we are able to refinance these facilities, we will have sufficient liquidity from cash flow from operations, borrowings available under lines of credit, access to sale/leaseback and project financing markets, sale of certain assets and cash balances to satisfy all obligations under our other outstanding indebtedness, and to fund anticipated capital expenditures and working capital requirements for the next twelve months.

*Customers* — As of December 31, 2002, we had collection exposures after established reserves from certain of our counterparties as follows: \$21.1 million from the California Independent System Operator Corporation and Automated Power Exchange, Inc.; approximately \$4.8 million and \$3.7 million, with two subsidiaries of Sierra Pacific Resources Company, Nevada Power Company and Sierra Pacific Power, respectively; \$5.4 million with NRG Power Marketing, Inc and \$40.1 million with Aquila Merchant Services, Inc. and Aquila. While we cannot predict the likelihood of default by our customers, we are continuing to closely monitor our positions and will adjust the values of the reserves as conditions dictate. Based on our legal analysis, we do not have any net collection exposure to Enron and its affiliates. See Note 23 to the Consolidated Financial Statements for more information.

*Letter of Credit Facilities* — At December 31, 2002 and 2001, we had approximately \$685.6 million and \$642.5 million respectively, in letters of credit outstanding under various credit facilities to support CES risk management, and other operational and construction activities. Of the total letters of credit outstanding, \$573.9 million and \$373.2 million, respectively, were issued under the corporate revolving credit facilities at December 31, 2002 and 2001.

*CES Margin Deposits and Other Credit Support* — As of December 31, 2002 and 2001, CES had deposited net amounts of \$25.2 million and \$345.5 million, respectively, in cash as margin deposits with third parties related to its business activities and had letters of credit outstanding to support CES risk management activities of \$106.1 million and \$236.1 million, respectively.

The amount of credit support required to support CES's operations is a function primarily of the changes in fair value of commodity contracts that CES has entered into and our credit rating. Since December 31, 2001, the amount of credit support provided by us for CES transactions has declined, largely due to the reduction of CES's activities as well as changes in commodity prices in late 2002 as compared with late 2001. While we believe that we have adequate liquidity to support CES' operations at this time, it is difficult to predict future developments and the amount of credit support that we may need to provide as part of our business operations.

*Working Capital* — At December 31, 2002 we had a negative working capital balance (current assets minus current liabilities) of \$1,331.1 million. This was primarily caused by \$1,651.5 million of debt, including balances outstanding under our \$1 billion construction revolving credit facility and our \$400 million working capital revolving credit facility that we intend to refinance or extend. Until such time as the debt is refinanced or extended, we are classifying it as current.

*Revised Capital Expenditure Program* — Following a comprehensive review of our power plant development program, we announced in January 2002 the adoption of a revised capital expenditure program, which contemplated the completion of 27 power projects (representing 15,200 MW) then under construction. Seventeen of these facilities have subsequently achieved full or partial commercial operation as of December 31, 2002. Construction of advanced stage development projects is expected to proceed only when there is an established market need for additional generating resources at prices that will allow us to meet our investment criteria, and when capital may again become available to us on attractive terms. Further, our entire

development and construction program is flexible and subject to continuing review and revision based upon such criteria.

On March 12, 2002, we announced a new turbine program that reduced previously forecasted capital spending by approximately \$1.2 billion in 2002 and \$1.8 billion in 2003. The revision includes adjusted timing of turbine delivery and related payment schedules and also cancellation of some orders. As a result of these turbine cancellations and other equipment cancellations, we recorded a pre-tax charge of \$168.5 million in the first quarter of 2002.

During the fourth quarter of 2002, we entered into restructured agreements with our major gas and steam turbine manufacturers, generally extending the time frame for us to decide whether to proceed with or cancel our existing orders for 87 gas turbines and 44 steam turbines. The new agreements reduce our future capital commitments by approximately \$3.4 billion and provide greater flexibility to match equipment commitments with our revised construction and development program. In recognition of probable market and capital limitations, we recorded a pre-tax charge of approximately \$207.4 million in the fourth quarter of 2002, which represented all costs associated with the potential cancellation of all of these 87 gas turbines and 44 steam turbines.

*Uses and Sources of Funding* — Our estimated uses of funds for 2003 are as follows: construction costs of \$1.3 billion, maintenance capital of \$0.3 billion, cash lease payments of \$0.3 billion and \$0.3 billion for future turbine capital. These outflows will be funded primarily through cash on hand (cash and cash equivalents and current portion of restricted cash) of \$0.7 billion and an estimated \$0.6 billion of 2003 operating cash flow. The other projected sources of funding will include \$0.8 billion from contract securitization, \$0.6 billion from asset sales, \$0.4 billion from construction project financing, \$0.4 billion from lease or other project financing and \$0.1 billion from a secondary offering of part of our interests in the Canadian Power Income Fund. Actual costs for the projected use of funds identified above, and net proceeds from the projected sources of funds identified above could vary from those estimates, potentially in material respects. In addition, the timing is difficult to predict and we may not be able to complete the financings or they may be able to complete them only on less favorable terms than currently anticipated. The above assumes the refinancing of the corporate revolving line of credit and the refinancing or extension of the revolving construction financing facility, which are both expiring in 2003. Factors that could affect the accuracy of these estimates include the factors identified at the beginning of this section and under “Risk Factors” in Item 1. “Business.”

*Capital Availability* — Access to capital for many in the energy sector, including us, has been restricted since late 2001. While we were able in the first half of 2002 to access the capital and bank credit markets, in this new environment, it was on significantly different terms than in the past, in particular our senior working capital facility has been secured by certain of our assets and equity interests. The terms of financing available to us now and in the future may not be attractive to us and the timing of the availability of capital is uncertain and is dependent, in part, on market conditions that are difficult to predict and are outside of our control. We were able to raise the following capital in 2002:

- Up to \$232.0 million of vendor financing with Siemens Westinghouse Power Corporation in January 2002
- Proceeds of \$734.3 million (after underwriting fees) from a public offering of common stock of 66 million shares at \$11.50 per share completed in April 2002; proceeds were used to repay debt and for general corporate purposes
- \$50.0 million net funding for 9 California peaker facilities (\$100.0 million drawn in May 2002 and \$50.0 million repaid in August 2002)
- In March 2002, we secured our previously unsecured working capital credit facility and increased it to \$2.0 billion. Subsequently we increased our two-year secured bank term loan from \$600.0 million to

\$1.0 billion (subsequently permanently reduced to \$949.6 million) and simultaneously reduced our secured corporate revolving credit facilities to \$1.0 billion, inclusive of letter of credit usage

- \$106.0 million non-recourse project financing for construction of Blue Spruce Energy Center completed in August 2002
- Canadian Power Income Fund in August and September 2002 and February 2003 — for a total of US \$269.6 million (Cdn \$417.8 million) including our secondary offering of Warranted Units in February 2003
- Secured project financings of \$50.0 million and \$37.0 million, respectively, for the Newark and Parlin Power Plants completed in December 2002

*Asset Sales* — As a result of the significant contraction in the availability of capital for participants in the energy sector, we have adopted a strategy of conserving our core strategic assets and disposing of certain less strategically important assets, which serves primarily to strengthen our balance sheet through repayment of debt. Set forth below are the completed asset disposals:

On August 29, 2002, we completed the sale of certain oil and gas properties (“Medicine River properties”) located in central Alberta to NAL Oil and Gas Trust and another institutional investor for Cdn\$125.0 million (US\$80.1 million). As a result of the sale, we recognized a pre-tax gain of \$21.9 million.

On October, 1 2002, we completed the sale of substantially all of our British Columbia oil and gas properties to Calgary, Alberta-based Pengrowth Corporation for gross proceeds of approximately Cdn\$387.5 million (US\$244.3 million). Of the total consideration, we received US\$155.9 million in cash. The remaining US\$88.4 million was paid by Pengrowth Corporation’s purchase in the open market (for an aggregate purchase price of US\$88.4 million) and delivery to us of US\$203.2 million in aggregate principal amount of our debt securities. As a result of the transaction, we recorded a US\$37.4 million pre-tax gain on the sale of the properties and a gain on the extinguishment of debt of US\$114.8 million. We used approximately US\$50.4 million of cash proceeds to repay amounts outstanding under our US\$1.0 billion term loan.

On October 31, 2002, we sold all of our oil and gas properties in Drake Bay Field located in Plaquemines Parish, Louisiana for approximately \$3.0 million to Goldking Energy Corporation. As a result of the sale, we recognized a pre-tax loss of \$0.02 million.

On December 16, 2002, we completed the sale of the 180-megawatt DePere Energy Center in DePere, Wisconsin. The facility was sold to Wisconsin Public Service for \$120.4 million, which included \$72.0 million in cash at closing and a \$48.4 million payment due in December 2003. As a result of the sale, we recognized a pre-tax gain of \$35.8 million. On December 17, 2002, we sold our right to the December 2003 payment to a third party for \$46.3 million and recognized a pre-tax loss of \$2.1 million.

*Credit Considerations* — On December 14, 2001, Moody’s downgraded our long-term senior unsecured debt from Baa3 (its lowest investment grade rating) to Ba1 (its highest non-investment grade rating). On April 2, 2002, Moody’s further downgraded our long-term senior unsecured debt from Ba1 to B1. We remain on credit watch with negative implications at Moody’s.

On December 19, 2001, Fitch downgraded our long-term senior unsecured debt from BBB– (its lowest investment grade rating) to BB+ (its highest non-investment grade rating). On March 12, 2002, Fitch further downgraded our long-term senior unsecured debt from BB+ to BB. On December 9, 2002, Fitch downgraded our long-term senior unsecured debt from BB to B+.

On March 25, 2002, Standard & Poor’s downgraded our corporate credit rating from BB+ (its highest non-investment grade rating) to BB and assigned a rating of B+ to our long-term senior unsecured debt. On

May 17, 2002, Standard and Poor's issued a rating of BBB- (its lowest investment grade level) on our secured credit facilities. We remain on credit watch with negative implications at Standard and Poor's.

Many other issuers in the power generation sector have also been downgraded by one or more of the ratings agencies during this period. Such downgrades can have a negative impact on our liquidity by reducing attractive financing opportunities and increasing the amount of collateral required by trading counterparties.

*Performance Indicators* — We believe the following factors are important in assessing our ability to continue to fund our growth in the capital markets: (a) our debt-to-capital ratio; (b) various interest coverage ratios; (c) our credit and debt ratings by the rating agencies; (d) the trading prices of our senior notes in the capital markets; (e) the price of our common stock on The New York Stock Exchange; (f) our anticipated capital requirements over the coming quarters and years; (g) the profitability of our operations; (h) our cash balances and remaining capacity under existing revolving credit construction and general purpose credit facilities; (i) compliance with covenants in existing debt facilities; (j) progress in raising new or replacement capital; and (k) the stability of future contractual cash flows. We believe that our ability to complete the financing transactions described above in difficult conditions affecting the market, and our sector, in general demonstrate our ability to have access to the capital markets on acceptable terms in the future, although availability of capital has tightened significantly throughout the power generation industry and, therefore, there can be no assurance that we will have access to capital in the future as and when we may desire.

*Off-Balance Sheet Commitments* — In accordance with SFAS No. 13 and SFAS No. 98, "Accounting for Leases" our operating leases are not reflected on our balance sheet. We entered into sale/leaseback transactions involving our Tiverton and Rumford projects in December 2000 and our South Point and RockGen projects in October 2001. All counterparties in these transactions are third parties that are unrelated to us. The sale/leaseback transactions utilize special-purpose entities formed by the equity investors with the sole purpose of owning a power generation facility. Some of our operating leases contain customary restrictions on dividends, additional debt and further encumbrances similar to those typically found in project finance debt instruments. We guarantee \$1.8 billion of the total future minimum lease payments of our consolidated subsidiaries related to our operating leases. We have no ownership or other interest in any of these special-purpose entities.

In accordance with Accounting Principles Board ("APB") Opinion No. 18, "The Equity Method of Accounting For Investments in Common Stock" and FASB Interpretation No. 35, "Criteria for Applying the Equity Method of Accounting for Investments in Common Stock (An Interpretation of APB Opinion No. 18)," the debt on the books of our unconsolidated investments in power projects is not reflected on our balance sheet (see Note 9 to the Notes to Consolidated Financial Statements). At December 31, 2002, investee debt was approximately \$639.3 million. Based on our pro rata ownership share of each of the investments, our share would be approximately \$238.6 million. However, all such debt is non-recourse to us. For the Aries Power Plant construction debt, we and Aquila Energy, a wholly owned subsidiary of UtiliCorp United, provided support arrangements until construction was completed to cover any cost overruns.

We have guaranteed the principal payment of \$2.7 billion and \$2.6 billion, respectively, of senior notes as of December 31, 2002, and 2001, for two wholly-owned finance subsidiaries of Calpine, Calpine Canada Energy Finance ULC and Calpine Canada Energy Finance II ULC. In addition, as of December 31, 2002, we have guaranteed the payment of \$50.0 million of project financing for our wholly-owned subsidiary, Calpine California Energy Finance, LLC. As of December 31, 2002, we have guaranteed \$301.0 million and \$388.9 million, respectively of project financing for the Broad River Energy Center and Pasadena Power Plant and \$300.0 million and \$387.1 million, respectively, as of December 31, 2001 for these power plants. All of the guaranteed debt is recorded on our consolidated balance sheet.

*Contractual Obligations* — Our contractual obligations as of December 31, 2002, are as follows (in thousands):

<u>Contractual Obligations</u>	<u>2003</u>	<u>2004</u>	<u>2005</u>	<u>2006</u>	<u>2007</u>	<u>Thereafter</u>	<u>Total</u>
Notes payable and borrowings under lines of credit and term loan . . . . .	\$ 340,703	\$ 951,841	\$ 4,047	\$ 161	\$ 171	\$ 1,594	\$ 1,298,517
Capital lease obligation . . . . .	3,502	3,995	4,416	5,468	5,980	177,813	201,174
Construction/project financing	1,307,291	2,493,712	19,192	22,202	34,152	642,764	4,519,313
Convertible Senior Notes . . . . .	—	—	—	1,200,000	—	—	1,200,000
Senior Notes . . . . .	—	—	249,420	421,571	400,889	5,822,921	6,894,801
Total operating lease . . . . .	255,784	226,914	209,909	196,069	193,491	1,928,165	3,010,332
Turbine commitments . . . . .	427,848	153,339	19,596	—	—	—	600,783
HIGH TIDES . . . . .	—	—	—	—	—	1,153,500	1,153,500
Total . . . . .	<u>\$2,335,128</u>	<u>\$3,829,801</u>	<u>\$506,580</u>	<u>\$1,845,471</u>	<u>\$634,683</u>	<u>\$9,726,757</u>	<u>\$18,878,420</u>

See Notes 13 through 19 of the Notes to Consolidated Financial Statements for more information on the debt, HIGH TIDES and capital lease obligations outstanding in 2001 and 2002. See Note 26 of the Consolidated Financial Statements for more information on our operating leases and turbine commitments. We have substantial flexibility to either proceed with or cancel our turbine orders as conditions warrant. Holders have the right to require us to repurchase all or a portion of the Convertible Senior Notes on December 26, 2004, at 100% of their principal amount plus any accrued and unpaid interest.

*Commercial Commitments* — Our primary commercial obligations as of December 31, 2002, are as follows (in thousands):

<u>Commercial Commitments</u>	<u>Amounts of Commitment Expiration Per Period</u>						
	<u>Total Amounts Committed</u>	<u>2003</u>	<u>2004</u>	<u>2005</u>	<u>2006</u>	<u>2007</u>	<u>Thereafter</u>
Guarantee of subsidiary debt . . . . .	\$3,396,656	\$161,268	\$ 18,597	\$ 13,086	\$15,528	\$152,618	\$3,035,559
Standby letters of credit . . . . .	685,606	622,178	—	63,428	—	—	—
Surety bonds . . . . .	72,267	2,090	33,366	—	—	—	36,811
Guarantee of subsidiary operating lease payments . . . . .	<u>1,848,550</u>	<u>111,070</u>	<u>96,688</u>	<u>83,169</u>	<u>81,772</u>	<u>82,487</u>	<u>1,393,364</u>
Total . . . . .	<u>\$6,003,079</u>	<u>\$896,606</u>	<u>\$148,651</u>	<u>\$159,683</u>	<u>\$97,300</u>	<u>\$235,105</u>	<u>\$4,465,734</u>

Our commercial commitments primarily include guarantee of subsidiary debt, standby letters of credit, surety bonds and guarantee of subsidiary operating lease payments. The debt guarantees consist of parent guarantees for the finance subsidiaries, project financing for the Broad River Energy Center and the Pasadena Power Plant and for the funding for the peaker facilities. The debt guarantees and operating lease payments are also included in the contractual obligations table above. We also issue guarantees for normal course of business activities.

### Performance Metrics

In understanding our business, we believe that certain non-GAAP financial measures and other performance metrics are particularly important. These are described below, beginning with the non-GAAP financial measures:

- *Average gross profit margin based on non-GAAP revenue and non-GAAP cost of revenue.* A high percentage of our revenue in 2001 and, to a somewhat lesser extent, in 2002 consisted of CES hedging, balancing and optimization activity undertaken primarily to enhance the value of our generating assets (see “Marketing, Hedging, Optimization, and Trading” subsection of the Business Section). CES’s hedging, balancing and optimization activity is primarily accomplished by buying

and selling electric power and buying and selling natural gas or by entering into gas financial instruments such as exchange-traded swaps or forward contracts. Under SAB No. 101 and EITF No. 99-19, we must show the purchases and sales of electricity and gas for hedging, balancing and optimization activities (non-trading activities) on a gross basis in our statement of operations when we act as a principal, take title to the electricity and gas we purchase for resale, and enjoy the risks and rewards of ownership. This is notwithstanding the fact that the net gain or loss on certain financial hedging instruments, such as exchange-traded natural gas price swaps, is shown as a net item in our GAAP financials and that pursuant to EITF No. 02-3, trading activity is now shown net in our Statements of Operations under trading revenue, net, for all periods presented. Because of the inflating effect on revenue of much of our hedging, balancing and optimization activity, we believe that revenue levels and trends do not reflect our performance as accurately as gross profit, and that it is analytically useful for investors to look at our results on a non-GAAP basis with all hedging, balancing and optimization activity netted. This analytical approach nets the sales of purchased power for hedging and optimization with purchased power expense for hedging and optimization and includes that net amount as an adjustment to E&S revenue for our generation assets. Similarly, we believe that it is analytically useful for investors to net the sales of purchased gas for hedging and optimization with purchased gas expense for hedging and optimization and include that net amount as an adjustment to fuel expense. This allows us to look at all hedging, balancing and optimization activity consistently (net presentation) and better understand our performance trends. It should be noted that in this non-GAAP analytical approach, total gross profit does not change from the GAAP presentation, but the gross profit margins as a percent of revenue do differ from corresponding GAAP amounts because the inflating effects on our GAAP revenue of hedging, balancing and optimization activities are removed.

Other performance metrics are described below:

- *Average availability and average capacity factor or operating rate.* Availability represents the percent of total hours during the period that our plants were available to run after taking into account the downtime associated with both scheduled and unscheduled outages. The capacity factor, sometimes called operating rate, is calculated by dividing (a) total megawatt hours generated by our power plants (excluding peakers) by the product of multiplying (b) the weighted average megawatts in operation during the period by (c) the total hours in the period. The capacity factor is thus a measure of total actual generation as a percent of total potential generation. If we elect not to generate during periods when electricity pricing is too low or gas prices too high to operate profitably, the capacity factor will reflect that decision as well as both scheduled and unscheduled outages due to maintenance and repair requirements.
- *Average heat rate for gas-fired fleet of power plants expressed in Btu's of fuel consumed per KWh generated.* We calculate the average heat rate for our gas-fired power plants (excluding peakers) by dividing (a) fuel consumed in Btu's by (b) KWh generated. The resultant heat rate is a measure of fuel efficiency, so the lower the heat rate, the better. We also calculate a "steam-adjusted" heat rate, in which we adjust the fuel consumption in Btu's down by the equivalent heat content in steam or other thermal energy exported to a third party, such as to steam hosts for our cogeneration facilities. Our goal is to have the lowest average heat rate in the industry.
- *Average all-in realized electric price expressed in dollars per MWh generated.* Our risk management and optimization activities are integral to our power generation business and directly impact our total realized revenues from generation. Accordingly, we calculate the all-in realized electric price per MWh generated by dividing (a) adjusted electricity and steam revenue, which includes capacity revenues, energy revenues, thermal revenues and the spread on sales of purchased electricity for hedging, balancing, and optimization activity, by (b) total generated MWh's in the period.
- *Average cost of natural gas expressed in dollars per millions of Btu's of fuel consumed.* Our risk management and optimization activities related to fuel procurement directly impact our total fuel expense. The fuel costs for our gas-fired power plants are a function of the price we pay for fuel

purchased and the results of the fuel hedging, balancing, and optimization activities by CES. Accordingly, we calculate the cost of natural gas per millions of Btu's of fuel consumed in our power plants by dividing (a) adjusted fuel expense which includes the cost of fuel consumed by our plants (adding back cost of intercompany "equity" gas from Calpine Natural Gas, which is eliminated in consolidation), and the spread on sales of purchased gas for hedging, balancing, and optimization activity by (b) the heat content in millions of Btu's of the fuel we consumed in our power plants for the period.

- *Average spark spread expressed in dollars per MWh generated.* Our risk management activities focus on managing the spark spread for our portfolio of power plants, the spread between the sales price for electricity generated and the cost of fuel. We calculate the spark spread per MWh generated by subtracting (a) adjusted fuel expense from (b) adjusted E&S revenue and dividing the difference by (c) total generated MWh in the period.

The table below presents, side-by-side, both our GAAP and non-GAAP netted revenue, costs of revenue and gross profit showing the purchases and sales of electricity and gas for hedging, balancing and optimization activity on a net basis. It also shows the other performance metrics discussed above.

	GAAP Presentation			Non-GAAP Netted Presentation		
	Year Ended December 31,			Year Ended December 31,		
	2002	2001	2000	2002	2001	2000
		Restated (1)	Restated (1)			
			(In thousands)			
<b>Revenue, Cost of Revenue and Gross Profit</b>						
Revenue:						
Electric generation and marketing revenue						
Electricity and steam revenue(3) . . . . .	\$3,280,291	\$2,417,481	\$1,696,066	\$3,807,837	\$2,763,315	\$1,707,328
Sales of purchased power for hedging and optimization(3) . . . . .	<u>3,145,991</u>	<u>3,332,412</u>	<u>369,911</u>	<u>—</u>	<u>—</u>	<u>—</u>
Total electric generation and marketing revenue . . . . .	6,426,282	5,749,893	2,065,977	3,807,837	2,763,315	1,707,328
Oil and gas production and marketing revenue						
Oil and gas production sales . . . . .	121,227	286,519	221,883	121,227	286,519	221,883
Sales of purchased gas for hedging and optimization(3) . . . . .	<u>870,466</u>	<u>526,517</u>	<u>87,119</u>	<u>—</u>	<u>—</u>	<u>—</u>
Total oil and gas production and marketing revenue . . . . .	991,693	813,036	309,002	121,227	286,519	221,883
Trading revenue, net						
Realized net revenue on power and gas trading, net . . . . .	26,090	29,145	—	26,090	29,145	—
Unrealized mark-to-market gain (loss) on power and gas transactions, net . . . . .	<u>(4,605)</u>	<u>122,593</u>	<u>—</u>	<u>(4,605)</u>	<u>122,593</u>	<u>—</u>
Total trading revenue, net . . . . .	21,485	151,738	—	21,485	151,738	—
Other revenue . . . . .	<u>18,439</u>	<u>39,561</u>	<u>199</u>	<u>18,439</u>	<u>39,561</u>	<u>199</u>
Total revenue . . . . .	<u>7,457,899</u>	<u>6,754,228</u>	<u>2,375,178</u>	<u>3,968,988</u>	<u>3,241,133</u>	<u>1,929,410</u>

	GAAP Presentation			Non-GAAP Netted Presentation		
	Year Ended December 31,			Year Ended December 31,		
	2002	2001	2000	2002	2001	2000
		Restated (1)	Restated (1)			
			(In thousands)			
Cost of revenue:						
Electric generation and marketing expense						
Plant operating expense . . . . .	510,929	325,847	198,964	510,929	325,847	198,964
Royalty expense . . . . .	17,615	27,493	32,326	17,615	27,493	32,326
Purchased power expense (2)	<u>2,618,445</u>	<u>2,986,578</u>	<u>358,649</u>	<u>—</u>	<u>—</u>	<u>—</u>
Total electric generation and marketing expense . . . . .	3,146,989	3,339,918	589,939	528,544	353,340	231,290
Oil and gas production and marketing expense						
Oil and gas production expense . . . . .	97,895	90,882	66,369	97,895	90,882	66,369
Purchased gas expense (2) . . . . .	<u>821,065</u>	<u>492,587</u>	<u>107,591</u>	<u>—</u>	<u>—</u>	<u>—</u>
Total oil and gas production and marketing expense . . . . .	918,960	583,469	173,960	97,895	90,882	66,369
Total fuel expense . . . . .	1,791,930	1,170,977	602,165	1,742,529	1,137,047	622,637
Depreciation, depletion and amortization expense . . . . .	459,465	311,302	195,863	459,465	311,302	195,863
Operating lease expense . . . . .	111,022	99,519	63,463	111,022	99,519	63,463
Other expense . . . . .	<u>12,593</u>	<u>15,548</u>	<u>2,019</u>	<u>12,593</u>	<u>15,548</u>	<u>2,019</u>
Total cost of revenue . . . . .	6,440,959	5,520,733	1,627,409	2,952,048	2,007,638	1,181,641
Gross profit . . . . .	<u>\$1,016,940</u>	<u>\$1,233,495</u>	<u>\$ 747,769</u>	<u>\$1,016,940</u>	<u>\$1,233,495</u>	<u>\$ 747,769</u>
Gross profit margin . . . . .	14%	18%	31%	26%	38%	39%

<b>Non-GAAP Netted Presentation</b>		
<b>Year Ended December 31,</b>		
<b>2002</b>	<b>2001</b>	<b>2000</b>
<b>(In thousands)</b>		

**Other Non-GAAP Performance Metrics**

Average availability and capacity factor:

Average availability .....	92%	93%	94%
Average capacity factor or operating rate based on total hours (excluding peakers) .....	67%	72%	72%

Average heat rate for gas-fired power plants (excluding peakers)  
(Btu's/kWh):

Not steam adjusted .....	7,912	8,203	9,294
Steam adjusted .....	7,239	7,398	7,816

Average all-in realized electric price:

Adjusted Electricity and steam revenue before discontinued operations (in thousands) .....	\$3,807,837	\$2,763,315	\$1,707,328
Electricity and steam revenue from discontinued operations ...	<u>16,915</u>	<u>17,112</u>	<u>7,178</u>
Adjusted electricity and steam revenue (in thousands) .....	3,824,752	2,780,427	1,714,506
MWh generated (in thousands) .....	74,542	43,542	22,750
Average all-in realized electric price per MWh .....	\$ 51.31	\$ 63.86	\$ 75.36

Average cost of natural gas:

Cost of oil and natural gas burned by power plants (in thousands) .....	\$1,742,529	\$1,137,047	\$ 622,637
Fuel cost elimination .....	180,375	99,854	56,052
Fuel expense from discontinued operations .....	<u>10,416</u>	<u>6,455</u>	<u>3,515</u>
Adjusted fuel expense .....	\$1,933,320	\$1,243,356	\$ 682,204
MMBtu of fuel consumed by generating plants (in thousands)	524,840	297,454	150,669
Average cost of natural gas per MMBtu .....	\$ 3.68	\$ 4.18	\$ 4.53
MWh generated (in thousands) .....	74,542	43,542	22,750
Average cost of oil and natural gas burned by power plants per MWh .....	\$ 25.94	\$ 28.56	\$ 29.99

Average spark spread:

Adjusted electricity and steam revenue (in thousands) .....	\$3,824,752	\$2,780,427	\$1,714,506
Less: Adjusted fuel expense (in thousands) .....	<u>\$1,933,320</u>	<u>\$1,243,356</u>	<u>\$ 682,204</u>
Spark spread (in thousands) .....	\$1,891,432	\$1,537,071	\$1,032,302
MWh generated (in thousands) .....	74,542	43,542	22,750
Average spark spread per MWh .....	\$ 25.37	\$ 35.30	\$ 45.38

The non-GAAP presentation above also facilitates a look at the total "trading" activity impact on gross profit. Prior to 2001, we did not engage in trading activities; consequently, no trading revenues were recognized

in 2000. For the years ended December 31, 2002 and 2001, trading revenue, net consisted of (dollars in thousands):

		<u>2002</u>	<u>2001</u> Restated (1)
<b>ELECTRICITY</b>			
Realized gain (loss)	Realized revenue on power trading transactions, net .....	\$ 12,175	\$ 9,926
Unrealized	Unrealized mark-to-market gain (loss) on power transactions, net .....	<u>8,040</u>	<u>98,268</u>
Subtotal		<u>\$ 20,215</u>	<u>\$108,194</u>
<b>GAS</b>			
Realized gain (loss)	Realized revenue on gas trading transactions, net	\$ 13,915	\$ 19,219
Unrealized	Unrealized mark-to-market gain (loss) on gas transactions, net .....	<u>(12,645)</u>	<u>24,325</u>
Subtotal		<u>\$ 1,270</u>	<u>\$ 43,544</u>

	<u>2002</u>	Percent of Gross Profit	<u>2001</u>	Percent of Gross Profit
Total trading activity gain (loss) .....	\$21,485	2.1%	\$151,738	12.3%
Realized gain .....	\$26,090	2.6%	\$ 29,145	2.4%
Unrealized (mark-to-market) gains (loss) (2) .....	\$(4,605)	(0.5)%	\$122,593	9.9%

- (1) See Note 2 of Notes to Consolidated Financial Statements regarding the restatement of financial statements.
- (2) For the year ended December 31, 2002 and 2001, the mark-to-market gains shown above as "trading" activity include hedge ineffectiveness as discussed in Note 24.
- (3) Following is a reconciliation of GAAP to non-GAAP presentation further to the narrative set forth under this Performance Metrics section: (\$ in thousands)

	<u>GAAP Balance</u>	<u>To Net Hedging, Balancing &amp; Optimization Activity</u>	<u>Netted Non-GAAP Balance</u>
<b>2002</b>			
Electricity and steam revenue .....	\$3,280,291	\$ 527,546	\$3,807,837
Sales of purchased power .....	3,145,991	(3,145,991)	—
Sales of purchased gas .....	870,466	(870,466)	—
Purchased power expense .....	2,618,445	(2,618,445)	—
Purchased gas expense .....	821,065	(821,065)	—
Fuel expense .....	1,791,930	(49,401)	1,742,529
<b>2001, Restated (1)</b>			
Electricity and steam revenue .....	\$2,417,481	\$ 345,834	\$2,763,315
Sales of purchased power .....	3,332,412	(3,332,412)	—
Sales of purchased gas .....	526,517	(526,517)	—
Purchased power expense .....	2,986,578	(2,986,578)	—
Purchased gas expense .....	492,587	(492,587)	—
Fuel expense .....	1,170,977	(33,930)	1,137,047

	<u>GAAP Balance</u>	<u>To Net Hedging, Balancing &amp; Optimization Activity</u>	<u>Netted Non-GAAP Balance</u>
<b>2000, Restated (1)</b>			
Electricity and steam revenue.....	\$1,696,066	\$ 11,262	\$1,707,328
Sales of purchased power .....	369,911	(369,911)	—
Sales of purchased gas.....	87,119	(87,119)	—
Purchased power expense .....	358,649	(358,649)	—
Purchased gas expense .....	107,591	(107,591)	—
Fuel expense .....	602,165	20,472	622,637

(1) See Note 2 of Notes to Consolidated Financial Statements regarding the restatement of financial statements.

### Strategy

For a discussion of our strategy and management's outlook, see "Item 1 — Business — Strategy."

### Financial Market Risks

We primarily focused on generation of electricity using gas-fired turbines, our natural physical commodity position is "short" fuel (i.e., natural gas consumer) and "long" power (i.e., electricity seller). To manage forward exposure to price fluctuation in these and (to a lesser extent) other commodities, we enter into derivative commodity instruments as discussed in Item 6. "Business — Marketing, Hedging, Optimization and Trading Activities."

The change in fair value of outstanding commodity derivative instruments from January 1, 2002, through December 31, 2002, is summarized in the table below (in thousands):

Fair value of contracts outstanding at January 1, 2002 .....	\$ (88,123)
Gains recognized or otherwise settled during the period(1) .....	(210,745)
Changes in fair value attributable to changes in valuation techniques and assumptions(2) .....	(6,736)
Changes in fair value attributable to new contracts and price movements.....	218,421
Terminated derivatives(3) .....	<u>237,810</u>
Fair value of contracts outstanding at December 31, 2002(4) .....	<u>\$ 150,627</u>

(1) Recognized gains from commodity cash flow hedges of \$184.7 million, consisting of realized gains on power derivatives of \$304.1 million and realized losses on natural gas and crude oil derivatives of \$(119.4) million, are reported in Note 24 of the Consolidated Financial Statements and \$26.1 million realized gain on trading activity is reported in the Statement of Operations under trading revenue, net.

(2) Relates to liquidity reserves against unrealized mark-to-market gains to take into account recent illiquidity and the resulting increase in bid/ask spreads in the energy industry.

(3) Includes the value of derivatives terminated or settled before their scheduled maturity and the value of commodity financial instruments that ceased to qualify as derivative instruments.

(4) Net commodity derivative assets reported in Note 24 of the Notes to Consolidated Financial Statements included in this filing.

The fair value of outstanding derivative commodity instruments at December 31, 2002, based on price source and the period during which the instruments will mature, are summarized in the table below (in thousands):

<u>Fair Value Source</u>	<u>2003</u>	<u>2004-2005</u>	<u>2006-2007</u>	<u>After 2007</u>	<u>Total</u>
Prices actively quoted . . . . .	\$162,310	\$(9,236)	\$ —	\$ —	\$153,074
Prices provided by other external sources . . . . .	(6,325)	16,141	14,416	—	24,232
Prices based on models and other valuation methods . . . . .	<u>2,936</u>	<u>(6,178)</u>	<u>(17,334)</u>	<u>(6,103)</u>	<u>(26,679)</u>
Total fair value . . . . .	<u>\$158,921</u>	<u>\$ 727</u>	<u>\$(2,918)</u>	<u>\$(6,103)</u>	<u>\$150,627</u>

Our risk managers maintain fair value price information derived from various sources in our risk management systems. The propriety of that information is validated by our Risk Control group. Prices actively quoted include validation with prices sourced from commodities exchanges (e.g., New York Mercantile Exchange). Prices provided by other external sources include quotes from commodity brokers and electronic trading platforms. Prices based on models and other valuation methods are validated using quantitative methods. See Critical Accounting Policies for a discussion of valuation estimates used where external prices are unavailable.

The counterparty credit quality associated with the fair value of outstanding derivative commodity instruments at December 31, 2002, and the period during which the instruments will mature are summarized in the table below (in thousands):

<u>Credit Quality (based on January 23, 2003, ratings)</u>	<u>2003</u>	<u>2004-2005</u>	<u>2006-2007</u>	<u>After 2007</u>	<u>Total</u>
Investment grade . . . . .	\$114,931	\$11,641	\$ 8,361	\$(11,562)	\$123,371
Non-investment grade . . . . .	50,766	(9,260)	(10,982)	5,459	35,983
No external ratings . . . . .	<u>(6,776)</u>	<u>(1,654)</u>	<u>(297)</u>	<u>—</u>	<u>(8,727)</u>
Total fair value . . . . .	<u>\$158,921</u>	<u>\$ 727</u>	<u>\$(2,918)</u>	<u>\$(6,103)</u>	<u>\$150,627</u>

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

	<u>Fair Value</u>	<u>Fair Value After 10% Adverse Price Change</u>
At December 31, 2002:		
Crude oil . . . . .	\$ (2,274)	\$ (4,535)
Electricity . . . . .	47,745	(44,560)
Natural gas . . . . .	<u>105,156</u>	<u>(21,170)</u>
Total . . . . .	<u>\$150,627</u>	<u>\$(70,265)</u>

Derivative commodity instruments included in the table are those included in Note 24 to the Consolidated Financial Statements. The fair value of derivative commodity instruments included in the table is based on present value adjusted quoted market prices of comparable contracts. The fair value of electricity derivative commodity instruments after a 10% adverse price change includes the effect of increased power prices versus our derivative forward commitments. Conversely, the fair value of the natural gas derivatives after a 10% adverse price change reflects a general decline in gas prices versus our derivative forward commitments. Derivative commodity instruments offset the price risk exposure of our physical assets. None of the offsetting physical positions are included in the table above.

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 prices, the fair value of our derivative portfolio would typically change by more than ten percent for earlier forward months and less than ten percent for later forward months because of the higher volatilities in the near term and the effects of discounting expected future cash flows.

The primary factors affecting the fair value of our derivatives at any point in time are (1) the volume of open derivative positions (MMBtu and MWh), and (2) changing commodity market prices, principally for electricity and natural gas. The total volume of open gas derivative positions decreased 72% from December 31, 2001, to December 31, 2002, while the total volume of open power derivative positions decreased 15% for the same period. In that prices for electricity and natural gas are among the most volatile of all commodity prices, there may be material changes in the fair value of our derivatives over time, driven both by price volatility and the changes in volume of open derivative transactions. Under SFAS No. 133, the change since the last balance sheet date in the total value of the derivatives (both assets and liabilities) is reflected either in Other Comprehensive Income (“OCI”), net of tax, or in the statement of operations as an item (gain or loss) of current earnings. As of December 31, 2002, the majority of the balance in accumulated OCI represented the unrealized net loss associated with commodity cash flow hedging transactions. As noted above, there is a substantial amount of volatility inherent in accounting for the fair value of these derivatives, and our results during the year ended December 31, 2002, have reflected this. See Note 24 for additional information on derivative activity.

*Collateral Debt Securities* — The King City operating lease commitment is supported by collateral debt securities that mature serially in amounts equal to a portion of the semi-annual lease payment. We have the ability and intent to hold these securities to maturity, and as a result, we do not expect a sudden change in market interest rates to have a material affect on the value of the securities at the maturity date. The securities are recorded at an amortized cost of \$86.1 million at December 31, 2002. See Note 4 to the Consolidated Financial Statements. The following tables present our different classes of collateral debt securities by expected maturity date and fair market value as of December 31, 2002, (dollars in thousands):

	Weighted Average Interest Rate	2003	2004	2005	2006	2007	Thereafter	Total
Corporate Debt Securities . . . . .	7.2%	\$2,015	\$6,050	\$7,825	\$ —	\$ —	\$ —	\$ 15,890
Government Agency Debt Securities . . . . .	6.9%	1,960	—	—	—	—	—	1,960
U.S. Treasury Notes . . . . .	6.5%	—	—	1,975	—	—	—	1,975
U.S. Treasury Securities (non- interest bearing) . . . . .	—	4,065	—	—	9,700	9,100	96,150	119,015
Total . . . . .		<u>\$8,040</u>	<u>\$6,050</u>	<u>\$9,800</u>	<u>\$9,700</u>	<u>\$9,100</u>	<u>\$96,150</u>	<u>\$138,840</u>

	Fair Market Value
Corporate Debt Securities . . . . .	\$ 16,957
Government Agency Debt Securities . . . . .	1,968
U.S. Treasury Notes . . . . .	2,209
U.S. Treasury Securities (non-interest bearing) . . . . .	<u>83,333</u>
Total . . . . .	<u>\$104,467</u>

*Interest rate swaps and cross currency swaps* — From time to time, we use interest rate swap and cross currency swap agreements to mitigate our exposure to interest rate and currency fluctuations associated with certain of our debt instruments. We do not use interest rate swap and currency swap agreements for speculative or trading purposes. In regards to foreign currency denominated senior notes, the swap notional amounts equal the amount of the related principal debt. The following tables summarize the fair market

values of our existing interest rate swap and currency swap agreements as of December 31, 2002, (dollars in thousands):

<u>Maturity Date</u>	<u>Weighted Average Notional Principal Amount</u>	<u>Weighted Average Interest Rate (Pay)</u>	<u>Interest Rate (Receive)</u>	<u>Fair Market Value</u>
2008 .....	\$ 84,243	4.2%	(1)	\$ (5,294)
2011 .....	47,663	6.9%	3-month US \$ LIBOR	(7,748)
2012 .....	115,668	6.5%	3-month US \$ LIBOR	(19,484)
2014 .....	<u>64,319</u>	6.7%	3-month US \$ LIBOR	<u>(10,357)</u>
Total .....	<u>\$311,893</u>	6.0%		<u>\$ (42,883)</u>

(1) 1-month US \$ LIBOR until July, 2003. 3-month US \$ LIBOR thereafter.

<u>Maturity Date</u>	<u>Notional Principal (Pay/Receive)</u>	<u>Fixed Currency Exchange (Pay/Receive)</u>	<u>Frequency of Fixed Currency Exchange</u>	<u>Fair Market Value</u>
2007 ....	US \$127,763/ Cdn \$200,000	US \$5,545/ Cdn \$8,750	Semi-annually	\$ (7,714)
2008 ....	Pound sterling 109,550/ Euro 175,000	Pound sterling 5,152/ Euro 7,328	Semi-annually	8,486
Total ..				<u>\$ 772</u>

*Debt financing* — Because of the significant capital requirements within our industry, debt financing is often needed to fund our growth. Certain debt instruments may effect us adversely because of changes in market conditions. We have used two primary forms of debt which are subject to market risk: (1) Variable rate construction/project financing; (2) Other variable-rate instruments. Significant LIBOR increases could have a negative impact on our future interest expense. Our variable-rate construction/project financing is primarily through two separate credit agreements, Calpine Construction Finance Company L.P. and Calpine Construction Finance Company II, LLC. Borrowings under these credit agreements are used exclusively to fund the construction of our power plants. Other variable-rate instruments consist primarily of our revolving credit and term loan facilities which are used for general corporate purposes. Both our variable-rate construction/project financing and other variable-rate instruments are indexed to different LIBOR rates.

The following table summarizes our variable-rate debt exposed to interest rate risk as of December 31, 2002 (dollars in thousands):

	<u>Outstanding Balance</u>	<u>Weighted Average Interest Rate</u>	<u>Fair Market Value</u>
Variable-rate construction/project financing and other variable-rate instruments:			
Short-term			
Calpine Construction Finance Company L.P (due 2003) .....	\$ 970,110	1-month US \$ LIBOR	\$ 970,110
Corporate revolving line of credit .....	340,000	1-month US LIBOR	340,000
Siemens Westinghouse Power Corporation .....	169,180	6-month US \$ LIBOR	169,180
Total short-term .....	<u>\$1,479,290</u>		<u>\$1,479,290</u>
Long-term			
Blue Spruce Energy Center Project financing .....	\$ 83,540	1-month US \$ LIBOR	\$ 83,540
Term loan due (due 2004) .....	949,565	3-month US \$ LIBOR	949,565
Calpine Construction Finance Company II, LLC (due 2004) .....	<u>2,469,643</u>	1-month US \$ LIBOR	<u>2,469,643</u>
Total long-term .....	<u>\$3,502,748</u>		<u>\$3,502,748</u>
Total variable-rate construction/project financing and other variable-rate instruments .....	<u>\$4,982,038</u>		<u>\$4,982,038</u>

*Construction/project financing facilities* — In November 2003 and November 2004, respectively, our \$1.0 billion and \$2.5 billion, secured construction financing revolving facilities will mature, requiring us to refinance or extend this indebtedness. We remain confident that we will have the ability to refinance or extend this indebtedness as it matures, but recognize that this is dependent, in part, on market conditions that are difficult to predict.

*Revolving credit and term loan facilities* — On May 31, 2002, we increased our two-year secured bank term loan to \$1.0 billion from \$600.0 million, and reduced the aggregate size of our secured corporate revolving credit facilities to \$1.0 billion (the \$600 million and \$400 million facilities, respectively,) from \$1.4 billion. In the fourth quarter of 2002 we permanently repaid \$50.4 million of the term loan and at December 31, 2002, we had \$949.6 million in funded borrowings outstanding under the term loan, which matures in May 2004. Additionally we had \$340.0 million in funded borrowings outstanding and \$573.9 million in outstanding letters of credit under the revolving credit facilities, of which \$186.2 million of the letters of credit were issued in support of financial arrangements either reflected on the balance sheet or associated with leased assets or obligations of partially-owned subsidiaries. The revolving credit facilities expire in May 2003. However, any letters of credit under the \$600 million revolving credit facility can be extended for one year at our option.

#### **Application of Critical Accounting Policies**

Our financial statements reflect the selection and application of accounting policies which require management to make significant estimates and judgments. See Note 3 to our Consolidated Financial Statements, "Summary of Significant Accounting Policies." We believe that the following reflect the more critical accounting policies that currently affect our financial condition and results of operations.

#### ***Fair Value of Energy Marketing and Risk Management Contracts and Derivatives***

Generally Accepted Accounting Principles require us to account for certain derivative contracts at fair value. Accounting for derivatives at fair value requires us to make estimates about future prices during periods for which price quotes are not available from sources external to us. As a result, we are required to rely on internally developed price estimates when external price quotes are unavailable. Our estimates regarding future prices involve a level of uncertainty, and prices actually realized in the future could differ from our estimates.

We derive our future price estimates during periods where external price quotes are unavailable based on an extrapolation of prices from periods where external price quotes are available. In performing this extrapolation we estimate future annual prices and adjust them for observed monthly seasonality. We have quantified a range of likely one-year variability in our estimate by placing an upper bound and lower bound around our estimated future prices. We based our calculation of the likely upper and lower bounds on historically observed actual price trends and a five percent likelihood that actual future prices would be outside the calculated upper or lower bounds within one year. As of December 31, 2002, we estimate the fair value of our commodity derivative instruments to be \$150.6 million. If we were to adjust our estimated prices during periods where external price quotes are unavailable to the upper bound and lower bound, the fair value of our commodity derivative instruments would be \$198.2 million and \$146.1 million, respectively.

#### *Credit Reserves*

In estimating the fair value of our derivatives, we must take into account the credit risk that our counterparties will not have the financial wherewithal to honor their contract commitments.

In establishing credit risk reserves we take into account historical default rate data published by the rating agencies based on the credit rating of each counterparty where we have realization exposure, as well as other published data and information.

#### *Liquidity Reserves*

We value our forward positions at the mid-market price, or the price in the middle of the bid-ask spread. This creates a risk that the value reported by us as the fair value of our derivative positions will not represent the realizable value or probable loss exposure of our derivative positions if we are unable to liquidate those positions at the mid-market price. Adjusting for this liquidity risk states our derivative assets and liabilities at their most probable value. We use a two-step quantitative and qualitative analysis to determine our liquidity reserve.

In the first step we quantitatively derive an initial liquidity reserve assessment applying the following assumptions in calculating the initial liquidity reserve assessment: (1) where we have the capability to cover physical positions with our own assets, we assume no liquidity reserve is necessary because we will not have to cross the bid ask spread in covering the position; (2) we record no reserve against our hedge positions because a high likelihood exists that we will hold our hedge positions to maturity or cover them with our own assets; and (3) where reserves are necessary, we base the reserves on the spreads observed using broker quotes as a starting point.

Using these assumptions, we calculate the net notional volume exposure at each location by commodity and multiply the result by one half of the bid-ask spread.

The second step involves a qualitative analysis where the initial assessment may be adjusted for qualitative factors such as liquidity spreads observed through recent trading activity, strategies for liquidating open positions, and imprecision in or unavailability of broker quotes due to market illiquidity. Using this quantitative and qualitative information, we estimate the amount of probable liquidity risk exposure to us and we record this estimate as a liquidity reserve.

#### *Accounting for Long-Lived Assets*

##### *Plant Useful Lives*

Property, plant and equipment is stated at cost. The cost of renewals and betterments that extend the useful life of property, plant and equipment are also capitalized. Depreciation is recorded utilizing the straight-line method over the estimated original composite useful life, generally 35 years, exclusive of the estimated salvage value, typically 10%.

### *Impairment of Long-Lived Assets, Including Intangibles*

We evaluate long-lived assets, such as property, plant and equipment, equity method investments, patents, and specifically identifiable intangibles, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. Factors which could trigger an impairment include significant underperformance relative to historical or projected future operating results; significant changes in the manner of our use of the acquired assets or the strategy for our overall business; and significant negative industry or economic trends.

The determination of whether an impairment has occurred is based on an estimate of undiscounted cash flows attributable to the assets, as compared to the carrying value of the assets. If an impairment has occurred, the amount of the impairment loss recognized would be determined by estimating the fair value of the assets and recording a loss if the fair value was less than the book value. For equity method investments and assets identified as held for sale, the book value is compared to the estimated fair value to determine if an impairment loss is required. For equity method investments, we would record a loss when the decline in value is other than temporary.

Our assessment regarding the existence of impairment factors is based on market conditions, operational performance and legal factors of our businesses. Our review of factors present and the resulting appropriate carrying value of our intangibles, and other long-lived assets are subject to judgments and estimates that management is required to make. Future events could cause us to conclude that impairment indicators exist and that our intangibles, and other long-lived assets might be impaired.

### *Turbine Impairment Charges*

A significant portion of our overall cost of constructing a power plant is the cost of the gas turbine-generators (GTGs), steam turbine-generators (STGs) and related equipment (collectively the “turbines”). The turbines are ordered primarily from three large manufacturers under long-term, build to order contracts. Payments are generally made over a two to four year period for each turbine. The turbine prepayments are included as a component of construction-in-progress if the turbines are assigned to specific projects probable of being built, and interest is capitalized on such costs. Turbines assigned to specific projects are not evaluated for impairment separately from the project as a whole. Prepayments for turbines that are not assigned to specific projects that are probable of being built are carried in other assets, and interest is not capitalized on such costs. Additionally, our commitments relating to future turbine payments are disclosed in Note 26, “Commitments and Contingencies.”

At each reporting date, we assess the total balance of turbine progress payments made to date to determine whether there has been any impairment in the value of the prepayments. This assessment is based on the relationship between the turbines on order, their allocation to respective construction and development projects and the probability that these projects will be completed. Additionally, to the extent that there are more turbines on order than are allocated to specific construction projects, we must also determine the probability that new projects will be initiated to utilize the turbines or that the turbines will be resold to third parties. The completion of in progress projects and the initiation of new projects are dependent on our overall liquidity and the availability of funds for capital expenditures.

In assessing the impairment of turbines, we must determine both the realizability of the progress payments to date that have been capitalized, as well as the probability that at future decision dates, we will cancel the turbines, forfeiting the prepayment and incurring the cancellation payment, or will proceed and pay the remaining progress payments in accordance with the original payment schedule.

We apply SFAS No. 5, “Accounting for Contingencies” to evaluate potential future cancellation obligations. We apply SFAS No. 144, “Accounting for the Impairment or Disposal of Long-Lived Assets” to evaluate turbine progress payments made to date and the carrying value of delivered turbines not assigned to projects. At the reporting date, if we do not believe that it is probable that the development or construction project associated with each turbine will be financed within the timeframe in which decisions about whether we will need the turbine or not must be made, then the progress payments (reservation payments) made to

date are written off. Additionally, if we believe that it is probable that we will elect the cancellation provisions relating to future decision dates, then the expected future termination payment is also expensed.

#### *Oil and Gas Property Valuations*

*Successful Efforts Method of Accounting.* We follow the successful efforts method of accounting for oil and natural gas activities. Under the successful efforts method, lease acquisition costs and all development costs are capitalized. Exploratory drilling costs are capitalized until the results are determined. If proved reserves are not discovered, the exploratory drilling costs are expensed. Other exploratory costs are expensed as incurred. Interest costs related to financing major oil and gas projects in progress are capitalized until the projects are evaluated, or until the projects are substantially complete and ready for their intended use if the projects are evaluated as successful.

The successful efforts method of accounting relies on management's judgment in the designation of wells as either exploratory or developmental, which determines the proper accounting treatment of costs incurred. During 2002, we drilled 140 (net 82.3) development wells and 8 (net 4.9) exploratory wells, of which 128 (net 75.3) development and one (net 0.5) exploration were successful. Our operational results may be significantly impacted if we decide to drill in a new exploratory area, which will result in increased seismic costs and potentially increased dry hole costs if the wells are determined to be not successful.

*Successful Efforts Method of Accounting vs. Full Cost Method of Accounting.* Under the successful efforts method, unsuccessful exploration well cost, geological and geophysical costs, delay rentals, and general and administrative expenses directly allocable to acquisition, exploration, and development activities are charged to exploration expense as incurred; whereas, under the full cost method these costs are capitalized and amortized over the life of the reserves.

A significant sale would have to occur before a gain or loss would be recognized under the full cost method but, when an entire cost center (generally a field) is sold under successful efforts method, a gain or loss is recognized.

For impairment evaluation purposes, successful efforts requires that individual assets are grouped for impairment purposes at the lowest level for which there are identifiable cash flows, which are generally on a field-by-field basis. Under full cost impairment review, all properties in the depreciation, depletion and amortization pools are assessed against a ceiling based on discounted cash flows, with certain adjustments.

Though successful efforts and full cost methods are both acceptable under GAAP, historically successful efforts is used by most major companies due to such method being more reflective of current operating results due to expensing of certain exploration activities.

*Impairment of Oil and Gas Properties.* We review our oil and gas properties periodically to determine if impairment of such properties is necessary. Property impairments may occur if a field discovers lower than anticipated reserves or if commodity prices fall below a level that significantly affects anticipated future cash flows on the property. Proved oil and gas property values are reviewed when circumstances suggest the need for such a review and, if required, the proved properties are written down to their estimated fair value. Unproved properties are reviewed quarterly to determine if there has been impairment of the carrying value, with any such impairment charged to expense in the current period. During 2002, we recorded approximately \$6 million in property impairments.

*Oil and Gas Reserves.* 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. Estimates of economically recoverable oil and gas reserves and future net cash flows depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effect of governmental regulations, operating costs, severance taxes, development costs and workover costs, all of which may vary considerably from actual results. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of our oil and gas properties and/or the rate of depletion of such properties.

We base estimates of proved, proved developed, and proved undeveloped reserves as of December 31, 2002, on estimates made by Netherland, Sewell & Associates Inc., independent petroleum consultants, for reserves in the United States; and Gilbert Laustsen Jung Associates Ltd. independent petroleum consultants, for reserves in Canada.

### ***Capitalized Interest***

We capitalize interest using two methods: (1) capitalized interest on funds borrowed for specific construction projects and (2) capitalized interest on general corporate funds. For capitalization of interest on specific funds, we capitalize the interest cost incurred related to debt entered into for specific projects under construction or in the advanced stage of development. The methodology for capitalizing interest on general funds, consistent with paragraphs 13 and 14 of SFAS No. 34, "Capitalization of Interest Cost," begins with a determination of the borrowings applicable to our qualifying assets. The basis of this approach is the assumption that the portion of the interest costs that are capitalized on expenditures during an asset's acquisition period could have been avoided if the expenditures had not been made. This methodology takes the view that if funds are not required for construction then they would have been used to pay off other debt. We use our best judgment in determining which borrowings represent the cost of financing the acquisition of the assets. The primary debt instruments included in the rate calculation are the Senior Notes, our term loan facility and the \$600.0 million and the \$400.0 million revolving credit facilities. The interest rate is derived by dividing the total interest cost by the average borrowings. This weighted average interest rate is applied to our average qualifying assets. See Note 5 to the Consolidated Financial Statements, for additional information about the capitalization of interest expense.

### ***Accounting for Income Taxes***

To arrive at our worldwide income tax provision significant judgment is required. In the ordinary course of a global business, there are many transactions and calculations where the ultimate tax outcome is uncertain. Some of these uncertainties arise as a consequence of the treatment of capital assets, financing transactions, multistate taxation of operations and segregation of foreign and domestic income and expense to avoid double taxation. Although we believe that our estimates are reasonable, no assurance can be given that the final tax outcome of these matters will not be different than that which is reflected in our historical income tax provisions and accruals. Such differences could have a material impact on our income tax provision and net income in the period in which such determination is made.

We record a valuation allowance to reduce our deferred tax assets to the amount of future tax benefit that is more likely than not to be realized. While we have considered future taxable income and ongoing prudent and feasible tax planning strategies in assessing the need for the valuation allowance, there is no assurance that the valuation allowance would not need to be increased to cover additional deferred tax assets that may not be realizable. Any increase in the valuation allowance could have a material adverse impact on our income tax provision and net income in the period in which such determination is made.

We provide for United States income taxes on the earnings of foreign subsidiaries unless they are considered permanently invested outside the United States. At December 31, 2002, we had no cumulative undistributed earnings of foreign subsidiaries.

Our effective income tax rates were (63.7)%, 33.7% and 41.0% in fiscal 2002, 2001 and 2000, respectively. The effective tax rate in all periods is the result of profits Calpine Corporation and its subsidiaries earned in various tax jurisdictions, both foreign and domestic, that apply a broad range of income tax rates. The provision for income taxes differs from the tax computed at the federal statutory income tax rate due primarily to state taxes and earnings considered as permanently reinvested in foreign operations and the effect of the treatment by foreign jurisdictions of cross border financings. Future effective tax rates could be adversely affected if earnings are lower than anticipated in countries where we have lower statutory rates, if unfavorable changes in tax laws and regulations occur, or if we experience future adverse determinations by taxing authorities after any related litigation. For calendar year 2002 the state tax rate increased over prior years due to a one-time adjustment increasing our deferred state taxes and receiving no benefit for foreign

losses in our state tax filings. Our foreign taxes at rates other than statutory include the benefit of cross border financings as well as withholding taxes and foreign valuation allowance.

Under SFAS No. 109, "Accounting for Income Taxes," deferred tax assets and liabilities are determined based on differences between the financial reporting and tax basis of assets and liabilities, and are measured using enacted tax rates and laws that will be in effect when the differences are expected to reverse. SFAS No. 109 provides for the recognition of deferred tax assets if realization of such assets is more likely than not. Based on the weight of available evidence, we have provided a valuation allowance against certain deferred tax assets. The valuation allowance was based on the historical earnings patterns within individual tax jurisdictions that make it uncertain that we will have sufficient income in the appropriate jurisdictions to realize the full value of the assets. We will continue to evaluate the realizability of the deferred tax assets on a quarterly basis.

At December 31, 2002, we had credit carryforwards, resulting in a \$34.4 million tax benefit, which originated from acceleration of deductions on capital assets. We expect to utilize all of the credit carryforwards. We also had federal and state net operating loss carryforwards of \$22.1 million, which expire between 2004 and 2014. The federal and state net operating loss carryforwards available are subject to limitations on annual usage. In addition, we had loss carryforwards in certain foreign subsidiaries, resulting in a tax benefit of approximately \$87.4 million, the majority of which expire by 2008. It is expected that they will be fully utilized before expiring. The deferred tax asset for the federal and state losses, foreign losses, and other prepaid taxes has been offset by a valuation allowance of approximately \$26.7 million.

### **Initial Adoption of New Accounting Standards in 2003**

#### ***SFAS No. 123 — "Accounting for Stock-Based Compensation" and SFAS No. 148 "Accounting for Stock-Based Compensation — Transition and Disclosure"***

Historically, we have accounted for qualified stock compensation under APB Opinion No. 25, "Accounting for Stock Issued to Employees" ("APB 25"). Under APB 25, we are required to recognize stock compensation as expense only to the extent that there is a difference in value between the market price of the stock being offered to employees and the price those employees must pay to acquire the stock. The expense measurement methodology provided by APB 25 is commonly referred to as the "intrinsic value based method". To date, our stock compensation program has been based primarily on stock options whose exercise prices are equal to the market price of Calpine stock on the date of the stock option grant; consequently, we have historically incurred minimal stock compensation expense. On August 27, 2002, we announced that, effective January 1, 2003, we intend to prospectively adopt SFAS No. 123, "Accounting for Stock-Based Compensation" ("SFAS No. 123"). SFAS No. 123 establishes the use of a "fair value based method" of accounting for stock-based compensation plans.

Under SFAS No. 123, the fair value of a stock option or its equivalent is estimated on the date of grant by using an option-pricing model, such as the Black-Scholes model or a binomial model. The option-pricing model selected should take into account, as of the stock option's grant date, the exercise price and expected life of the stock option, the current price of the underlying stock and its expected volatility, expected dividends on the stock, and the risk-free interest rate for the expected term of the stock option.

The fair value calculated by this model is then recognized as compensation expense over the period in which the related employee services are rendered. Unless specifically defined within the provisions of the stock option granted, the service period is presumed to begin on the grant date and end when the stock option is fully vested. Depending on the vesting structure of the stock option and other variables that are built into the option-pricing model, the fair value of the stock option is recognized over the service period using either a straight-line method (the single option approach) or a more conservative, accelerated method (the multiple option approach). Recognizing that employees are entitled to portions of a given stock option grant at different points throughout the vesting period, we have chosen the multiple option approach, which we have used historically for pro-forma disclosure purposes. The multiple option approach views one four-year option grant as four separate sub-grants, each representing 25% of the total number of stock options granted. The first sub-

grant vests over one year, the second sub-grant vests over two years, the third sub-grant vests over three years, and the fourth sub-grant vests over four years. Under this scenario, over 50% of the total fair value of the stock option grant is recognized during the first year of the vesting period, and nearly 80% of the total fair value of the stock option grant is recognized by the end of the second year of the vesting period. By contrast, if we were to apply the single option approach, only 25% and 50% of the total fair value of the stock option grant would be recognized as compensation expense by the end of the first and second years of the vesting period, respectively.

We have selected the Black-Scholes model, primarily because it is the most commonly recognized options-pricing model among U.S.-based corporations. Nonetheless, we believe this model tends to overstate the true fair value of our employee stock options in that our options cannot be freely traded, have vesting requirements, and are subject to blackout periods during which, even if vested, they cannot be traded. We will monitor valuation trends and techniques as more companies adopt SFAS No. 123 and review our choices as appropriate in the future. The key assumption in our Black-Scholes model is the expected life of the stock option, because it is this figure that drives our expected volatility calculation, as well as our risk-free interest rate. The expected life of the option relies on two factors — the option's vesting period and the expected term that an employee holds the option once it has vested. There is no single method described by SFAS No. 123 for predicting future events such as how long an employee holds on to an option or what the expected volatility of a company's stock price will be; the facts and circumstances are unique to different companies and depend on factors such as historical employee stock option exercise patterns, significant changes in the market place that could create a material impact on a company's stock price in the future, and changes in a company's stock-based compensation structure.

We will base our expected option terms on historical employee exercise patterns. We have segregated our employees into four different categories based on the fact that different groups of employees within our company have exhibited different stock exercise patterns in the past, usually based on employee rank and income levels. Therefore, we have concluded that we will perform separate Black-Scholes calculations for four employee groups — executive officers, senior vice presidents, vice presidents, and all other employees.

We will compute our expected stock price volatility based on our stock's historical movements. For each employee group, we will measure the volatility of our stock over a period that equals the expected term of the option. In the case of our executive officers, this means we will measure our stock price volatility dating back to our public inception in 1996, because these employees are expected to hold their options for over 7 years after the options have fully vested. In the case of other employees, volatility will only be measured dating back 4 years. In the short run, this will cause other employees to generate a higher volatility figure than the other company employee groups because our stock price has fluctuated significantly in the past four years. As of December 31, 2002, the volatility for our employee groups ranged from 70%-83%.

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation — Transition and Disclosure" ("SFAS No. 148"). SFAS No. 148 provides alternative methods of transition for companies that voluntarily change their accounting for stock-based compensation from the less preferred intrinsic value based method to the more preferred fair value based method. Prior to its amendment, SFAS No. 123 required that companies enacting a voluntary change in accounting principle from the APB 25 methodology could only do so on a prospective basis; no adoption or transition provisions were established to allow for a restatement of prior period financial statements. Companies adopting SFAS No. 123 were required to provide a pro-forma disclosure of net income and earnings per share as if the fair value based method had been used to account for their stock-based compensation for all periods presented within their financial statements. SFAS No. 148 provides two additional transition options to report the change in accounting principle — the modified prospective method and the retroactive restatement method. We will use the prospective method in our implementation of SFAS No. 123.

Based on our Black-Scholes assumptions described above, and based on our SIP grant that occurred in January 2003, we anticipate that adopting the provisions of SFAS No. 123 and SFAS No. 148 will result in a pre-tax charge of \$18.1 million to compensation expense during 2003. See Note 3 to the Consolidated

Financial Statements for additional information related to the adoption of SFAS No. 148 and the pro-forma impact that it would have had on our net income for the years ended December 31, 2002, 2001 and 2000.

***SFAS 143 — “Accounting for Asset Retirement Obligations”***

In June 2001, the FASB issued SFAS No. 143 “Accounting for Asset Retirement Obligations”. SFAS No. 143 applies to fiscal years beginning after June 15, 2002 and amends SFAS No. 19, “Financial Accounting and Reporting by Oil and Gas Producing Companies.” This standard applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development or normal use of the assets and requires that a liability for an asset retirement obligation be recognized when incurred, recorded at fair value and classified as a liability in the balance sheet. When the liability is initially recorded, the entity will capitalize the cost and increase the carrying value of the related long-lived asset. Asset retirement obligations represent future liabilities, and, as a result, accretion expense will be accrued on this liability until the obligation is satisfied. At the same time, the capitalized cost will be depreciated over the estimated useful life of the related asset. At the settlement date, the entity will settle the obligation for its recorded amount or recognize a gain or loss upon settlement.

We adopted the new rules on asset retirement obligations on January 1, 2003. As required by the new rules, we recorded liabilities equal to the present value of expected future asset retirement obligations at January 1, 2003. We identified obligations related to operating gas-fired power plants, geothermal power plants and oil and gas properties. The liabilities are partially offset by increases in net assets, net of accumulated depreciation, recorded as if the provisions of the Statement had been in effect at the date the obligation was incurred, which is generally the start of commercial operations for the facility.

Based on current information and assumptions we expect to record an additional long-term liability of \$33.3 million, an additional asset within Property, Plant and Equipment, net of accumulated depreciation, of \$33.7 million, and a gain to income due to the cumulative effect of a change in accounting principle of (\$0.4) million, net of taxes which entries includes the reversal of site dismantlement and restoration costs previously expensed in accordance with SFAS No. 19. Due to the complexity of this accounting standard, and the number of assumptions used in the calculations, we may make adjustments to these estimates prior to the filing of Form 10-Q for the quarter ending March 31, 2003.

***FIN 45 — “Guarantors Accounting and Disclosure for Guarantees, Including Indirect Guarantees of Indebtedness of Others”***

In November 2002 the FASB issued Interpretation No. 45, “Guarantor’s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others” (“FIN 45”). FIN 45 elaborates on the existing disclosure requirements for most guarantees. FIN 45 also clarifies that at the time a company issues a guarantee, it must recognize an initial liability for the fair value of the obligation it assumes under that guarantee, including its ongoing obligation to stand ready to perform over the term of the guarantee in the event that specified triggering events or conditions occur. The initial recognition and initial measurement provisions apply on a prospective basis to guarantees issued or modified after December 31, 2002. We are currently evaluating the impact of FIN 45’s initial recognition and measurement provisions on our Consolidated Financial Statements. The disclosure requirements for FIN 45 are effective for financial statements of interim or annual periods ending after December 15, 2002, and have been incorporated into our December 31, 2002, disclosures of guarantees in the Notes to Consolidated Financial Statements. See “Commercial Commitments” in the Liquidity and Capital Resources section and Note 26 Commitments and Contingencies for the disclosures.

## **Impact of Recent Accounting Pronouncements**

### **SFAS 133 — “Accounting for Derivative Instruments and Hedging Activities”**

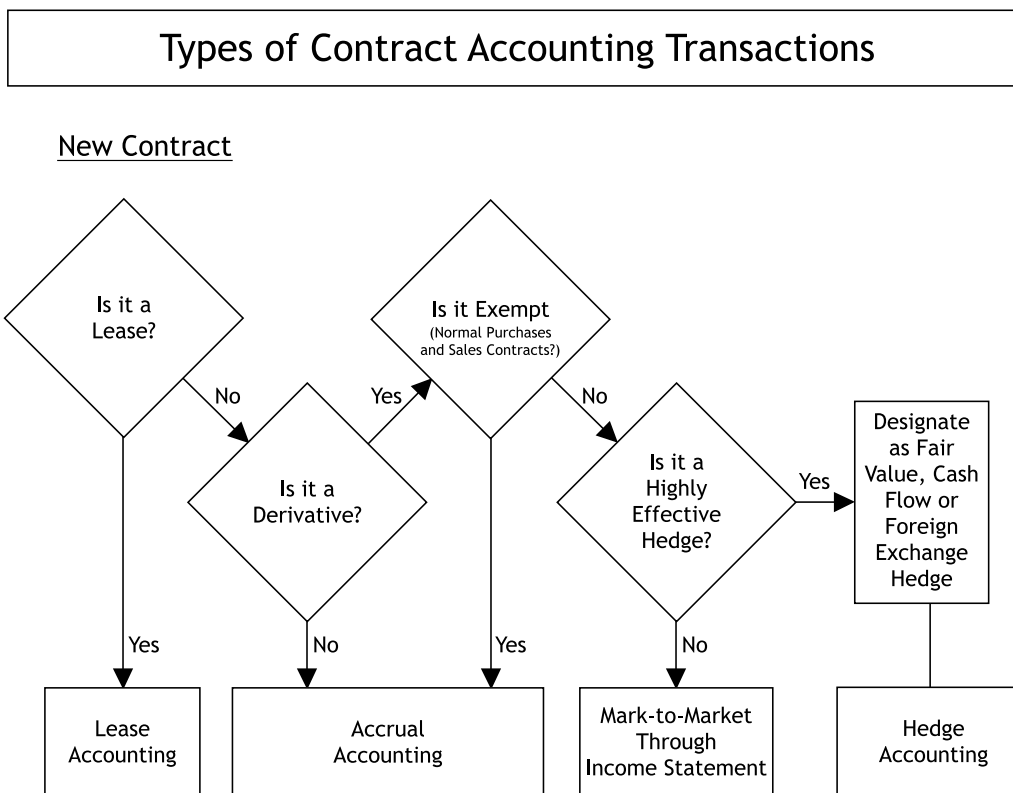
FASB in recent years has issued numerous new accounting standards that have already taken effect or will soon impact us. In Note 3 to our Consolidated Financial Statements, we invite your attention to a discussion of ten new standards, emerging issues and interpretations under the section entitled “New Accounting Pronouncements.”

Below is a detailed discussion of how we apply SFAS No. 133 since this accounting standard has a profound impact on how we account for our energy contracts and transactions.

On January 1, 2001, we adopted SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities,” as amended by 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,” and SFAS No. 138, “Accounting for Certain Derivative Instruments and Certain Hedging Activities — an Amendment of FASB Statement No. 133.” We currently hold six classes of derivative instruments that are impacted by the new pronouncement — foreign currency swaps, interest rate swaps, forward interest rate agreements, commodity financial instruments, commodity contracts, and physical options.

Consistent with the requirements of SFAS No. 133, we evaluate all of our contracts to determine whether or not they qualify as derivatives under the accounting pronouncement. For a given contract, there are typically three steps we use to determine its proper accounting treatment. First, based on the terms and conditions of the contract, as well as the applicable guidelines established by SFAS No. 133, we identify the contract as being either a derivative or non-derivative contract. Second, if the contract is not a derivative, we further identify its specific classification (e.g. whether or not it qualifies as a lease) and apply the appropriate non-derivative accounting treatment. Alternatively, if the contract does qualify as a derivative under the guidance of SFAS No. 133, we evaluate whether or not it qualifies for the “normal” purchases and sales exception (as described below). If the contract qualifies for the exception, we apply the traditional accrual accounting treatment. Finally, if the contract qualifies as a derivative and does not qualify for the “normal” purchases and sales exception, we apply the accounting treatment required by SFAS No. 133, which is

outlined below in further detail. The diagram below illustrates the process we use for the purposes of identifying the classification and subsequent accounting treatment of our contracts:



Classification Flow Chart

As an independent power producer primarily focused on generation of electricity using gas-fired turbines, our natural physical commodity position is “short” fuel (i.e., natural gas consumer) and “long” power capacity (i.e., electricity seller). Additionally, we also have a natural “long” crude position due to our petroleum reserves. To manage forward exposure to price fluctuation, we execute commodity derivative contracts as defined by SFAS No. 133. As we apply SFAS No. 133, derivatives can receive one of four treatments depending on associated circumstances: 1. exemption from SFAS No. 133 accounting treatment if these contracts qualify as “normal” purchases and sales contracts; 2. fair value hedges; 3. cash flow hedges; or 4. undesignated derivatives.

*Normal purchases and sales*

Normal purchases and sales, as defined by paragraph 10b. of SFAS No. 133 and amended by SFAS No. 138, are exempt from SFAS No. 133 accounting treatment. As a result, these contracts are not required to be recorded on the balance sheet at their fair values and any fluctuations in these values are not required to be reported within earnings. Probability of physical delivery from our generation plants, in the case of electricity sales, and to our generation plants, in the case of natural gas contracts, is required over the life of the contract within reasonable tolerances.

On June 27, 2001, the FASB cleared SFAS No. 133 Implementation Issue No. C15 dealing with a proposed electric industry normal purchases and sales exception for capacity sales transactions (“The Eligibility of Option Contracts in Electricity for the Normal Purchases and Normal Sales Exception”). On December 19, 2001, the FASB revised the criteria for qualifying for the “normal” exception. As a result of

Issue No. C15, as revised, certain power purchase and/or sale agreements that are structured as capacity sales contracts are now eligible to qualify for the normal purchases and sales exception. Because we are “long” power capacity, we often enter into capacity sales contracts as a means to recover the costs incurred from maintaining and operating our power plants as well as the costs directly associated with the generation and sale of electricity to our customers. Under Issue No. C15, a capacity sales contract qualifies for the normal purchases and sales exception subject to certain conditions.

A majority of our capacity sales contracts qualify for the normal purchases and sales exception.

#### *Cash flow hedges and fair value hedges*

Within the energy industry, cash flow and fair value hedge transactions typically use the same types of standard transactions (i.e., *offered* for purchase/sale in over-the-counter markets or commodity exchanges).

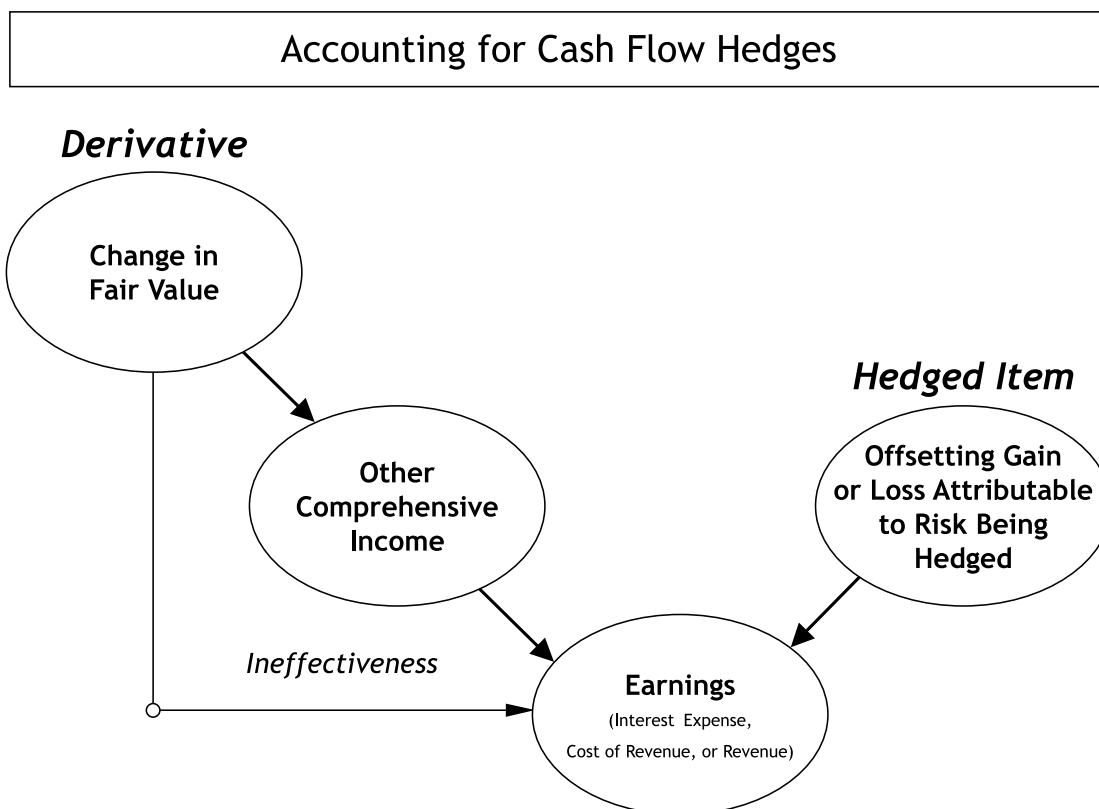
#### *Fair Value Hedges*

As further defined in SFAS No. 133, fair value hedge transactions hedge the exposure to changes in the fair value of either all or a specific portion of a recognized asset or liability or of an unrecognized firm commitment. The accounting treatment for fair value hedges requires reporting both the changes in fair values of a *hedged* item (the underlying risk) and the *hedging* instrument (the derivative designated to offset the underlying risk) on both the balance sheet and the income statement. On that basis, when a firm commitment is associated with a hedge instrument that attains 100% effectiveness (under the effectiveness criteria outlined in SFAS No. 133), there is no net earnings impact because the earnings caused by the changes in fair value of the hedged item will move in an equal, but opposite, amount as the earnings caused by the changes in fair value of the hedging instrument. In other words, the earnings volatility caused by the underlying risk factor will be neutralized because of the hedge. For example, if we want to manage the price risk (i.e. the risk that market electric rates will rise, making a fixed price contract less valuable) associated with all or a portion of a fixed price power sale that has been identified as a “normal” transaction (as described above), we might create a fair value hedge by purchasing fixed price power. From that date and time forward until delivery, the change in fair value of the hedged item and hedge instrument will be reported in earnings with asset/liability offsets on the balance sheet. If there is 100% effectiveness, there is no net earnings impact. If there is less than 100% effectiveness, the fair value change of the hedged item (the underlying risk) and the hedging instrument (the derivative) will likely be different and the “ineffectiveness” will result in a net earnings impact.

#### *Cash Flow Hedges*

As further defined in SFAS No. 133, cash flow hedge transactions hedge the exposure to variability in expected future cash flows (i.e., in our case, the price variability of forecasted purchases of gas and sales of power, as well as interest rate and foreign exchange rate exposure). In the case of cash flow hedges, the hedged item (the underlying risk) is generally unrecognized (i.e., not recorded on the balance sheet prior to delivery), and any changes in this fair value, therefore, will not be recorded within earnings. Conceptually, if a cash flow hedge is effective, this means that a variable, such as movement in power prices, has been effectively fixed, so that any fluctuations will have no net result on either cash flows or earnings. Therefore, if the changes in fair value of the hedged item are not recorded in earnings, then the changes in fair value of the hedging instrument (the derivative) must also be excluded from the income statement, or else a one-sided net impact on earnings will be reported, despite the fact that the establishment of the effective hedge results in no net economic impact. To prevent such a scenario from occurring, SFAS No. 133 requires that the fair value of a derivative instrument designated as a cash flow hedge be recorded as an asset or liability on the balance sheet, but with the offset reported as part of other comprehensive income (“OCI”), to the extent that the hedge is

effective. Similar to fair value hedges, any ineffectiveness portion will be reflected in earnings. The diagram below illustrates the process used to account for derivatives designated as cash flow hedges:



Certain contracts could either qualify for exemption from SFAS No. 133 accounting as normal purchases or sales or be designated as effective hedges. Our marketing and fuels groups generally transact with load serving entities and other end-users of electricity and with fuel suppliers, respectively, in physical contracts where delivery is expected. These transactions are structured as normal purchases and sales, when possible and, if the normal exception is not allowed, we seek to structure the transactions as cash flow hedges. Conversely, our CES risk management desks generally transact in over-the-counter or exchange traded contracts, in hedging transactions. These transactions are designated as hedges when possible, notwithstanding the fact that some might qualify as normal purchases or sales.

#### *Undesignated derivatives*

The fair values and changes in fair values of undesignated derivatives are recorded in earnings, with the corresponding offsets recorded as derivative assets or liabilities on the balance sheet. We have the following types of undesignated transactions:

- transactions are executed at a location where we do not have an associated natural long (generation capacity) or short (fuel consumption requirements) position of sufficient quantity for the entire term of the transaction (e.g., power sales where we do not own generating assets or intend to acquire transmission rights for delivery from other assets for a portion of the contract term), and
- transactions executed with the intent to profit from short-term price movements
- Discontinuance (de-designation) of hedge treatment prospectively consistent with paragraphs 25 and 32 of SFAS No. 133. In circumstances where we believe the hedge relationship is no longer

necessary, we will remove the hedge designation and close out the hedge positions by entering into an equal and offsetting derivative position. Prospectively, the two derivative positions should generally have no net earnings impact because the changes in their fair values are offsetting.

*Accumulated Other Comprehensive Income*

Accumulated other comprehensive income (“AOCI”) includes the following components: (i) unrealized pre-tax gains/losses, net of reclassification-to-earnings adjustments, from effective cash flow hedges as designated pursuant to SFAS No. 133, (see Note 24 to the Consolidated Financial Statements); (ii) unrealized pre-tax gains/losses that result from the translation of foreign subsidiaries’ balance sheets from the foreign functional currency to our consolidated reporting currency (US \$); (iii) other comprehensive income from equity method investees; and (iv) the taxes associated with the unrealized gains/losses from items (i), (ii) and (iii). See Note 22 to the Consolidated Financial Statements for further information.

One result of our adoption on January 1, 2001, of SFAS No. 133 has been volatility in the AOCI component of Stockholders’ Equity on the balance sheet. As explained in Notes 22 and 24 to our Consolidated Financial Statements, our AOCI balances are primarily related to our cash flow hedging activity. The quarterly balances for 2002 in AOCI related to cash flow hedging activity are summarized in the table below (in thousands).

	Quarter Ended			
	December 31	September 30	June 30	March 31
AOCI balances related to cash flow hedging . . . . .	\$(224,414)	\$(202,326)	\$(123,198)	\$(132,845)

Note that the amounts above represent AOCI from cash flow hedging activity only. For further information on other components of our total AOCI balance at December 31, 2002, see Note 22.

**Item 7A. Quantitative and Qualitative Disclosure About Market Risk**

The information required hereunder is set forth under “Management’s Discussion and Analysis of Financial Condition and Results of Operation — Financial Market Risks.”

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

The information required hereunder is set forth under “Independent Auditors’ Report,” “Report of Independent Chartered Accountants,” “Consolidated Balance Sheets,” “Consolidated Statements of Operations,” “Consolidated Statements of Stockholders’ Equity,” “Consolidated Statements of Cash Flows,” and “Notes to Consolidated Financial Statements” included in the Consolidated Financial Statements that are a part of this report. Other financial information and schedules are included in the Consolidated Financial Statements that are a part of this report.

**Item 9. Changes in and Disagreements With Accountants on Accounting and Financial Disclosure**

None.

**PART III**

**Item 10. Directors and Executive Officers of the Registrant**

Incorporated by reference to Proxy Statement relating to the 2003 Annual Meeting of Stockholders to be filed.

**Item 11. Executive Compensation**

Incorporated by reference to Proxy Statement relating to the 2003 Annual Meeting of Stockholders to be filed.

**Item 12. *Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters***

Incorporated by reference to Proxy Statement relating to the 2003 Annual Meeting of Stockholders to be filed.

**Item 13. *Certain Relationships and Related Transactions***

Incorporated by reference to Proxy Statement relating to the 2003 Annual Meeting of Stockholders to be filed.

**Item 14. *Controls and Procedures***

An evaluation was performed under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-14(c) and 15d-14(c) under the Securities Exchange Act). In designing and evaluating the disclosure controls and procedures, our management, including our Chief Executive Officer and Chief Financial Officer, recognized that any controls and procedures, no matter how well designed and operated, can provide only reasonable assurance of achieving the desired control objectives and management necessarily was required to apply its judgment in evaluating the cost-benefit relationship of possible controls and procedures. Based on that evaluation, which was completed within 90 days of the filing of this report, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures provided reasonable assurance of effectiveness at that time. Since that time, there have been no significant changes in our internal controls or in other factors that could significantly affect these controls.

**PART IV**

**Item 15. *Exhibits, Financial Statement Schedules, and Reports on Form 8-K***

**(a)-1. Financial Statements and Other Information**

The following items appear in Appendix F of this report:

- Independent Auditors' Report
- Consolidated Balance Sheets, December 31, 2002 and 2001 (Restated)
- Consolidated Statements of Operations for the Years Ended December 31, 2002, 2001 (Restated), and 2000 (Restated)
- Consolidated Statements of Stockholders' Equity for the Years Ended December 31, 2002, 2001 (Restated), and 2000 (Restated)
- Consolidated Statements of Cash Flows for the Years Ended December 31, 2002, 2001 (Restated), and 2000 (Restated)
- Notes to Consolidated Financial Statements for the Years Ended December 31, 2002, 2001 (Restated), and 2000 (Restated)

**(a)-2. Financial Statement Schedules**

Schedule II — Valuation and Qualifying Accounts

(b) **Reports on Form 8-K**

The registrant filed the following reports on Form 8-K during the quarter ended December 31, 2002:

<u>Date of Report</u>	<u>Date Filed</u>	<u>Item Reported</u>
October 2, 2002	October 3, 2002	5,7
October 31, 2002	November 5, 2002	5,7
November 5, 2002	November 6, 2002	5,7
December 18, 2002	December 19, 2002	5,7

(c) **Exhibits**

The following exhibits are filed herewith unless otherwise indicated:

<u>Exhibit Number</u>	<u>Description</u>
3.1.1	Amended and Restated Certificate of Incorporation of Calpine Corporation.(a)
3.1.2	Certificate of Correction of Calpine Corporation.(b)
3.1.3	Certificate of Amendment of Amended and Restated Certificate of Incorporation of Calpine Corporation.(c)
3.1.4	Certificate of Designation of Series A Participating Preferred Stock of Calpine Corporation.(b)
3.1.5	Amended Certificate of Designation of Series A Participating Preferred Stock of Calpine Corporation.(b)
3.1.6	Amended Certificate of Designation of Series A Participating Preferred Stock of Calpine Corporation.(c)
3.1.7	Certificate of Designation of Special Voting Preferred Stock of Calpine Corporation.(d)
3.1.8	Certificate of Ownership and Merger Merging Calpine Natural Gas GP, Inc. into Calpine Corporation.(e)
3.1.9	Certificate of Ownership and Merger Merging Calpine Natural Gas Company into Calpine Corporation.(e)
3.1.10	Amended and Restated By-laws of Calpine Corporation.(f)
4.1.1	Indenture dated as of May 16, 1996, between the Company and Fleet National Bank, as Trustee, including form of Notes.(g)
4.1.2	First Supplemental Indenture dated as of August 1, 2000, between the Company and State Street Bank and Trust Company (successor trustee to Fleet National Bank), as Trustee.(b)
4.2.1	Indenture dated as of July 8, 1997, between the Company and The Bank of New York, as Trustee, including form of Notes.(h)
4.2.2	Supplemental Indenture dated as of September 10, 1997, between the Company and The Bank of New York, as Trustee.(i)
4.2.3	Second Supplemental Indenture dated as of July 31, 2000, between the Company and The Bank of New York, as Trustee.(b)
4.3.1	Indenture dated as of March 31, 1998, between the Company and The Bank of New York, as Trustee, including form of Notes.(j)
4.3.2	Supplemental Indenture dated as of July 24, 1998, between the Company and The Bank of New York, as Trustee.(j)
4.3.3	Second Supplemental Indenture dated as of July 31, 2000, between the Company and The Bank of New York, as Trustee.(b)
4.4.1	Indenture dated as of March 29, 1999, between the Company and The Bank of New York, as Trustee, including form of Notes.(k)
4.4.2	First Supplemental Indenture dated as of July 31, 2000, between the Company and The Bank of New York, as Trustee.(b)

<u>Exhibit Number</u>	<u>Description</u>
4.5.1	Indenture dated as of March 29, 1999, between the Company and The Bank of New York, as Trustee, including form of Notes.(k)
4.5.2	First Supplemental Indenture dated as of July 31, 2000, between the Company and The Bank of New York, as Trustee.(b)
4.6.1	Indenture dated as of August 10, 2000, between the Company and Wilmington Trust Company, as Trustee.(l)
4.6.2	First Supplemental Indenture dated as of September 28, 2000, between the Company and Wilmington Trust Company, as Trustee.(b)
4.7	Indenture, dated as of April 30, 2001, between the Company and Wilmington Trust Company, as Trustee.(m)
4.8	Amended and Restated Indenture dated as of October 16, 2001, between Calpine Canada Energy Finance ULC and Wilmington Trust Company, as Trustee.(n)
4.9	Guarantee Agreement dated as of April 25, 2001, between the Company and Wilmington Trust Company, as Trustee.(o)
4.10	First Amendment, dated as of October 16, 2001, to Guarantee Agreement dated as of April 25, 2001, between the Company and Wilmington Trust Company, as Trustee.(n)
4.11	Indenture dated as of October 18, 2001, between Calpine Canada Energy Finance II ULC and Wilmington Trust Company, as Trustee.(n)
4.12	First Supplemental Indenture, dated as of October 18, 2001, between Calpine Canada Energy Finance II ULC and Wilmington Trust Company, as Trustee.(n)
4.13	Guarantee Agreement dated as of October 18, 2001, between the Company and Wilmington Trust Company, as Trustee.(n)
4.14	First Amendment, dated as of October 18, 2001, to Guarantee Agreement dated as of October 18, 2001, between the Company and Wilmington Trust Company, as Trustee.(n)
4.15	Amended and Restated Rights Agreement, dated as of September 19, 2001, between Calpine Corporation and Equiserve Trust Company, N.A., as Rights Agent.(p)
4.16	Form of Exchangeable Share Provisions and Other Provisions to Be Included in the Articles of Calpine Canada Holdings Ltd. (included as Exhibit B to Exhibit 10.1.2).(d)
4.17	Form of Support Agreement between the Company and Calpine Canada Holdings Ltd. (included as Exhibit C to Exhibit 10.1.1).(d)
4.18	HIGH TIDES I.
4.18.1	Certificate of Trust of Calpine Capital Trust, a Delaware statutory trust, dated September 29, 1999.(q)
4.18.2	Corrected Certificate of Certificate of Trust of Calpine Capital Trust, a Delaware statutory trust, filed October 4, 1999.(q)
4.18.3	Declaration of Trust of Calpine Capital Trust, dated as of October 4, 1999, among Calpine Corporation, as Depositor, The Bank of New York (Delaware), as Delaware Trustee, The Bank of New York, as Property Trustee, and the Administrative Trustees named therein.(q)
4.18.4	Indenture, dated as of November 2, 1999, between Calpine Corporation and The Bank of New York, as Trustee, including form of Debenture.(q)
4.18.5	Remarketing Agreement, dated November 2, 1999, among Calpine Corporation, Calpine Capital Trust, The Bank of New York, as Tender Agent, and Credit Suisse First Boston Corporation, as Remarketing Agent.(q)
4.18.6	Amended and Restated Declaration of Trust of Calpine Capital Trust, dated as of November 2, 1999, among Calpine Corporation, as Depositor and Debenture Issuer, The Bank of New York (Delaware), as Delaware Trustee, and The Bank of New York, as Property Trustee, and the Administrative Trustees named therein, including form of Preferred Security and form of Common Security.(q)

<u>Exhibit Number</u>	<u>Description</u>
4.18.7	Preferred Securities Guarantee Agreement, dated as of November 2, 1999, between Calpine Corporation and The Bank of New York, as Guarantee Trustee.(q)
4.19	HIGH TIDES II.
4.19.1	Certificate of Trust of Calpine Capital Trust II, a Delaware statutory trust, filed January 25, 2000.(r)
4.19.2	Declaration of Trust of Calpine Capital Trust II, dated as of January 24, 2000, among Calpine Corporation, as Depositor and Debenture Issuer, The Bank of New York (Delaware), as Delaware Trustee, The Bank of New York, as Property Trustee, and the Administrative Trustees named therein.(r)
4.19.3	Indenture, dated as of January 31, 2000, between Calpine Corporation and The Bank of New York, as Trustee, including form of Debenture.(r)
4.19.4	Remarketing Agreement, dated as of January 31, 2000, among Calpine Corporation, Calpine Capital Trust II, The Bank of New York, as Tender Agent, and Credit Suisse First Boston Corporation, as Remarketing Agent.(r)
4.19.5	Registration Rights Agreement, dated January 31, 2000, among Calpine Corporation, Calpine Capital Trust II, Credit Suisse First Boston Corporation and ING Barings LLC.(r)
4.19.6	Amended and Restated Declaration of Trust of Calpine Capital Trust II, dated as of January 31, 2000, among Calpine Corporation, as Depositor and Debenture Issuer, The Bank of New York (Delaware), as Delaware Trustee, The Bank of New York, as Property Trustee, and the Administrative Trustees named therein, including form of Preferred Security and form of Common Security.(r)
4.19.7	Preferred Securities Guarantee Agreement, dated as of January 31, 2000, between Calpine Corporation and The Bank of New York, as Guarantee Trustee.(r)
4.20	HIGH TIDES III.
4.20.1	Amended and Restated Certificate of Trust of Calpine Capital Trust III, a Delaware statutory trust, filed July 19, 2000.(s)
4.20.2	Declaration of Trust of Calpine Capital Trust III dated June 28, 2000, among the Company, as Depositor and Debenture Issuer, The Bank of New York (Delaware), as Delaware Trustee, The Bank of New York, as Property Trustee and the Administrative Trustees named therein.(s)
4.20.3	Amendment No. 1 to the Declaration of Trust of Calpine Capital Trust III dated July 19, 2000, among the Company, as Depositor and Debenture Issuer, Wilmington Trust Company, as Delaware Trustee, Wilmington Trust Company, as Property Trustee, and the Administrative Trustees named therein.(s)
4.20.4	Indenture dated as of August 9, 2000, between the Company and Wilmington Trust Company, as Trustee.(s)
4.20.5	Remarketing Agreement dated as of August 9, 2000, among the Company, Calpine Capital Trust III, Wilmington Trust Company, as Tender Agent, and Credit Suisse First Boston Corporation, as Remarketing Agent.(s)
4.20.6	Registration Rights Agreement dated as August 9, 2000, between the Company, Calpine Capital Trust III, Credit Suisse First Boston Corporation, ING Barings LLC and CIBC World Markets Corp.(s)
4.20.7	Amended and Restated Declaration of Trust of Calpine Capital Trust III dated as of August 9, 2000, the Company, as Depositor and Debenture Issuer, Wilmington Trust Company, as Delaware Trustee, Wilmington Trust Company, as Property Trustee, and the Administrative Trustees named therein, including the form of Preferred Security and form of Common Security.(s)
4.20.8	Preferred Securities Guarantee Agreement dated as of August 9, 2000, between the Company, as Guarantor, and Wilmington Trust Company, as Guarantee Trustee.(s)
4.21	PASS THROUGH CERTIFICATES (TIVERTON AND RUMFORD).

<u>Exhibit Number</u>	<u>Description</u>
4.21.1	Pass Through Trust Agreement dated as of December 19, 2000, among Tiverton Power Associates Limited Partnership, Rumford Power Associates Limited Partnership and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including the form of Certificate.(b)
4.21.2	Participation Agreement dated as of December 19, 2000, among the Company, Tiverton Power Associates Limited Partnership, Rumford Power Associates Limited Partnership, PMCC Calpine New England Investment LLC, PMCC Calpine NEIM LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee.(b)
4.21.3	Appendix A — Definitions and Rules of Interpretation.(b)
4.21.4	Indenture of Trust, Mortgage and Security Agreement, dated as of December 19, 2000, between PMCC Calpine New England Investment LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, including the forms of Lessor Notes.(b)
4.21.5	Calpine Guaranty and Payment Agreement (Tiverton) dated as of December 19, 2000, by Calpine, as Guarantor, to PMCC Calpine New England Investment LLC, PMCC Calpine NEIM LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(b)
4.21.6	Calpine Guaranty and Payment Agreement (Rumford) dated as of December 19, 2000, by Calpine, as Guarantor, to PMCC Calpine New England Investment LLC, PMCC Calpine NEIM LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(b)
4.22	PASS THROUGH CERTIFICATES (SOUTH POINT, BROAD RIVER AND ROCKGEN).
4.22.1	Pass Through Trust Agreement A dated as of October 18, 2001, among South Point Energy Center, LLC, Broad River Energy LLC, RockGen Energy LLC and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including the form of 8.400% Pass Through Certificate, Series A.(f)
4.22.2	Pass Through Trust Agreement B dated as of October 18, 2001, among South Point Energy Center, LLC, Broad River Energy LLC, RockGen Energy LLC and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including the form of 9.825% Pass Through Certificate, Series B.(f)
4.22.3	Participation Agreement (SP-1) dated as of October 18, 2001, among the Company, South Point Energy Center, LLC, South Point OL-1, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-1, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(f)
4.22.4	Participation Agreement (SP-2) dated as of October 18, 2001, among the Company, South Point Energy Center, LLC, South Point OL-2, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-2, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(f)
4.22.5	Participation Agreement (SP-3) dated as of October 18, 2001, among the Company, South Point Energy Center, LLC, South Point OL-3, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-3, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(f)

<u>Exhibit Number</u>	<u>Description</u>
4.22.6	Participation Agreement (SP-4) dated as of October 18, 2001, among the Company, South Point Energy Center, LLC, South Point OL-4, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-4, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(f)
4.22.7	Participation Agreement (BR-1) dated as of October 18, 2001, among the Company, Broad River Energy LLC, Broad River OL-1, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-1, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(f)
4.22.8	Participation Agreement (BR-2) dated as of October 18, 2001, among the Company, Broad River Energy LLC, Broad River OL-2, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-2, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(f)
4.22.9	Participation Agreement (BR-3) dated as of October 18, 2001, among the Company, Broad River Energy LLC, Broad River OL-3, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-3, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(f)
4.22.10	Participation Agreement (BR-4) dated as of October 18, 2001, among the Company, Broad River Energy LLC, Broad River OL-4, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-4, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(f)
4.22.11	Participation Agreement (RG-1) dated as of October 18, 2001, among the Company, RockGen Energy LLC, RockGen OL-1, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-1, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(f)
4.22.12	Participation Agreement (RG-2) dated as of October 18, 2001, among the Company, RockGen Energy LLC, RockGen OL-2, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-2, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(f)
4.22.13	Participation Agreement (RG-3) dated as of October 18, 2001, among the Company, RockGen Energy LLC, RockGen OL-3, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-3, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(f)

<u>Exhibit Number</u>	<u>Description</u>
4.22.14	Participation Agreement (RG-4) dated as of October 18, 2001, among the Company, RockGen Energy LLC, RockGen OL-4, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-4, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(f)
4.22.15	Indenture of Trust, Deed of Trust, Assignment of Rents and Leases, Security Agreement and Financing Statement, dated as of October 18, 2001, between South Point OL-1, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee and Account Bank, including the form of South Point Lessor Notes.(f)
4.22.16	Indenture of Trust, Deed of Trust, Assignment of Rents and Leases, Security Agreement and Financing Statement, dated as of October 18, 2001, between South Point OL-2, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee and Account Bank, including the form of South Point Lessor Notes.(f)
4.22.17	Indenture of Trust, Deed of Trust, Assignment of Rents and Leases, Security Agreement and Financing Statement, dated as of October 18, 2001, between South Point OL-3, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee and Account Bank, including the form of South Point Lessor Notes.(f)
4.22.18	Indenture of Trust, Deed of Trust, Assignment of Rents and Leases, Security Agreement and Financing Statement, dated as of October 18, 2001, between South Point OL-4, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee and Account Bank, including the form of South Point Lessor Notes.(f)
4.22.19	Indenture of Trust, Mortgage, Security Agreement and Fixture Filing, dated as of October 18, 2001, between Broad River OL-1, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, Mortgagee and Account Bank, including the form of Broad River Lessor Notes.(f)
4.22.20	Indenture of Trust, Mortgage, Security Agreement and Fixture Filing, dated as of October 18, 2001, between Broad River OL-2, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, Mortgagee and Account Bank, including the form of Broad River Lessor Notes.(f)
4.22.21	Indenture of Trust, Mortgage, Security Agreement and Fixture Filing, dated as of October 18, 2001, between Broad River OL-3, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, Mortgagee and Account Bank, including the form of Broad River Lessor Notes.(f)
4.22.22	Indenture of Trust, Mortgage, Security Agreement and Fixture Filing, dated as of October 18, 2001, between Broad River OL-4, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, Mortgagee and Account Bank, including the form of Broad River Lessor Notes.(f)
4.22.23	Indenture of Trust, Mortgage and Security Agreement, dated as of October 18, 2001, between RockGen OL-1, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee and Account Bank, including the form of RockGen Lessor Notes.(f)
4.22.24	Indenture of Trust, Mortgage and Security Agreement, dated as of October 18, 2001, between RockGen OL-2, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee and Account Bank, including the form of RockGen Lessor Notes.(f)
4.22.25	Indenture of Trust, Mortgage and Security Agreement, dated as of October 18, 2001, between RockGen OL-3, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee and Account Bank, including the form of RockGen Lessor Notes.(f)

<u>Exhibit Number</u>	<u>Description</u>
4.22.26	Indenture of Trust, Mortgage and Security Agreement, dated as of October 18, 2001, between RockGen OL-4, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee and Account Bank, including the form of RockGen Lessor Notes.(f)
4.22.27	Calpine Guaranty and Payment Agreement (South Point SP-1) dated as of October 18, 2001, by Calpine, as Guarantor, to South Point OL-1, LLC, SBR OP-1, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(f)
4.22.28	Calpine Guaranty and Payment Agreement (South Point SP-2) dated as of October 18, 2001, by Calpine, as Guarantor, to South Point OL-2, LLC, SBR OP-2, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(f)
4.22.29	Calpine Guaranty and Payment Agreement (South Point SP-3) dated as of October 18, 2001, by Calpine, as Guarantor, to South Point OL-3, LLC, SBR OP-3, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(f)
4.22.30	Calpine Guaranty and Payment Agreement (South Point SP-4) dated as of October 18, 2001, by Calpine, as Guarantor, to South Point OL-4, LLC, SBR OP-4, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(f)
4.22.31	Calpine Guaranty and Payment Agreement (Broad River BR-1) dated as of October 18, 2001, by Calpine, as Guarantor, to Broad River OL-1, LLC, SBR OP-1, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(f)
4.22.32	Calpine Guaranty and Payment Agreement (Broad River BR-2) dated as of October 18, 2001, by Calpine, as Guarantor, to Broad River OL-2, LLC, SBR OP-2, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(f)
4.22.33	Calpine Guaranty and Payment Agreement (Broad River BR-3) dated as of October 18, 2001, by Calpine, as Guarantor, to Broad River OL-3, LLC, SBR OP-3, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(f)
4.22.34	Calpine Guaranty and Payment Agreement (Broad River BR-4) dated as of October 18, 2001, by Calpine, as Guarantor, to Broad River OL-4, LLC, SBR OP-4, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(f)
4.22.35	Calpine Guaranty and Payment Agreement (RockGen RG-1) dated as of October 18, 2001, by Calpine, as Guarantor, to RockGen OL-1, LLC, SBR OP-1, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(f)
4.22.36	Calpine Guaranty and Payment Agreement (RockGen RG-2) dated as of October 18, 2001, by Calpine, as Guarantor, to RockGen OL-2, LLC, SBR OP-2, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(f)
4.22.37	Calpine Guaranty and Payment Agreement (RockGen RG-3) dated as of October 18, 2001, by Calpine, as Guarantor, to RockGen OL-3, LLC, SBR OP-3, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(f)
4.22.38	Calpine Guaranty and Payment Agreement (RockGen RG-4) dated as of October 18, 2001, by Calpine, as Guarantor, to RockGen OL-4, LLC, SBR OP-4, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(f)

<u>Exhibit Number</u>	<u>Description</u>
9.1	Form of Voting and Exchange Trust Agreement between the Company, Calpine Canada Holdings Ltd. and CIBC Mellon Trust Company, as Trustee (included as Exhibit D to Exhibit 10.1.1).(d)
10.1	Purchase Agreements.
10.1.1	Combination Agreement, dated as of February 7, 2001, by and between the Company and Encal Energy Ltd.(d)
10.1.2	Amending Agreement to the Combination Agreement, dated as of March 16, 2001, between the Company and Encal Energy Ltd.(t)
10.1.3	Form of Plan of Arrangement Under Section 186 of the Business Corporations Act (Alberta) Involving and Affecting Encal Energy Ltd. and the Holders of its Common Shares and Options (included as Exhibit A to Exhibit 10.1.1).(d)
10.2	Financing Agreements.
10.2.1	Amended and Restated Calpine Construction Finance Company Financing Agreement (“CCFC I”), dated as of February 15, 2001.(d)(u)
10.2.2	Calpine Construction Finance Company Financing Agreement (“CCFC II”), dated as of October 16, 2000.(b)(v)
10.2.3	Second Amended and Restated Credit Agreement, dated as of May 23, 2000 (“Second Amended and Restated Credit Agreement”), among the Company, Bayerische Landesbank, as Co-Arranger and Syndication Agent, The Bank of Nova Scotia, as Lead Arranger and Administrative Agent, and the Lenders named therein.(w)
10.2.4	First Amendment and Waiver to Second Amended and Restated Credit Agreement, dated as of April 19, 2001, among the Company, The Bank of Nova Scotia, as Administrative Agent, and the Lenders named therein.(f)
10.2.5	Second Amendment to Second Amended and Restated Credit Agreement, dated as of March 8, 2002, among the Company, The Bank of Nova Scotia, as Administrative Agent, and the Lenders named therein.(f)
10.2.6	Third Amendment to Second Amended and Restated Credit Agreement, dated as of May 9, 2002, among the Company, The Bank of Nova Scotia, as Administrative Agent, and the Lenders named therein.(e)
10.2.7	Fourth Amendment to Second Amended and Restated Credit Agreement, dated as of September 26, 2002, among the Company, The Bank of Nova Scotia, as Administrative Agent, and the Lenders named therein.(x)
10.2.8	Fifth Amendment to Second Amended and Restated Credit Agreement, dated as of March 12, 2003, among the Company, The Bank of Nova Scotia, as Administrative Agent, and the Lenders named therein.(*)
10.2.9	Credit Agreement, dated as of March 8, 2002, among the Company, the Lenders named therein, The Bank of Nova Scotia and Bayerische Landesbank Girozentrale, as lead arrangers and bookrunners, Salomon Smith Barney Inc. and Deutsche Banc Alex. Brown Inc., as lead arrangers and bookrunners, Bank of America, National Association, and Credit Suisse First Boston, Cayman Islands Branch, as lead arrangers and syndication agents, TD Securities (USA) Inc., as lead arranger, The Bank of Nova Scotia, as joint administrative agent and funding agent, and Citicorp USA, Inc., as joint administrative agent.(f)
10.2.10	First Amendment to Credit Agreement, dated as of May 9, 2002, among the Company, The Bank of Nova Scotia, as Joint Administrative Agent and Funding Agent, Citicorp USA, Inc., as Joint Administrative Agent, and the Lenders named therein.(e)
10.2.11	Increase in Term B Loan Commitment Amount Notice, effective as of May 31, 2002, by The Bank of Nova Scotia and Citicorp USA, Inc., as Administrative Agents.(y)
10.2.12	Assignment and Security Agreement, dated as of March 8, 2002, by the Company in favor of The Bank of Nova Scotia, as administrative agent for each of the Lender Parties named therein.(f)

<u>Exhibit Number</u>	<u>Description</u>
10.2.13	Pledge Agreement, dated as of March 8, 2002, by the Company in favor of The Bank of Nova Scotia, as Agent for the Lender Parties named therein.(f)
10.2.14	Amendment Number One to Pledge Agreement, dated as of May 9, 2002, among the Company and The Bank of Nova Scotia, as Joint Administrative Agent and Funding Agent.(e)
10.2.15	Pledge Agreement, dated as of March 8, 2002, by Quintana Minerals (USA), Inc., JOQ Canada, Inc. and Quintana Canada Holdings, LLC in favor of The Bank of Nova Scotia, as Agent for the Lender Parties named therein.(f)
10.2.16	Guarantee, dated as of March 8, 2002, by Quintana Minerals (USA), Inc., JOQ Canada, Inc. and Quintana Canada Holdings, LLC, in favor of each of the Lender Parties named therein.(f)
10.2.17	First Amendment Pledge Agreement, dated as of May 9, 2002, by the Company in favor of The Bank of Nova Scotia, as Agent for each of the Lender Parties named therein.(e)
10.2.18	First Amendment Pledge Agreement (Membership Interests), dated as of May 9, 2002, by the Company in favor of The Bank of Nova Scotia, as Agent for each of the Lender Parties named therein.(e)
10.2.19	Note Pledge Agreement, dated as of May 9, 2002, by the Company in favor of The Bank of Nova Scotia, as Agent for each of the Lender Parties named therein.(e)
10.2.20	Hazardous Materials Undertaking and Indemnity (Multistate), dated as of May 9, 2002, by the Company in favor of The Bank of Nova Scotia, as Agent.(y)
10.2.21	Hazardous Materials Undertaking and Indemnity (California), dated as of May 9, 2002, by the Company in favor of The Bank of Nova Scotia, as Agent.(y)
10.2.22	Form of Mortgage, Deed of Trust, Assignment, Security Agreement, Financing Statement and Fixture Filing (Multistate), from the Company to Jon Burckin and Kemp Leonard, as Trustees, and The Bank of Nova Scotia, as Agent.(y)
10.2.23	Form of Deed of Trust with Power of Sale, Assignment of Production, Security Agreement, Financing Statement and Fixture Filing (California), dated as of May 1, 2002, from the Company to Chicago Title Insurance Co.(y)
10.2.24	Form of Mortgage, Deed of Trust, Assignment, Security Agreement, Financing Statement and Fixture Filing (Colorado), dated as of May 1, 2002, from the Company to Kemp Leonard and John Quick, as Trustees, and The Bank of Nova Scotia, as Agent.(y)
10.2.25	Form of Mortgage, Assignment, Security Agreement and Financing Statement (Louisiana), dated as of May 1, 2002, from the Company to The Bank of Nova Scotia, as Agent.(y)
10.2.26	Form of Mortgage, Deed of Trust, Assignment, Security Agreement, Financing Statement and Fixture Filing (New Mexico), dated as of May 1, 2002, from the Company to Kemp Leonard and John Quick, as Trustees, and The Bank of Nova Scotia, as Agent.(y)
10.3	Other Agreements.
10.3.1	Calpine Corporation Stock Option Program and forms of agreements there under.(z) (bb)
10.3.2	Calpine Corporation 1996 Stock Incentive Plan and forms of agreements there under.(aa) (bb)
10.3.3	Employment Agreement, dated as of January 1, 2000, between Calpine Corporation and Mr. Peter Cartwright.(r) (bb)
10.3.4	Employment Agreement, dated as of January 1, 2000, between Calpine Corporation and Ms. Ann B. Curtis.(f) (bb)
10.3.5	Employment Agreement, dated as of January 1, 2000, between Calpine Corporation and Mr. Ron A. Walter.(f) (bb)
10.3.6	Employment Agreement, dated as of January 1, 2000, between Calpine Corporation and Mr. Robert D. Kelly.(f) (bb)
10.3.7	Employment Agreement, dated as of January 1, 2000, between Calpine Corporation and Mr. Thomas R. Mason.(f) (bb)
10.3.8	Calpine Corporation Annual Management Incentive Plan.(cc) (bb)

<u>Exhibit Number</u>	<u>Description</u>
10.3.9	\$500,000 Promissory Note Secured by Deed of Trust made by Thomas R. Mason and Debra J. Mason in favor of Calpine Corporation.(cc) (bb)
10.3.10	2000 Employee Stock Purchase Plan (dd) (bb)
10.4.1	Form of Indemnification Agreement for directors and officers.(aa) (bb)
10.4.2	Form of Indemnification Agreement for directors and officers.(f) (bb)
12.1	Statement on Computation of Ratio of Earnings to Fixed Charges.(*)
21.1	Subsidiaries of the Company.(*)
23.1	Consent of Deloitte & Touche LLP, Independent Auditors.(*)
23.2	Consent of Ernst & Young LLP, Independent Chartered Accountants.(*)
23.3	Consent of Netherland, Sewell & Associates, Inc., independent engineer.(*)
23.4	Consent of Gilbert Laustsen Jung Associates, Ltd., independent engineer.(*)
24.1	Power of Attorney of Officers and Directors of Calpine Corporation (set forth on the signature pages of this report).(*)
99.1	Certification of Chief Executive Officer and Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.(*)

(\*) Filed herewith.

- (a) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-3 (Registration No. 333-40652) filed with the SEC on June 30, 2000.
- (b) Incorporated by reference to Calpine Corporation's Annual Report on Form 10-K for the year ended December 31, 2000, filed with the SEC on March 15, 2001.
- (c) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-3 (Registration No. 333-66078) filed with the SEC on July 27, 2001.
- (d) Incorporated by reference to Calpine Corporation's Quarterly Report on Form 10-Q dated March 31, 2001, filed with the SEC on May 15, 2001.
- (e) Incorporated by reference to Calpine Corporation's Quarterly Report on Form 10-Q dated March 31, 2002, filed with the SEC on May 15, 2002.
- (f) Incorporated by reference to Calpine Corporation's Annual Report on Form 10-K dated December 31, 2001, filed with the SEC on March 29, 2002.
- (g) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-4 (Registration Statement No. 333-06259) filed with the SEC on June 19, 1996.
- (h) Incorporated by reference to Calpine Corporation's Quarterly Report on Form 10-Q dated June 30, 1997, filed with the SEC on August 14, 1997.
- (i) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-4 (Registration Statement No. 333-41261) filed with the SEC on November 28, 1997.
- (j) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-4 (Registration Statement No. 333-61047) filed with the SEC on August 10, 1998.
- (k) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-3/A (Registration Statement No. 333-72583) filed with the SEC on March 8, 1999.
- (l) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-3 (Registration No. 333-76880) filed with the SEC on January 17, 2002.
- (m) Incorporated by reference to Calpine Corporation's Current Report on Form 8-K dated October 16, 2001, filed with the SEC on November 13, 2001.
- (n) Incorporated by reference to Calpine Corporation's Current Report on Form 8-K dated October 16, 2001, filed with the SEC on November 13, 2001.

- (o) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-3/A (Registration No. 333-57338) filed with the SEC on April 19, 2001.
- (p) Incorporated by reference to Calpine Corporation's Registration Statement on Form 8-A/A (Registration No. 001-12079) filed with the SEC on September 28, 2001.
- (q) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-3/A (Registration Statement No. 333-87427) filed with the SEC on October 26, 1999.
- (r) Incorporated by reference to Calpine Corporation's Annual Report on Form 10-K for the year ended December 31, 1999, filed with the SEC on February 29, 2000.
- (s) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-3 (Registration Statement No. 333-47068) filed with the SEC on September 29, 2000.
- (t) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-3/A (Registration Statement No. 333-56712) filed with the SEC on April 17, 2001.
- (u) Approximately 24 pages of this exhibit have been omitted pursuant to a request for confidential treatment. The omitted language has been filed separately with the SEC.
- (v) Approximately 71 pages of this exhibit have been omitted pursuant to a request for confidential treatment. The omitted language has been filed separately with the SEC.
- (w) Incorporated by reference to Calpine Corporation's Current Report on Form 8-K dated July 25, 2000, filed with the SEC on August 9, 2000.
- (x) Incorporated by reference to Calpine Corporation's Quarterly Report on Form 10-Q dated September 30, 2002, filed with the SEC on November 14, 2002.
- (y) Incorporated by reference to Calpine Corporation's Quarterly Report on Form 10-Q dated June 30, 2002, filed with the SEC on August 12, 2002.
- (z) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-1 (Registration Statement No. 33-73160) filed with the SEC on December 20, 1993.
- (aa) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-1/A (Registration Statement No. 333-07497) filed with the SEC on August 22, 1996.
- (bb) Management contract or compensatory plan or arrangement.
- (cc) Incorporated by reference to Calpine Corporation's Current Report on Form 8-K dated March 30, 2000, filed with the SEC on April 3, 2000.
- (dd) Incorporated by reference to Calpine Corporation's Definitive Proxy Statement on Schedule 14A dated April 13, 2000, filed with the SEC on April 13, 2000.

## SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

CALPINE CORPORATION

By:           /s/ ROBERT D. KELLY            
                    Robert D. Kelly  
                    *Executive Vice President and*  
                    *Chief Financial Officer*

*Date: March 31, 2003*

## POWER OF ATTORNEY

KNOW ALL PERSONS BY THESE PRESENTS: That the undersigned officers and directors of Calpine Corporation do hereby constitute and appoint Peter Cartwright and Ann B. Curtis, and each of them, the lawful attorney and agent or attorneys and agents with power and authority to do any and all acts and things and to execute any and all instruments which said attorneys and agents, or either of them, determine may be necessary or advisable or required to enable Calpine Corporation to comply with the Securities and Exchange Act of 1934, as amended, and any rules or regulations or requirements of the Securities and Exchange Commission in connection with this Form 10-K Annual Report. Without limiting the generality of the foregoing power and authority, the powers granted include the power and authority to sign the names of the undersigned officers and directors in the capacities indicated below to this Form 10-K Annual Report or amendments or supplements thereto, and each of the undersigned hereby ratifies and confirms all that said attorneys and agents, or either of them, shall do or cause to be done by virtue hereof. This Power of Attorney may be signed in several counterparts.

IN WITNESS WHEREOF, each of the undersigned has executed this Power of Attorney as of the date indicated opposite the name.

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

<u>Signature</u>	<u>Title</u>	<u>Date</u>
<u>          /s/ PETER CARTWRIGHT          </u> Peter Cartwright	Chairman, President, Chief Executive and Director (Principal Executive Officer)	March 31, 2003
<u>          /s/ ANN B. CURTIS          </u> Ann B. Curtis	Executive Vice President, Vice Chairman and Director	March 31, 2003
<u>          /s/ ROBERT D. KELLY          </u> Robert D. Kelly	Executive Vice President and Chief Financial Officer (Principal Financial Officer)	March 31, 2003
<u>          /s/ CHARLES B. CLARK, JR.          </u> Charles B. Clark, Jr.	Senior Vice President and Corporate Controller (Principal Accounting Officer)	March 31, 2003

<u>Signature</u>	<u>Title</u>	<u>Date</u>
<u>/s/ KENNETH T. DERR</u> Kenneth T. Derr	Director	March 31, 2003
<u>/s/ JEFFREY E. GARTEN</u> Jeffrey E. Garten	Director	March 31, 2003
<u>/s/ GERALD GREENWALD</u> Gerald Greenwald	Director	March 31, 2003
<u>/s/ SUSAN C. SCHWAB</u> Susan C. Schwab	Director	March 31, 2003
<u>/s/ GEORGE J. STATHAKIS</u> George J. Stathakis	Director	March 31, 2003
<u>/s/ JOHN O. WILSON</u> John O. Wilson	Director	March 31, 2003

## CERTIFICATIONS

### Certificate of the Chairman, President and Chief Executive Officer

I, Peter Cartwright, the Chairman, President and Chief Executive Officer of Calpine Corporation, certify that:

1. I have reviewed this annual report on Form 10-K of Calpine Corporation (the “registrant”);
2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;
3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;
4. The registrant’s other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:
  - a) Designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;
  - b) Evaluated the effectiveness of the registrant’s disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the “Evaluation Date”); and
  - c) Presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;
5. The registrant’s other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant’s auditors and the audit committee of registrant’s board of directors (or persons performing the equivalent function):
  - a) All significant deficiencies in the design or operation of internal controls which could adversely affect the registrant’s ability to record, process, summarize and report financial data and have identified for the registrant’s auditors any material weaknesses in internal controls; and
  - b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal controls; and
6. The registrant’s other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 31, 2003

/s/ PETER CARTWRIGHT

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Peter Cartwright  
Chairman, President and  
Chief Executive Officer  
Calpine Corporation

### **Certificate of the Executive Vice President and Chief Financial Officer**

I, Robert D. Kelly, the Executive Vice President and Chief Financial Officer of Calpine Corporation, certify that:

1. I have reviewed this annual report on Form 10-K of Calpine Corporation (the “registrant”);
2. Based on my knowledge, this annual report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this annual report;
3. Based on my knowledge, the financial statements, and other financial information included in this annual report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this annual report;
4. The registrant’s other certifying officers and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-14 and 15d-14) for the registrant and we have:
  - a) Designed such disclosure controls and procedures to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this annual report is being prepared;
  - b) Evaluated the effectiveness of the registrant’s disclosure controls and procedures as of a date within 90 days prior to the filing date of this annual report (the “Evaluation Date”); and
  - c) Presented in this annual report our conclusions about the effectiveness of the disclosure controls and procedures based on our evaluation as of the Evaluation Date;
5. The registrant’s other certifying officers and I have disclosed, based on our most recent evaluation, to the registrant’s auditors and the audit committee of registrant’s board of directors (or persons performing the equivalent function):
  - a) All significant deficiencies in the design or operation of internal controls which could adversely affect the registrant’s ability to record, process, summarize and report financial data and have identified for the registrant’s auditors any material weaknesses in internal controls; and
  - b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant’s internal controls; and
6. The registrant’s other certifying officers and I have indicated in this annual report whether there were significant changes in internal controls or in other factors that could significantly affect internal controls subsequent to the date of our most recent evaluation, including any corrective actions with regard to significant deficiencies and material weaknesses.

Date: March 31, 2003

/s/ ROBERT D. KELLY

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Robert D. Kelly  
Executive Vice President and  
Chief Financial Officer  
Calpine Corporation

**CALPINE CORPORATION AND SUBSIDIARIES**  
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**December 31, 2002**

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## INDEPENDENT AUDITORS' REPORT

To the Board of Directors  
and Stockholders of Calpine Corporation:

We have audited the consolidated balance sheets of Calpine Corporation and subsidiaries (the "Company") as of December 31, 2002 and 2001, and the related consolidated statements of operations, stockholders' equity, and cash flows for each of the three years in the period ended December 31, 2002. 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. The consolidated financial statements give retroactive effect to the merger of Calpine Corporation and Encal Energy Ltd. ("Encal") on April 19, 2001, which has been accounted for as a pooling of interests as discussed in Note 3 of the Notes to the Consolidated Financial Statements. We did not audit the related statements of operations, stockholders' equity, and cash flows of Encal for the year ended December 31, 2000, which statements reflect total revenues constituting 11.1% of consolidated total revenues for the year ended December 31, 2000. Such financial statements were audited by other auditors whose report has been furnished to us, and our opinion, insofar as it relates to the amounts included for Encal, is based solely on the report of such other auditors.

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

In our opinion, based on our audits and the report of other auditors, such consolidated financial statements present fairly, in all material respects, the consolidated financial position of Calpine Corporation and subsidiaries as of December 31, 2002 and 2001, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2002, in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 2 of the Notes to the Consolidated Financial Statements, in 2002, the Company adopted new accounting standards to account for the impairment of long-lived assets, discontinued operations, gains and losses on debt extinguishments and certain derivative contracts. Additionally, in 2002, the Company changed the method of reporting gains and losses associated with energy trading contracts from the gross to the net method and retroactively reclassified the consolidated statements of operations for 2001 and 2000. In 2001, as discussed in Note 3 of the Notes to the Consolidated Financial Statements, the Company adopted Statement of Financial Accounting Standards No. 133, *Accounting for Derivative Instruments and Hedging Activities*, as amended, and certain interpretations issued by the Derivatives Implementation Group of the Financial Accounting Standards Board.

As discussed in Note 2 of the Notes to the Consolidated Financial Statements, the accompanying 2001 and 2000 consolidated financial statements have been restated.

/s/ DELOITTE & TOUCHE LLP

San Jose, California

March 10, 2003

(March 26, 2003 as to paragraphs two, three and four of Note 29)

## 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, 2002 and 2001**

	<b>2002</b>	<b>2001</b>
	<b>Restated (1)</b>	
	<b>(In thousands, except share and per share amounts)</b>	
<b>ASSETS</b>		
Current assets:		
Cash and cash equivalents . . . . .	\$ 579,486	\$ 1,594,144
Accounts receivable, net of allowance of \$5,955 and \$15,422 . . . . .	747,004	966,707
Margin deposits and other prepaid expense . . . . .	152,726	451,374
Inventories . . . . .	106,536	82,801
Restricted cash . . . . .	176,716	102,633
Current derivative assets . . . . .	330,244	820,183
Current assets held for sale . . . . .	—	9,484
Other current assets . . . . .	143,318	95,850
	<u>2,236,030</u>	<u>4,123,176</u>
Restricted cash, net of current portion . . . . .	9,203	9,438
Notes receivable, net of current portion . . . . .	195,398	158,124
Project development costs . . . . .	118,513	405,835
Investments in power projects . . . . .	421,402	392,711
Deferred financing costs . . . . .	185,026	193,734
Prepaid lease, net of current portion . . . . .	301,603	142,887
Property, plant and equipment, net . . . . .	18,850,967	15,327,394
Goodwill, net . . . . .	34,589	29,375
Other intangible assets, net . . . . .	93,066	109,290
Long-term derivative assets . . . . .	496,028	578,775
Long-term assets held for sale . . . . .	—	332,080
Other assets . . . . .	285,167	134,408
	<u>\$23,226,992</u>	<u>\$21,937,227</u>

(1) See Note 2 to Consolidated Financial Statements regarding the restatement of financial statements.

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

	<u>2002</u>	<u>2001</u>
		Restated(1)
	(In thousands, except share and per share amounts)	
<b>LIABILITIES &amp; STOCKHOLDERS' EQUITY</b>		
Current liabilities:		
Accounts payable . . . . .	\$ 1,238,647	\$ 1,286,699
Accrued payroll and related expense . . . . .	48,322	57,285
Accrued interest payable . . . . .	189,336	185,727
Income taxes payable . . . . .	3,640	—
Notes payable and borrowings under lines of credit, current portion . . . . .	340,703	23,238
Capital lease obligation, current portion . . . . .	3,502	2,157
Construction/project financing, current portion . . . . .	1,307,291	—
Zero-Coupon Convertible Debentures Due 2021 . . . . .	—	878,000
Current derivative liabilities . . . . .	189,356	634,534
Current liabilities held for sale . . . . .	—	12,059
Other current liabilities . . . . .	246,334	171,855
Total current liabilities . . . . .	<u>3,567,131</u>	<u>3,251,554</u>
Term loan . . . . .	949,565	—
Notes payable and borrowings under lines of credit, net of current portion . . . . .	8,249	74,750
Capital lease obligation, net of current portion . . . . .	197,672	198,541
Construction/project financing, net of current portion . . . . .	3,212,022	4,080,495
Convertible Senior Notes Due 2006 . . . . .	1,200,000	1,100,000
Senior notes . . . . .	6,894,801	7,036,461
Deferred income taxes, net . . . . .	1,123,729	951,857
Deferred lease incentive . . . . .	53,732	57,236
Deferred revenue . . . . .	154,969	92,139
Long-term derivative liabilities . . . . .	528,400	862,842
Long-term liabilities held for sale . . . . .	—	7,488
Other liabilities . . . . .	175,636	87,269
Total liabilities . . . . .	<u>18,065,906</u>	<u>17,800,632</u>
Commitments and contingencies (see Note 26)		
Company-obligated mandatorily redeemable convertible preferred securities of subsidiary trusts . . . . .	1,123,969	1,122,924
Minority interests . . . . .	<u>185,203</u>	<u>45,542</u>
Stockholders' equity:		
Preferred stock, \$.001 par value per share; authorized 10,000,000 shares; issued and outstanding one share in 2002 and 2001 . . . . .	—	—
Common stock, \$.001 par value per share; authorized 1,000,000,000 shares; issued and outstanding 380,816,132 shares in 2002 and 307,058,751 shares in 2001 . . . . .	381	307
Additional paid-in capital . . . . .	2,802,503	2,040,833
Retained earnings . . . . .	1,286,487	1,167,869
Accumulated other comprehensive loss . . . . .	(237,457)	(240,880)
Total stockholders' equity . . . . .	<u>3,851,914</u>	<u>2,968,129</u>
Total liabilities and stockholders' equity . . . . .	<u>\$23,226,992</u>	<u>\$21,937,227</u>

(1) See Note 2 to Consolidated Financial Statements regarding the restatement of financial statements.

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,		
	2002	2001	2000
	Restated(1)      Restated(1)		
	(In thousands, except per share amounts)		
Revenue:			
Electric generation and marketing revenue			
Electricity and steam revenue .....	\$3,280,291	\$2,417,481	\$1,696,066
Sales of purchased power for hedging and optimization .....	<u>3,145,991</u>	<u>3,332,412</u>	<u>369,911</u>
Total electric generation and marketing revenue .....	6,426,282	5,749,893	2,065,977
Oil and gas production and marketing revenue			
Oil and gas sales .....	121,227	286,519	221,883
Sales of purchased gas for hedging and optimization .....	<u>870,466</u>	<u>526,517</u>	<u>87,119</u>
Total oil and gas production and marketing revenue .....	991,693	813,036	309,002
Trading revenue, net			
Realized revenue on power and gas trading transactions, net .....	26,090	29,145	—
Unrealized mark-to-market gain (loss) on power and gas transactions, net .....	<u>(4,605)</u>	<u>122,593</u>	<u>—</u>
Total trading revenue, net .....	21,485	151,738	—
Other revenue .....	<u>18,439</u>	<u>39,561</u>	<u>199</u>
Total revenue .....	<u>7,457,899</u>	<u>6,754,228</u>	<u>2,375,178</u>
Cost of revenue:			
Electric generation and marketing expense			
Plant operating expense .....	510,929	325,847	198,964
Royalty expense .....	17,615	27,493	32,326
Purchased power expense for hedging and optimization .....	<u>2,618,445</u>	<u>2,986,578</u>	<u>358,649</u>
Total electric generation and marketing expense .....	3,146,989	3,339,918	589,939
Oil and gas production and marketing expense			
Oil and gas production expense .....	97,895	90,882	66,369
Purchased gas expense for hedging and optimization .....	<u>821,065</u>	<u>492,587</u>	<u>107,591</u>
Total oil and gas production and marketing expense .....	918,960	583,469	173,960
Fuel expense .....	1,791,930	1,170,977	602,165
Depreciation, depletion and amortization expense .....	459,465	311,302	195,863
Operating lease expense .....	111,022	99,519	63,463
Other expense .....	<u>12,593</u>	<u>15,548</u>	<u>2,019</u>
Total cost of revenue .....	<u>6,440,959</u>	<u>5,520,733</u>	<u>1,627,409</u>

(1) See Note 2 to Consolidated Financial Statements regarding the restatement of financial statements.

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

	<b>For the Years Ended December 31,</b>		
	<b>2002</b>	<b>2001</b>	<b>2000</b>
	<b>Restated(1)</b>		<b>Restated(1)</b>
	<b>(In thousands, except per share amounts)</b>		
Gross profit .....	1,016,940	1,233,495	747,769
Income from unconsolidated investments in power projects .....	(16,552)	(16,225)	(28,796)
Equipment cancellation and asset impairment charge .....	404,737	—	—
Project development expense .....	79,348	35,879	27,556
General and administrative expense .....	235,708	153,836	97,749
Merger expense .....	—	41,627	—
Income from operations .....	313,699	1,018,378	651,260
Interest expense .....	413,720	198,497	81,890
Distributions on trust preferred securities .....	62,632	62,412	45,076
Interest income .....	(43,148)	(72,458)	(40,504)
Other expense (income) .....	(149,501)	(55,049)	544
Income before provision (benefit) for income taxes .....	29,996	884,976	564,254
Provision (benefit) for income taxes .....	(19,096)	298,665	231,451
Income before discontinued operations and cumulative effect of a change in accounting principle .....	49,092	586,311	332,803
Discontinued operations, net of tax provision of \$47,036, \$36,750 and \$31,454 .....	69,526	36,145	36,281
Cumulative effect of a change in accounting principle, net of tax provision of \$699 .....	—	1,036	—
Net income .....	<u>\$ 118,618</u>	<u>\$ 623,492</u>	<u>\$ 369,084</u>
Basic earnings per common share:			
Weighted average shares of common stock outstanding .....	354,822	303,522	281,084
Income before discontinued operations and cumulative effect of a change in accounting principle .....	\$ 0.14	\$ 1.93	\$ 1.18
Discontinued operations, net of tax .....	\$ 0.19	\$ 0.12	\$ 0.13
Cumulative effect of a change in accounting principle .....	\$ —	\$ —	\$ —
Net income .....	<u>\$ 0.33</u>	<u>\$ 2.05</u>	<u>\$ 1.31</u>
Diluted earnings per common share:			
Weighted average shares of common stock outstanding before dilutive effect of certain convertible securities .....	362,533	317,919	297,507
Income before dilutive effect of certain convertible securities, discontinued operations and cumulative effect of a change in accounting principle .....	\$ 0.14	\$ 1.84	\$ 1.12
Dilutive effect of certain convertible securities(2) .....	\$ —	\$ (0.14)	\$ (0.05)
Income before discontinued operations and cumulative effect of a change in accounting principle .....	\$ 0.14	\$ 1.70	\$ 1.07
Discontinued operations, net of tax .....	\$ 0.19	\$ 0.10	\$ 0.11
Cumulative effect of a change in accounting principle .....	\$ —	\$ —	\$ —
Net income .....	<u>\$ 0.33</u>	<u>\$ 1.80</u>	<u>\$ 1.18</u>

(1) See Note 2 to Consolidated Financial Statements regarding the restatement of financial statements.

(2) See Note 25 to Consolidated Financial Statements for further information.

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, 2002, 2001, and 2000**

	Common Stock	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Loss	Total Stockholders' Equity	Comprehensive Income
	(In thousands, except share amounts)					
Balance, January 1, 2000	\$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, restated(1)	—	—	369,084	—	369,084	\$ 369,084
Other comprehensive loss	—	—	—	(6,026)	(6,026)	(6,026)
Total comprehensive income	—	—	—	—	—	\$ 363,058
Balance, December 31, 2000, restated(1)	<u>300</u>	<u>1,896,987</u>	<u>544,377</u>	<u>(25,363)</u>	<u>2,416,301</u>	
Issuance of 6,833,497 shares of common stock, net of issuance costs	7	72,459	—	—	72,466	
Issuance of 151,176 shares of common stock for acquisitions	—	7,500	—	—	7,500	
Tax benefit from stock options exercised and other	—	63,887	—	—	63,887	
Comprehensive income:						
Net income, restated(1)	—	—	623,492	—	623,492	\$ 623,492
Other comprehensive loss	—	—	—	(215,517)	(215,517)	(215,517)
Total comprehensive income	—	—	—	—	—	\$ 407,975
Balance, December 31, 2001, restated(1)	<u>307</u>	<u>2,040,833</u>	<u>1,167,869</u>	<u>(240,880)</u>	<u>2,968,129</u>	
Issuance of 73,757,381 shares of common stock, net of issuance costs	74	751,721	—	—	751,795	
Tax benefit from stock options exercised and other	—	9,949	—	—	9,949	
Comprehensive income:						
Net income	—	—	118,618	—	118,618	\$ 118,618
Other comprehensive income	—	—	—	3,423	3,423	3,423
Total comprehensive income	—	—	—	—	—	\$ 122,041
Balance, December 31, 2002	<u>\$381</u>	<u>\$2,802,503</u>	<u>\$1,286,487</u>	<u>\$(237,457)</u>	<u>\$3,851,914</u>	

(1) See Note 2 to Consolidated Financial Statements regarding the restatement of financial statements.

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, 2002, 2001, and 2000**

	<u>2002</u>	<u>2001</u>	<u>2000</u>
		<u>Restated (1)</u>	<u>Restated (1)</u>
		(In thousands)	
<b>Cash flows from operating activities:</b>			
Net income	\$ 118,618	\$ 623,492	\$ 369,084
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	542,176	364,056	228,384
Equipment cancellation and asset impairment charge	404,737	—	—
Development cost write-off	56,427	—	—
Deferred income taxes, net	23,206	82,410	(8,222)
(Gain) on sale of assets	(97,377)	(38,258)	(1,051)
(Gain) loss on retirement of debt	(118,020)	(9,600)	2,031
Minority interests	2,716	1,345	1,819
Income from unconsolidated investments in power projects	(16,490)	(9,433)	(23,969)
Distributions from unconsolidated investments in power projects	14,117	5,983	29,979
Change in operating assets and liabilities, net of effects of acquisitions:			
Accounts receivable	229,187	(230,400)	(486,968)
Change in net derivative liability	(268,551)	57,693	—
Other current assets	405,515	(527,296)	9,917
Other assets	(306,894)	(120,310)	(58,174)
Accounts payable and accrued expense	(48,804)	449,369	674,935
Other liabilities	200,203	71,927	137,986
Other comprehensive income (loss) relating to derivatives	(72,300)	(297,409)	—
Net cash provided by operating activities	<u>1,068,466</u>	<u>423,569</u>	<u>875,751</u>
<b>Cash flows from investing activities:</b>			
Purchases of property, plant and equipment	(4,036,254)	(5,832,874)	(3,068,528)
Disposals of property, plant and equipment	400,349	49,120	17,321
Acquisitions, net of cash acquired	—	(1,608,840)	(728,455)
Proceeds from sale leasebacks	—	517,081	242,205
Advances to joint ventures	(68,088)	(177,917)	(132,102)
Maturities of collateral securities	3,586	2,549	6,445
Project development costs	(105,182)	(147,520)	(50,912)
Cash flows from derivatives not designated as hedges	26,091	29,145	—
(Increase) decrease in restricted cash	(73,848)	(45,642)	8,374
(Increase) decrease in notes receivable	8,926	(40,273)	(165,509)
Other	6,593	14,516	(6,026)
Net cash used in investing activities	<u>(3,837,827)</u>	<u>(7,240,655)</u>	<u>(3,877,187)</u>
<b>Cash flows from financing activities:</b>			
Proceeds from issuance of Zero-Coupon Convertible Debentures Due 2021	—	1,000,000	—
Repurchase of Zero-Coupon Convertible Debentures Due 2021	(869,736)	(110,100)	—
Borrowings from notes payable and borrowings under lines of credit	1,348,798	148,863	1,100,766
Repayments of notes payable and borrowings under lines of credit	(126,404)	(962,873)	(1,315,506)
Borrowings from project financing	725,111	3,869,391	1,548,328
Repayments of project financing	(286,293)	(1,712,292)	(631,374)
Proceeds from issuance of Convertible Senior Notes Due 2006	100,000	1,100,000	—
Repayments of senior notes	—	(106,300)	—
Proceeds from Company — obligated mandatorily redeemable convertible preferred securities of a subsidiary trust	—	—	877,500
Proceeds from senior debt offerings	—	4,596,039	1,000,000
Proceeds from issuance of common stock	751,795	72,465	784,033
Proceeds from Income Trust Offering	169,677	—	—
Financing costs	(42,783)	(144,746)	(37,750)
Other	(12,769)	(270)	(9,210)
Net cash provided by financing activities	<u>1,757,396</u>	<u>7,750,177</u>	<u>3,316,787</u>
Effect of exchange rate changes on cash and cash equivalents	(2,693)	(3,669)	—
Net increase (decrease) in cash and cash equivalents	(1,014,658)	929,422	315,351
Cash and cash equivalents, beginning of period	1,594,144	664,722	349,371
Cash and cash equivalents, end of period	<u>\$ 579,486</u>	<u>\$ 1,594,144</u>	<u>\$ 664,722</u>
<b>Cash paid during the period for:</b>			
Interest, net of amounts capitalized	\$ 325,334	\$ 42,883	\$ 15,912
Income taxes	\$ 15,451	\$ 114,667	\$ 144,406
<b>Schedule of non cash investing and financing activities:</b>			
— 2002 non-cash consideration of \$88.4 million in tendered Company debt received upon the sale of its British Columbia oil and gas properties			
— 2001 equity investment in a power project for \$17.5 million note receivable			

(1) See Note 2 to Consolidated Financial Statements regarding the restatement of financial statements.

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

**CALPINE CORPORATION AND SUBSIDIARIES**  
**NOTES TO CONSOLIDATED FINANCIAL STATEMENTS**  
**For the Years Ended December 31, 2002, 2001, and 2000**

**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, Canada and the United Kingdom. The Company is involved in the development, construction, 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. In Canada, the Company owns power facilities and oil and gas operations. In the United Kingdom, the Company owns a gas-fired power cogeneration facility. 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 power cogeneration facilities is primarily sold to industrial users. Gas produced and not physically delivered to the Company’s generating plants is sold to third parties.

**2. Restatement of Prior Period Financial Statements**

Subsequent to the issuance of the Company’s 2001 consolidated financial statements, the Company determined that the sale/leaseback transactions for the Pasadena and Broad River facilities should have been accounted for as financing transactions, rather than as sales with operating leases as had been the accounting previously afforded such transactions. In September 2000, the Company completed a leveraged lease financing transaction to provide the term financing for both Phases I and II of the Pasadena, Texas Facility. 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. In October 2001, the Company completed the leveraged lease financing of the Broad River facility. Under the terms of the lease, the Company received \$300.0 million in gross proceeds and recorded a deferred gain of \$1.7 million. Statement of Financial Accounting Standards (“SFAS”) No. 98 “Accounting for Leases,” governs the accounting for sale and leaseback transactions and prohibits sale-leaseback accounting treatment when the leaseback involves a material sublease. At both the Pasadena and Broad River facilities, the Company entered into long-term power sales agreements. Certain of these agreements have been determined to meet the definition of leases within the meaning of SFAS No. 13, and have also been determined to be material subleases. Therefore, sale/leaseback accounting treatment is precluded for those plants. Accordingly, these two sale/leaseback transactions have been restated as financing transactions and the proceeds have been classified as debt and the operating lease payments have been recharacterized as debt service payments in the accompanying consolidated financial statements. The Company is therefore now accounting for the assets as if they had not been sold. The assets have been added back to the Company’s property, plant and equipment, and depreciation has been recorded thereon.

As a result, the Company has restated the accompanying 2001 and 2000 consolidated financial statements from amounts previously reported to properly account for these two transactions as financing transactions and to record certain other adjustments.

In addition, the Company has reclassified certain amounts in the accompanying 2001 and 2000 consolidated financial statements to reflect the adoption of new accounting standards. The reclassifications include (a) treatment as discontinued operations pursuant to SFAS No. 144 “Accounting for the Impairment of Long-Lived Assets and Long-Lived Assets to be Disposed of” of the 2002 sales of certain oil and gas properties and the DePere Energy Center, (b) the reclassification of gains and losses, net associated with extinguishment of debt in 2001 and 2000 from extraordinary item to nonoperating other expense (income) pursuant to SFAS No. 145, “Recission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13 and Technical Corrections,” and (c) the reclassification of revenues and costs associated with certain energy trading contracts to trading revenues, net pursuant to Emerging Issues Task Force

(“EITF”) Issue No. 02-3, “Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities.”

A summary of the significant effects of the restatements along with certain reclassification adjustments is as follows:

	Income Statement as previously reported	Adjustments to reflect adoption of new accounting standards(1)	Adjustments to correct the accounting for two leases(2)	Other adjustments(3)	Income Statement as restated
<b>2001</b>					
Depreciation, depletion and amortization expense . . . . .	\$338,244	\$(41,466)	\$ 10,506	\$ 4,018	\$311,302
Operating lease expense . . . . .	\$118,873	\$ —	\$(18,352)	\$(1,002)	\$ 99,519
Interest expense . . . . .	\$165,360	\$( 7,529)	\$ 38,510	\$ 2,156	\$198,497
Income before extraordinary gain (charge) and cumulative effect of a change in accounting principle . . . . .	\$641,062	\$(30,138)	\$(19,164)	\$(5,449)	\$586,311
Net income . . . . .	\$648,105	\$ —	\$(19,164)	\$(5,449)	\$623,492
Diluted earnings per common share . . . . .	1.87				1.80
<b>2000</b>					
Depreciation, depletion and amortization expense . . . . .	\$230,787	\$(37,817)	\$ 2,935	\$ (42)	\$195,863
Operating lease expense . . . . .	\$ 69,419	\$ —	\$( 4,955)	\$(1,001)	\$ 63,463
Interest expense . . . . .	\$ 74,683	\$( 4,699)	\$ 11,315	\$ 591	\$ 81,890
Income before extraordinary gain (charge) and cumulative effect of a change in accounting principle . . . . .	\$373,837	\$(37,516)	\$( 5,810)	\$ 2,292	\$332,803
Net income . . . . .	\$372,602	\$ —	\$( 5,810)	\$ 2,292	\$369,084
Diluted earnings per common share . . . . .	1.19				1.18
	Balance Sheet as previously reported	Adjustments to reflect adoption of new accounting standards(1)	Adjustments to correct the accounting for two leases(2)	Other adjustments(3)	Balance Sheet as restated
<b>2001</b>					
Property, plant and equipment, net . . . .	\$15,384,990	\$(439,223)	\$618,304	\$(236,677)	\$15,327,394
Total assets . . . . .	\$21,309,295	\$ —	\$595,667	\$ 32,265	\$21,937,227
Construction/project financing, net of current portion . . . . .	\$ 3,393,410	\$ —	\$687,085	\$ —	\$ 4,080,495
Deferred revenue . . . . .	\$ 154,381	\$ —	\$(61,554)	\$( 688)	\$ 92,139
Total liabilities . . . . .	\$17,128,313	\$ —	\$620,641	\$ 51,678	\$17,800,632
Total stockholders' equity . . . . .	\$ 3,010,569	\$ —	\$(24,974)	\$( 17,466)	\$ 2,968,129

- (1) Includes the effect of adopting SFAS No. 144, SFAS No. 145 and EITF Issue No. 02-3
- (2) Includes the effect of restating the accounting for the Pasadena and Broad River sale/leaseback transactions from operating lease accounting to financing transactions
- (3) Includes the effect of certain other adjustments and the effect of reclassification entries made to conform certain prior period amounts to the 2002 presentation

*Reclassification of Prior Period Financial Information related to newly issued Accounting Standards* — In 2002, the Company sold certain gas assets, as well as the DePere Energy Center. The decision to sell these

assets required the application of one of the newly issued accounting standards, SFAS No. 144, which changed the criteria for determining when the disposal or sale of certain assets meets the definition of "discontinued operations." Some of our asset sales in 2002 met the requirements of the new definition and accordingly, the Company made reclassifications to current and prior period financial statements to reflect the sale or designation as "held for sale" of certain oil and gas and power plant assets and liabilities and to separately classify the operating results of the assets sold and gain on sale of those assets from the operating results of continuing operations. See Note 12 for further information.

In April 2002, the FASB issued SFAS No. 145. SFAS No. 145 rescinds SFAS No. 4, "Reporting Gains and Losses from Extinguishment of Debt." The Company elected early adoption, effective July 1, 2002, of the provisions related to the rescission of SFAS No. 4. In December 2001, the Company had recorded an extraordinary gain of \$7.4 million, net of tax of \$4.5 million, related to the repurchase of \$122.0 million Zero Coupons. The extraordinary gain was offset by an extraordinary loss of \$1.4 million, net of tax of \$0.9 million, related to the write-off of unamortized deferred financing costs in connection with the repayment of \$105 million of the 9¼% Senior Notes Due 2004 and the bridge facilities. In August 2000, in connection with repayment of outstanding borrowings, the termination of certain credit agreements and the related write-off of deferred financing costs, the Company recorded an extraordinary loss of \$1.2 million, net of tax of \$0.8 million.

In October 2002, the EITF discussed EITF Issue No. 02-3. The EITF reached a consensus to rescind EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities," the impact of which is to preclude mark-to-market accounting for all energy trading contracts not within the scope of SFAS No. 133. The EITF also reached a consensus that gains and losses on derivative instruments within the scope of SFAS No. 133 should be shown net in the income statement if the derivative instruments are held for trading purposes, as defined in SFAS No. 115, "Accounting for Certain Investments in Debt and Equity Securities." EITF Issue No. 02-3 has had no impact on the Company's net income but has affected the presentation of the Consolidated Financial Statements. Effective July 1, 2002, the Company changed its method of reporting trading revenues to conform to this standard and accordingly, the Company reclassified certain revenue amounts and cost of revenue in its Consolidated Statements of Operations as follows (in thousands):

	For the Years Ended December 31,	
	2002	2001
Amounts previously classified as:		
Sales of purchased power .....	\$845,349	\$732,193
Sales of purchased gas .....	126,031	23,441
Purchased power expense .....	833,174	722,267
Purchased gas expense .....	121,944	23,827
Cost of oil and natural gas burned by power plants (fuel expense) .....	<u>(9,828)</u>	<u>(19,605)</u>
Net amount reclassified to:		
Realized revenue on power and gas trading transactions, net .....	<u>\$ 26,090</u>	<u>\$ 29,145</u>
Amounts previously classified as:		
Electric power derivative mark-to-market gain (loss) .....	8,017	98,291
Natural gas derivative mark-to-market gain (loss) .....	<u>(12,622)</u>	<u>24,302</u>
Net amount reclassified to:		
Unrealized mark-to-market gain (loss) on power and gas trading transactions, net .....	<u>\$ (4,605)</u>	<u>\$122,593</u>

The reclassification of the financial information in accordance with SFAS No. 144, SFAS No. 145 and EITF Issue No. 02-3 discussed above relates exclusively to the presentation and classification of such amounts and has no effect on net income.

*Restatement of Certain Other Prior Period Financial Information* — The Company restated certain other prior period amounts. These adjustments did not have a significant effect on the Company's 2001 and 2000 financial statements.

*Reclassifications* — Certain prior years' amounts in the Consolidated Financial Statements have been reclassified to conform to the 2002 presentation.

### 3. Summary of Significant Accounting Policies

*Principles of Consolidation* — The accompanying consolidated financial statements include accounts of the Company and its wholly owned and majority-owned subsidiaries. Certain less-than-majority-owned subsidiaries are accounted for using the equity method. 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 9). All intercompany accounts and transactions are eliminated in consolidation.

On April 19, 2001, Calpine acquired 100% of the outstanding shares and interests of Encal Energy Ltd. ("Encal"). 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 merger was accounted for as a pooling-of-interests, and the consolidated financial statements have been prepared to give retroactive effect to the merger.

Encal operated under the same fiscal year end as Calpine, and accordingly, Encal's statements of operations, shareholders' equity and cash flows for the fiscal year ended December 31, 2000, have been combined with the Company's consolidated financial statements. The results of operations previously reported by the separate companies and the combined amounts presented in the consolidated financial statements are summarized below.

	<u>Year Ended December 31,</u> <u>2000</u> <u>(In thousands)</u>
Revenues:	
Calpine .....	\$2,110,870
Encal .....	<u>264,308</u>
Combined revenues .....	<u><u>\$2,375,178</u></u>
Net Income:	
Calpine .....	\$ 319,934
Encal .....	<u>49,150</u>
Combined net income .....	<u><u>\$ 369,084</u></u>

*Use of Estimates in Preparation of Financial Statements* — The preparation of financial statements in conformity with generally accepted accounting principles in the United States of America requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of 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 useful lives and carrying values of assets (including the carrying value of projects in development, construction and operation), provision for income taxes, fair value calculations of derivative instruments and associated reserves, capitalization of interest 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 18 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.

The Company has certain project debt agreements which establish working capital accounts which limit the use of certain cash balances to the operations of the respective plants. At December 31, 2002 and 2001, \$189.0 million and \$336.6 million, respectively of the cash and cash equivalents balance was subject to such project debt agreements.

*Accounts Receivable and Accounts Payable* — Accounts receivable and payable represent amounts due from customers and owed to vendors. These balances also include settled but unpaid amounts relating to hedging, balancing, optimization and trading activities of Calpine Energy Services, L.P. (“CES”). Some of these receivables and payables with individual counterparties are subject to master netting agreements whereby the Company legally has a right of offset and the Company settles the balances net. However, for balance sheet presentation purposes and to be consistent with the way the Company is required to present amounts related to hedging, balancing and optimization activities in its statements of operations under Staff Accounting Bulletin (“SAB”) No. 101 “Revenue Recognition in Financial Statements” and EITF Issue No. 99-19 “Reporting Revenue Gross as a Principal Versus Net as an Agent”, the Company presents its receivables and payables on a gross basis.

*Inventories* — The Company’s inventories primarily include spare parts and stored gas. 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. Stored gas is valued at the lower of weighted average cost or market.

*Margin Deposits* — As of December 31, 2002 and 2001, in order to satisfy the credit requirements of trading counterparties, CES had deposited net amounts of \$25.2 million and \$345.5 million, respectively, in cash as margin deposits.

*Collateral Debt Securities* — The Company classifies all short-term and long-term debt securities as held-to-maturity because the Company has the intent and ability to hold the securities to maturity. The securities act as collateral to support the King City operating lease and mature serially in amounts equal to a portion of the semi-annual lease payments. Held-to-maturity securities are stated at amortized cost, adjusted for amortization of premiums and accretion discounts to maturity. The Company owns no investments that are considered to be available-for-sale or trading securities.

*Property, Plant and Equipment, Net* — See Note 5 for a discussion of the Company’s accounting policies for its property, plant and equipment.

*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. Upon commencement of construction, these costs are transferred to construction in progress, a component of property, plant and equipment. Upon the start-up of plant operations, these construction costs are reclassified as buildings, machinery and equipment, also a component of property, plant and equipment, and are amortized as a component of the total cost of the plant over its estimated useful life. Capitalized project costs are charged to expense if the Company determines that the project is no longer probable or to the extent it is impaired. Outside services and other third party costs are capitalized for acquisition projects.

*Investments in Power Projects* — The Company uses the equity method to recognize its pro rata share of the net income or loss of an unconsolidated investment until such time, if applicable, that 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.

*Restricted Cash* — The Company is required to maintain cash balances that are restricted by provisions of its debt agreements, lease agreements and regulatory agencies. These amounts are held by depository banks in order to comply with the contractual provisions requiring reserves for payments such as for debt service, rent service, and major maintenance. Funds that will be used to satisfy obligations due during the next twelve months are classified as current restricted cash, with the remainder classified as non-current restricted cash. 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 in the consolidated statement of cash flows.

*Notes Receivable* — See Note 10 for a discussion of the Company's accounting policies for its notes receivable.

*Deferred Financing Costs* — The deferred financing costs related to the Company's Senior Notes and the Convertible Senior Notes Due 2006 are amortized over the life of the related debt, ranging from 5 to 10 years, using the straight-line method which approximates the effective interest rate method (See Note 17). 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, which approximates the effective interest rate method (See Note 16). The deferred financing costs related to the Zero-Coupon Debentures Due 2021 were amortized over 1 year due to the put option that was exercised by the holders in 2002. Costs incurred in connection with obtaining other financing are deferred and amortized over the life of the related debt.

*Long-Lived Assets* — In accordance with Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standards ("SFAS") No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets and for Long-Lived Assets to be Disposed of," the Company evaluates the impairment of long-lived assets, based on the projection of undiscounted pre-interest expense and pre-tax expense 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 (See Note 5).

*Concentrations of Credit Risk* — Financial instruments which potentially subject the Company to concentrations of credit risk consist primarily of cash, accounts receivable, notes receivable, and commodity contracts. 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 10 and 23). The Company generally does not require collateral for accounts receivable from end-user customers, but evaluates the net accounts receivable, accounts payable, and fair value of commodity contracts with trading companies and may require security deposits or letters of credit to be posted if exposure reaches a certain level.

*Deferred Revenue* — The Company's deferred revenue consists primarily of deferred gains for the sale/leaseback transactions as well as deferred revenue for long-term power supply contracts. See Note 8 and 23.

*Trust Preferred Securities* — The Company's trust preferred securities are accounted for 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 in the statements of operations as "distributions on trust preferred securities." Financing costs related to these issuances are netted with the principal amounts and are accreted as minority interest expense over the securities' 30-year maturity using the straight-line method which approximates the effective interest rate method (See Note 19).

*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 the Company's cogeneration sites. In addition, the Company acquires and produces natural gas for its own consumption and

sells the balance and oil produced to third parties. Where applicable, revenues are recognized under EITF No. 91-6, "Revenue Recognition of Long Term Power Sales Contracts," ratably over the terms of the related contracts. To protect and enhance the profit potential of its electric generation plants, the Company, through its subsidiary, CES, enters into electric and gas hedging, balancing, and optimization transactions, subject to market conditions, and CES has also, from time to time, entered into contracts considered energy trading contracts under EITF Issue No. 02-3. CES executes these transactions primarily through the use of physical forward commodity purchases and sales and financial commodity swaps and options. With respect to its physical forward contracts, CES generally acts as a principal, takes title to the commodities, and assumes the risks and rewards of ownership. Therefore, when CES does not hold these contracts for trading purposes and, in accordance with SAB No. 101, and EITF Issue No. 99-19, the Company records settlement of its non-trading physical forward contracts on a gross basis. Effective July 1, 2002, the Company changed its method of reporting gains and losses from derivatives held for trading purposes to a net basis. Prior to July 1, 2002, physical trading contracts were recorded on a gross basis but have been reclassified to a net basis to conform to the current presentation. The Company settles its financial swap and option transactions net and does not take title to the underlying commodity. Accordingly, the Company records gains and losses from settlement of financial swaps and options net within net income. Managed risks typically include commodity price risk associated with fuel purchases and power sales.

The Company, through its wholly owned subsidiary, Power Systems Mfg., LLC ("PSM"), designs and manufactures certain spare parts for gas turbines. The Company also generates revenue by occasionally loaning funds to power projects, by providing operation and maintenance ("O&M") services to third parties and to certain unconsolidated power projects, and by performing engineering services for data centers and other facilities requiring highly reliable power. The Company also has begun to sell engineering and construction services to third parties for power projects. 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 and sales of purchased power for hedging, balancing and optimization. Subject to market and other conditions, the Company manages the revenue stream for its portfolio of electric generating facilities. 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, through hedging, balancing and optimization transactions. CES performs a market-based allocation of total electric generation and marketing revenue to electricity and steam sales (based on electricity delivered by the Company's electric generating facilities) and the balance is allocated to sales of purchased power.

*Oil and Gas Production and Marketing Revenue* — This includes sales to third parties of oil, gas and related products that are produced by the Company's Calpine Natural Gas and Calpine Canada Natural Gas subsidiaries and, subject to market and other conditions, sales of purchased gas arising from hedging, balancing and optimization transactions. Oil and gas sales for produced products are recognized pursuant to the sales method, net of royalties. If the Company has recorded gas sales on a particular well or field in excess of its share of remaining estimated reserves, then the excessive gas sale imbalance is recognized as a liability. If the Company is under-produced on a particular well or field, and it is determined that an over-produced partner's share of remaining reserves is insufficient to settle the gas imbalance, the Company will recognize a receivable, to the extent collectible, from the over-produced partner.

*Trading Revenue, Net* — This includes realized settlements of and unrealized mark-to-market gains and losses on both power and gas derivative instruments held for trading purposes. Gains and losses due to ineffectiveness on hedging instruments are also included in unrealized mark-to-market gains and losses.

*Other Revenue* — This includes O&M contract revenue, PSM revenue from sales to third parties, engineering revenue and miscellaneous revenue.

*Purchased Power and Purchased Gas Expense* — The cost of power purchased from third parties for hedging, balancing and optimization activities is recorded as purchased power expense, a component of electric generation and marketing expense. The Company records the cost of gas purchased from third parties for the purposes of consumption in its power plants as fuel expense, while gas purchased from third parties for

hedging, balancing, and optimization activities is recorded as purchased gas expense, a component of oil and gas production and marketing expense.

*Insurance Program* — The CPN Insurance Corporation, a wholly owned captive insurance subsidiary, charges the Company competitive premium rates to insure workers' compensation, automobile liability, general liability as well as all risk property insurance including business interruption. Accruals for claims under the captive insurance program pertaining to property, including business interruption claims, are recorded on a claims-incurred basis. Accruals for casualty claims under the captive insurance program are recorded on a monthly basis, and are based upon the estimate of the total cost of claims incurred during the policy period. The captive insures limits up to \$25 million per occurrence for property claims, including business interruption, and up to \$500,000 per occurrence for casualty claims.

*Derivative Instruments* — SFAS No. 133, "Accounting for Derivative Instruments and Hedging Activities" as amended and interpreted by other related accounting literature, establishes accounting and reporting standards for derivative instruments (including certain derivative instruments embedded in other contracts). SFAS No. 133 requires companies to record derivatives on their balance sheets as either assets or liabilities measured at their fair value unless exempted from derivative treatment as a normal purchase and sale. All changes in the fair value of derivatives are recognized currently in earnings unless specific hedge criteria are met, which requires that a company must formally document, designate, and assess the effectiveness of transactions that receive hedge accounting.

SFAS No. 133 sets forth the accounting requirements for cash flow and fair value hedges. SFAS No. 133 provides that the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument be reported as a component of other comprehensive income and be reclassified into earnings in the same period during which the hedged forecasted transaction affects earnings. The remaining gain or loss on the derivative instrument, if any, must be recognized currently in earnings. SFAS No. 133 provides that the changes in fair value of derivatives designated as fair value hedges and the corresponding changes in the fair value of the hedged risk attributable to a recognized asset, liability, or unrecognized firm commitment be recorded in earnings. If the fair value hedge is effective, the amounts recorded will offset in earnings.

Where the Company's derivative instruments are subject to a master netting agreement and the criteria of FASB Interpretation ("FIN") 39 "Offsetting of Amounts Related to Certain Contracts (An Interpretation of APB Opinion No. 10 and SFAS No. 105) are met, the Company presents its derivative assets and liabilities on a net basis in its balance sheet. The Company has chosen this method of presentation because it is consistent with the way related mark-to-market gains and losses on derivatives are recorded in its Consolidated Statements of Operations and within Other Comprehensive Income ("OCI").

#### *New Accounting Pronouncements*

In July 2001, the Company adopted SFAS No. 141, "Business Combinations," which supersedes Accounting Principles Board ("APB") Opinion No. 16, "Business Combinations" and SFAS No. 38, "Accounting for Preacquisition Contingencies of Purchased Enterprises." SFAS No. 141 eliminated the pooling-of-interests method of accounting for business combinations and modified the recognition of intangible assets and disclosure requirements. The adoption of SFAS No. 141 did not have a material effect on the Company's consolidated financial statements.

On January 1, 2002, the Company adopted SFAS No. 142, "Goodwill and Other Intangible Assets," which supersedes APB Opinion No. 17, "Intangible Assets." See Note 6 for further information.

In June 2001, the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations". SFAS No. 143 applies to fiscal years beginning after June 15, 2002 and amends SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies." This standard applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development or normal use of the assets and requires that a liability for an asset retirement obligation be recognized when incurred, recorded at fair value and classified as a liability in the balance sheet. When the liability is initially

recorded, the entity will capitalize the cost and increase the carrying value of the related long-lived asset. Asset retirement obligations represent future liabilities, and, as a result, accretion expense will be accrued on this liability until the obligation is satisfied. At the same time, the capitalized cost will be depreciated over the estimated useful life of the related asset. At the settlement date, the entity will settle the obligation for its recorded amount or recognize a gain or loss upon settlement.

The Company adopted the new rules on asset retirement obligations on January 1, 2003. As required by the new rules, we recorded liabilities equal to the present value of expected future asset retirement obligations at January 1, 2003. The Company identified obligations related to operating gas-fired power plants, geothermal power plants and oil and gas properties. The liabilities are partially offset by increases in net assets, net of accumulated depreciation, recorded as if the provisions of the Statement had been in effect at the date the obligation was incurred, which is generally the start of commercial operations for the facility.

Based on current information and assumptions the Company expects to record an additional long-term liability of \$33.3 million, an additional asset within Property, Plant and Equipment, net of accumulated depreciation, of \$33.7 million, and a gain to income due to the cumulative effect of a change in accounting principle of (\$0.4) million, net of taxes. These entries include the effects of the reversal of site dismantlement and restoration costs previously expensed in accordance with SFAS No. 19. Due to the complexity of this accounting standard and the number of assumptions used in the calculations, the Company may make adjustments to these estimates prior to the filing of Form 10-Q for the quarter ending March 31, 2003.

On January 1, 2002, the Company adopted SFAS No. 144, which supersedes SFAS No. 121, "Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of," and the accounting and reporting provisions of APB Opinion No. 30, "Reporting the Results of Operations — Reporting the Effects of Disposal of a Segment of a Business, and Extraordinary, Unusual and Infrequently Occurring Events and Transactions," for the disposal of a segment of a business (as previously defined in that APB Opinion). SFAS No. 144 establishes a single accounting model, based on the framework established in SFAS No. 121, for long-lived assets to be disposed of by sale. SFAS No. 144 also resolves several significant implementation issues related to SFAS No. 121, such as eliminating the requirement to allocate goodwill to long-lived assets to be tested for impairment and establishing criteria to define whether a long-lived asset is held for sale. Adoption of SFAS No. 144 has not had a material net effect on the Company's consolidated financial statements, although certain reclassifications have been made to current and prior period financial statements to reflect the sale or designation as "held for sale" of certain oil and gas and power plant assets and classification of the operating results. In general, gains from completed sales and any anticipated losses on "held for sale" assets are included in discontinued operations net of tax. See Note 12 for further information.

In April 2002, the FASB issued SFAS No. 145, SFAS No. 145 rescinds SFAS No. 4, "Reporting Gains and Losses from Extinguishment of Debt" and an amendment of that statement, SFAS No. 64, "Extinguishments of Debt Made to Satisfy Sinking-Fund Requirements" and provides that gains or losses from extinguishment of debt that fall outside of the scope of APB Opinion No. 30 should not be classified as extraordinary. SFAS No. 145 also amends SFAS No. 13, "Accounting for Leases," to eliminate an inconsistency between the required accounting for sale/leaseback transactions and the required accounting for certain lease modifications that have economic effects that are similar to sale/leaseback transactions. SFAS No. 145 also amends other existing authoritative pronouncements to make various technical corrections, clarify meanings, or describe their applicability under changed conditions. The Company elected early adoption, effective July 1, 2002, of the provisions related to the rescission of SFAS No. 4, the effect of which has been reflected in these financial statements as reclassifications of gains and losses from the extinguishment of debt from extraordinary gain/(loss) to other (income)/expense totaling \$118.0 million in 2002, \$9.6 million in 2001 and \$(2.0) million in 2000. The provisions related to SFAS No. 13 are effective for transactions occurring after May 15, 2002. All other provisions are effective for financial statements issued on or after May 15, 2002, with early adoption encouraged. The Company believes that the SFAS No. 145 provisions relating to leases will not have a material effect on its financial statements.

In June 2002, the FASB issued SFAS No. 146, "Accounting for Costs Associated with Exit or Disposal Activities," which addresses accounting for restructuring and similar costs. SFAS No. 146 supersedes previous

accounting guidance, principally EITF Issue No. 94-3, "Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (Including Certain Costs Incurred in a Restructuring)." The Company will adopt the provisions of SFAS No. 146 for restructuring activities initiated after December 31, 2002. SFAS No. 146 requires that the liability for costs associated with an exit or disposal activity be recognized when the liability is incurred. Under EITF No. 94-3, a liability for an exit cost was recognized at the date of commitment to an exit plan. SFAS No. 146 also establishes that the liability should initially be measured and recorded at fair value. Accordingly, SFAS No. 146 may affect the timing of recognizing future restructuring costs as well as the amounts recognized. The Company does not believe that SFAS No. 146 will have a material effect on its Consolidated Financial Statements other than timing of exit costs.

In October 2002 the EITF discussed EITF Issue No. 02-3. See Note 2 for further information on EITF Issue No. 02-3 and its impact on the Consolidated Financial Statements.

In November 2002, the FASB issued FIN 45, "Guarantor's Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others". FIN 45 expands on the accounting guidance of SFAS No. 5, "Accounting for Contingencies," SFAS No. 57, "Related Party Disclosures," and SFAS No. 107, "Disclosures about Fair Value of Financial Instruments." FIN 45 also incorporates, without change, the provisions of FASB Interpretation No. 34, "Disclosures of Indirect Guarantees of the Indebtedness of Others," which it supersedes. FIN 45 elaborates on the existing disclosure requirements for most guarantees. It clarifies that a guarantor's required disclosures include the nature of the guarantee, the maximum potential undiscounted payments that could be required, the current carrying amount of the liability, if any, for the guarantor's obligations (including the liability recognized under SFAS No. 5), and the nature of any recourse provisions or available collateral that would enable the guarantor to recover amounts paid under the guarantee. FIN 45 also clarifies that at the time a company issues a guarantee, it must recognize an initial liability for the fair value of the obligation it assumes under that guarantee, including its ongoing obligation to stand ready to perform over the term of the guarantee in the event that specified triggering events or conditions occur. FIN 45 does not prescribe a specific account for the guarantor's offsetting entry when it recognizes the liability at the inception of the guarantee, noting that the offsetting entry would depend on the circumstances in which the guarantee was issued. There also is no prescribed approach included for subsequently measuring the guarantor's recognized liability over the term of the related guarantee. It is noted that the liability would typically be reduced by a credit to earnings as the guarantor is released from risk under the guarantee. The initial recognition and initial measurement provisions apply on a prospective basis to guarantees issued or modified after December 31, 2002. The Company is currently evaluating the impact of FIN 45's initial recognition and measurement provisions on its Consolidated Financial Statements. The disclosure requirements for FIN 45 are effective for financial statements of interim or annual periods ending after December 15, 2002, and have been incorporated into the Company's December 31, 2002, disclosures of guarantees. See (Note 26).

In December 2002, the FASB issued SFAS No. 148, "Accounting for Stock-Based Compensation — Transition and Disclosure." This Statement amends SFAS No. 123, "Accounting for Stock-Based Compensation," to provide alternative methods of transition for a voluntary change to the fair value based method of accounting for stock-based employee compensation. In addition, SFAS No. 148 amends the disclosure requirements of SFAS No. 123 to require prominent disclosures in both annual and interim financial statements about the method of accounting for stock-based employee compensation and the effect of the method used on reported results. The Company anticipates that the adoption of SFAS No. 123 prospectively effective January 1, 2003 will have a material effect on its financial statements. Had stock-based compensation cost for 2002, 2001 and 2000 been accounted for under SFAS No. 123, 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):

	<u>2002</u>	<u>2001</u>	<u>2000</u>
Net income			
As reported .....	\$118,618	\$623,492	\$369,084
Pro Forma .....	83,025	588,442	342,433
Earnings per share data:			
Basic earnings per share			
As reported .....	\$ 0.33	\$ 2.05	\$ 1.31
Pro Forma .....	0.23	1.94	1.22
Diluted earnings per share			
As reported .....	\$ 0.33	\$ 1.80	\$ 1.18
Pro Forma .....	0.23	1.71	1.10
Stock-based compensation cost included in net income, as reported .....	\$ —	\$ —	\$ —
Stock-based compensation cost included in net income, pro forma .....	35,593	35,050	26,651

The range of fair values of the Company's stock options granted in 2002, 2001, and 2000 were as follows, based on varying historical stock option exercise patterns by different levels of Calpine employees: \$3.73-\$6.62 in 2002, \$18.29-\$30.73 in 2001, and \$8.01-\$12.13 in 2000 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 70%-83% for 2002, 55%-59% for 2001, and 49%-50% for 2000, risk-free interest rates of 2.39%-3.83% for 2002, 3.99%-5.07% for 2001, and 4.99%-5.12% for 2000, and expected option terms of 4-9 years for 2002, 2001, and 2000.

The volatility figures and expected option terms shown above have been recalculated for all prior periods based on generally longer historical time frames to be consistent with the Company's upcoming adoption and application of SFAS No. 123. The recalculated assumptions have caused stock-based compensation cost under SFAS No. 123 to be higher than previously reported.

In January 2003 the FASB issued FIN 46, "Consolidation of Variable Interest Entities — an Interpretation of ARB No. 51". FIN 46 establishes accounting reporting and disclosure requirements for companies that currently hold unconsolidated investments in Variable Interest Entities ("VIEs"). FIN 46 defines VIEs as entities that meet one or both of two criteria: 1. The entity's total equity at risk is deemed to be insufficient to finance its ongoing business activities without additional subordinated financial support from other parties. 2. As a collective group, the entity's owners do not have a controlling financial interest in the entity. This effectively occurs if the voting rights to, or the entitlement to future returns or risk of future losses from the investment for each of the entity's owners is inconsistent with the ownership percentages assigned to each owner within the underlying partnership agreement. If an investment is determined to be a VIE, further analysis must be performed to determine which of the VIE's owners qualifies as the primary beneficiary. The primary beneficiary is the owner of the VIE that is entitled or at risk to earn or absorb the majority of the entity's expected future returns or losses. An owner that is determined to be the primary beneficiary of a VIE is required to consolidate the VIE into its financial statements, as well as to provide certain disclosures regarding the size and nature of the VIE, the purpose for the investment, and information about the assets being held as collateral on behalf of the VIE. Additionally, the remaining owners of a VIE that do not qualify as the primary beneficiary must determine whether or not they hold significant variable interests within the VIE. An owner with a significant variable interest in a VIE that is not the primary beneficiary is not required to consolidate the VIE but must provide certain disclosures regarding the size and nature of the VIE, the purpose for the investment, its potential exposure to the VIE's losses, and the date it first acquired ownership in the VIE. FIN 46 applies immediately to VIEs created or acquired after January 31, 2003. It applies in the

first fiscal year or interim period beginning after June 15, 2003, to VIEs that were previously created or acquired before February 1, 2003. The Company has not completed its assessment of the impact of FIN 46.

In connection with the January 2003 EITF meeting, the FASB was asked to clarify the application of SFAS No. 133 Implementation Issue No. C11 "Interpretation of *Clearly and Closely Related* In Contracts That Qualify for the Normal Purchases and Normal Sales Exception" ("C11"). The specific issue relates to pricing based on broad market indices such as the Consumer Price Index ("CPI") and under what circumstances those broad market indices would preclude the normal purchase and sales exception under SFAS No. 133. The Company is currently evaluating how further discussions regarding C11 would impact contracts that have been documented as exempt from derivative treatment as normal purchases and sales. While the Company is still evaluating the impact that this potential new guidance would have on its results of operations and financial position, it believes it could result in additional volatility in reported earnings, other comprehensive income and accumulated other comprehensive income.

#### 4. Investment in Debt Securities

The Company classifies all short-term and long-term debt securities as held-to-maturity because of the intent and ability to hold the securities to maturity. The securities are pledged as collateral to support the King City operating lease and mature serially in amounts equal to a portion of the semi-annual lease payments. The following short-term debt securities are included in Other Current Assets at December 31, 2002 and 2001:

	2002				2001			
	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(In thousands)							
Corporate Debt Securities . . . . .	\$2,012	\$ 38	\$—	\$2,050	\$1,882	\$ 6	\$—	\$1,888
Government Agency Debt Securities . . . . .	1,959	9	—	1,968	1,825	11	—	1,836
U.S. Treasury Securities (non-interest bearing) . . . . .	<u>3,960</u>	<u>81</u>	<u>—</u>	<u>4,041</u>	<u>3,077</u>	<u>56</u>	<u>—</u>	<u>3,133</u>
Debt Securities . . . . .	<u>\$7,931</u>	<u>\$128</u>	<u>\$—</u>	<u>\$8,059</u>	<u>\$6,784</u>	<u>\$73</u>	<u>\$—</u>	<u>\$6,857</u>

The following long-term debt securities are included in Other Assets at December 31, 2002 and 2001:

	2002				2001			
	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value	Amortized Cost	Gross Unrealized Gains	Gross Unrealized Losses	Fair Value
	(In thousands)							
Corporate Debt Securities . . . . .	\$13,968	\$ 939	\$—	\$14,907	\$16,025	\$ 838	\$—	\$16,863
Government Agency Debt Securities . . . . .			—		1,964	90	—	2,054
U.S. Treasury Notes . . . . .	1,972	237	—	2,209	1,972	167	—	2,139
U.S. Treasury Securities (non-interest bearing) . . . . .	<u>62,224</u>	<u>17,068</u>	<u>—</u>	<u>79,292</u>	<u>61,792</u>	<u>9,023</u>	<u>—</u>	<u>70,815</u>
Debt Securities . . . . .	<u>\$78,164</u>	<u>\$18,244</u>	<u>\$—</u>	<u>\$96,408</u>	<u>\$81,753</u>	<u>\$10,118</u>	<u>\$—</u>	<u>\$91,871</u>

The contractual maturities of debt securities at December 31, 2002, are shown below. Actual maturities may differ from contractual maturities because borrowers may have the right to call or prepay obligations with or without call or prepayment penalties.

	<u>Amortized Cost</u>	<u>Fair Value</u>
	(In thousands)	
Due within one year .....	\$ 7,931	\$ 8,059
Due after one year through five years .....	30,436	34,206
Due after five years through ten years .....	26,947	34,127
Due after ten years .....	<u>20,781</u>	<u>28,075</u>
Total debt securities .....	<u>\$86,095</u>	<u>\$104,467</u>

## 5. Property, Plant and Equipment, Net, and Capitalized Interest

As of December 31, 2002 and 2001, the components of property, plant and equipment, are stated at cost less accumulated depreciation and depletion as follows (in thousands):

	<u>2002</u>	<u>2001</u>
Buildings, machinery, and equipment .....	\$10,290,931	\$ 5,321,339
Oil and gas properties, including pipelines .....	2,031,026	1,888,777
Geothermal properties .....	402,643	378,838
Other .....	<u>183,742</u>	<u>119,752</u>
	12,908,342	7,708,706
Less: accumulated depreciation and depletion .....	<u>(1,220,425)</u>	<u>(745,368)</u>
	11,687,917	6,963,338
Land .....	82,158	80,506
Construction in progress .....	<u>7,080,892</u>	<u>8,283,550</u>
Property, plant and equipment, net .....	<u>\$18,850,967</u>	<u>\$15,327,394</u>

Total depreciation and depletion expense for the years ended December 31, 2002, 2001 and 2000 was \$459.4 million, \$298.4 million and \$177.2 million, respectively.

*Buildings, Machinery, and Equipment* — This component includes electric power plants and related equipment. Depreciation is recorded utilizing the straight-line method over the estimated original composite useful life, generally 35 years for power plants, exclusive of the estimated salvage value, typically 10%. Peaking facilities are generally depreciated over 40 years, less the estimated salvage value of 10%. The Company capitalizes the costs for major gas turbine generator refurbishment and amortizes them over their estimated useful lives of generally 3 to 6 years. Additionally, the Company expenses annual planned maintenance.

*Oil and gas properties* — The Company follows the successful efforts method of accounting for oil and natural gas activities. Under the successful efforts method, lease acquisition costs and all development costs are capitalized. Proved oil and gas properties are reviewed for potential impairment when circumstances suggest the need for such a review and, if required, the proved properties are written down to their estimated fair value. Unproved properties are reviewed quarterly to determine if there has been impairment of the carrying value, with any such impairment charged to expense in the period. Exploratory drilling costs are capitalized until the results are determined. If proved reserves are not discovered, the exploratory drilling costs are expensed. Other exploratory costs are expensed as incurred. Interest costs related to financing major oil and gas projects in progress are capitalized until the projects are evaluated or until the projects are substantially complete and ready for their intended use if the projects are evaluated as successful. The provision for depreciation, depletion, and amortization is based on the capitalized costs as determined above, plus future abandonment costs net of salvage value, using the units of production method with lease

acquisition costs amortized over total proved reserves and other costs amortized over proved developed reserves.

*Geothermal Properties* — 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 at such time as management determines that it is probable the property will be developed on an economically viable basis and that costs will be recovered from operations. 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 unit-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. Geothermal steam turbine generator refurbishments are expensed as incurred.

*Construction in Progress* — Construction in progress is primarily attributable to gas-fired power projects under construction including prepayments on gas and steam turbine generators and other long lead-time items of equipment for certain development projects not yet in construction. Upon commencement of plant operation, these costs are transferred to the applicable property category, generally buildings, machinery and equipment.

As of December 31, 2002, the Company has classified \$142.4 million of equipment costs as other assets, as the equipment is not required for the Company's current power plant development program. During the year, the Company has recorded a \$404.7 million charge to equipment cancellation and impairment charges to effect a reduction in the carrying value of such equipment. The Company currently anticipates that some of this equipment will be used for future power plants and some may be sold to third parties. The Company restructured contracts for certain of its remaining gas turbines and steam turbines in the fourth quarter of 2002 (See Note 26). The Company may also, subject to market conditions, take steps to further adjust or restructure turbine orders, including canceling additional turbine orders, consistent with the Company's power plant construction and development programs.

*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)." The Company's qualifying assets include construction in progress, certain oil and gas properties under development, construction costs related to unconsolidated investments in power projects under construction, and advanced stage development costs. For the years ended December 31, 2002, 2001 and 2000, the total amount of interest capitalized was \$575.5 million, \$498.7 million and \$207.0 million, including \$114.2 million, \$136.0 million and \$36.0 million, respectively, of interest incurred on funds borrowed for specific construction projects and \$461.3 million, \$362.7 million and \$171.0 million, respectively of interest incurred on general corporate funds used for construction. 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, 2002, reflects the increase in the Company's power plant construction program. However, the Company expects that the amount of interest capitalized will decrease in future periods as the power plants in construction are completed and as a result of the current suspension of certain of the Company's development projects.

In accordance with SFAS No. 34, the Company determines which debt instruments best represent a reasonable measure of the cost of financing construction assets in terms of interest cost incurred that otherwise

could have been avoided. These debt instruments and associated interest cost are included in the calculation of the weighted average interest rate used for capitalizing interest on general funds. The primary debt instruments included in the rate calculation of interest incurred on general corporate funds, are the Company's Senior Notes, the Company's term loan facility and the \$600.0 million and the \$400.0 million revolving credit facilities.

## 6. Goodwill and Other Intangible Assets

On January 1, 2002, the Company adopted SFAS No. 142, "Goodwill and Other Intangible Assets," which requires that all intangible assets with finite useful lives be amortized and that goodwill and intangible assets with indefinite lives not be amortized, but rather tested upon adoption and at least annually for impairment. The Company was required to complete the initial step of a transitional impairment test within six months of adoption of SFAS No. 142 and to complete the final step of the transitional impairment test by the end of the fiscal year. Any future impairment losses will be reflected in operating income or loss in the consolidated statements of operations. The Company completed both the transitional goodwill impairment test and the first annual goodwill impairment test as required and determined that the fair value of the reporting units with goodwill exceeded their net carrying values. Therefore, the Company did not record any impairment expense.

In accordance with the standard, the Company discontinued the amortization of its recorded goodwill as of January 1, 2002, identified reporting units based on its current segment reporting structure and allocated all recorded goodwill, as well as other assets and liabilities, to the reporting units. A reconciliation of previously reported net income and earnings per share to the amounts adjusted for the exclusion of goodwill amortization is provided below (in thousands, except per share amounts):

	<u>2002</u>	<u>2001</u>	<u>2000</u>
Reported income before discontinued operations and cumulative effect of accounting changes . . .	\$ 49,092	\$586,311	\$332,803
Add: Goodwill amortization . . . . .	—	896	29
Pro forma income before discontinued operations and cumulative effect of accounting changes . . .	49,092	587,207	332,832
Discontinued operations and cumulative effect of accounting changes, net of tax . . . . .	<u>69,526</u>	<u>37,181</u>	<u>36,281</u>
Pro forma net income . . . . .	<u>\$118,618</u>	<u>\$624,388</u>	<u>\$369,113</u>
Basic earnings per share			
As reported . . . . .	\$ 0.33	\$ 2.05	\$ 1.31
Pro forma . . . . .	0.33	2.06	1.31
Diluted earnings per share			
As reported . . . . .	\$ 0.33	\$ 1.80	\$ 1.18
Pro forma . . . . .	0.33	1.80	1.18

Recorded goodwill, by segment, as of December 31, 2002 and December 31, 2001, was (in thousands):

	<u>December 31, 2002</u>	<u>December 31, 2001</u>
Electric Generation and Marketing . . . . .	\$ —	\$ —
Oil and Gas Production and Marketing . . . . .	—	—
Corporate, Other and Eliminations . . . . .	<u>34,589</u>	<u>29,375</u>
Total . . . . .	<u>\$34,589</u>	<u>\$29,375</u>

The increase in goodwill during 2002 is due to a \$5.2 million contingent payment that the Company paid based on certain performance incentives met by PSM under the terms of the PSM purchase agreement. Should PSM continue to meet the performance objectives, annual contingent payments of \$5.2 million will be made in 2003-2005, each of which will increase the goodwill balance. Subsequent goodwill impairment tests will be performed, at a minimum, in December of each year, in conjunction with the Company's annual reporting process.

The Company also reassessed the useful lives and the classification of its identifiable intangible assets and determined that they continue to be appropriate. The components of the amortizable intangible assets consist of the following (in thousands):

	Weighted Average Useful Life/ Contract Life	As of December 31, 2002		As of December 31, 2001	
		Carrying Amount	Accumulated Amortization	Carrying Amount	Accumulated Amortization
Patents . . . . .	5	\$ 485	\$ (231)	\$ 485	\$ (134)
Power sales agreements . . . . .	14	156,814	(106,227)	156,814	(86,352)
Fuel supply and fuel management contracts . . . . .	26	22,198	(4,105)	22,198	(3,216)
Geothermal lease rights . . . . .	20	19,518	(350)	19,493	(250)
Steam purchase agreement . . . . .	14	5,201	(486)	—	—
Other . . . . .	5	<u>320</u>	<u>(71)</u>	<u>277</u>	<u>(25)</u>
Total . . . . .		<u>\$204,536</u>	<u>\$(111,470)</u>	<u>\$199,267</u>	<u>\$(89,977)</u>

Amortization expense of other intangible assets was \$21.5 million, \$23.9 million and \$22.8 million, in 2002, 2001 and 2000, respectively. Assuming no future impairments of these assets or additions as the result of acquisitions, annual amortization expense will be \$5.3 million in 2003, \$4.9 million in 2004, \$4.8 million in 2005, \$4.8 million in 2006, and \$4.8 million in 2007.

## 7. Acquisitions

The Company seeks to acquire power generating facilities and certain oil and gas properties that provide significant potential for revenue, cash flow and earnings growth, and that provide the opportunity to enhance the operating efficiency of its plants. Acquisition activity is dependent on the availability of financing on attractive terms and the expectation of returns that meets the Company's long-term requirements. The following material mergers and acquisitions were consummated during the years ended December 31, 2001 and 2000. There were no mergers or acquisitions consummated during the year ended December 31, 2002. All business combinations were accounted for as purchases, with the exception of the Encal pooling-of-interests transaction. For all business combinations accounted for as purchases, the results of operations of the acquired companies were incorporated into the Company's Consolidated Financial Statements commencing on the date of acquisition.

### *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 APB Opinion No. 16, "Business Combinations" ("APB 16"). Encal operated under the same fiscal year end as Calpine, and accordingly, Encal's balance sheet as of December 31, 2000, and the statements of operations, shareholders' equity and cash flows for the fiscal year ended December 31, 2000, have been combined with the Company's Consolidated Financial Statements. The Company incurred \$41.6 million in nonrecurring merger costs for this transaction. Upon completion of the acquisition, the Company gained approximately 664 billion cubic feet equivalent of proved natural gas reserves, net of royalties. This transaction also provided access to firm gas transportation capacity from western Canada to California and the eastern U.S., and an accomplished

management team capable of leading the Company's business expansion in Canada. In addition, Encal had proved undeveloped acreage totaling approximately 1.2 million acres.

#### ***Hidalgo Transaction***

On March 30, 2000, the Company purchased a 78.5% interest in the 502-megawatt Hidalgo Energy Center ("Hidalgo") which was under construction in Edinburg, Texas, from Duke Energy North America for \$235.0 million. The purchase included a cash payment of \$134.0 million and the assumption of a \$101.0 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 \$71.0 million in cash and assumed a capital lease obligation relating to the Stony Brook Power Plant and an operating lease obligation relating to the KIAC 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 ("Freestone") from Energy Corporation. Freestone is a 1,052-megawatt natural gas-fired energy center under development in Freestone County, Texas. 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.

#### ***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. 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 the 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. The Company subsequently changed QMCC's name to Calpine Canada Natural Gas, Ltd. ("CCNG").

#### ***Oneta Transaction***

On July 20, 2000, the Company completed the acquisition of the 1,138-megawatt natural gas-fired Oneta Energy Center, ("Oneta") in Coseta, Oklahoma, from Panda Energy International, Inc. for total proceeds of \$22.9 million, consisting of \$20.1 million of cash and \$2.8 million of a forgiven note receivable.

#### ***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). Additionally, the purchase agreement provided for

contingent consideration not to exceed \$200.0 million upon perfection of certain earnout projects, which were perfected during 2001 and resulted in payments of \$195.3 million.

#### ***TriGas Transaction***

On November 15, 2000, the Company 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 provided Calpine with natural gas reserves to fuel its Calgary Energy Centre, and a 26.6% working interest in the East Crossfield Gas Plant, a majority interest in 63 miles of pipeline that conducts the gas to two nearby gas-fired power generation facilities, 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). The Company recorded goodwill initially valued at \$19.0 million, prior to subsequent contingent payments and amortization taken during 2001. Prior to the adoption of SFAS No. 142, the goodwill was being amortized over a 20-year life. 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.

#### ***Saltend Transaction***

On August 24, 2001, the Company acquired a 100% interest in and assumed operations of the Saltend Energy Centre (“Saltend”), a 1,200-megawatt natural gas-fired power plant located at Saltend near Hull, Yorkshire, England. The Company purchased the cogeneration facility from an affiliate of Entergy Corporation for £560.4 million (US\$811.3 million at exchange rates at the closing of the acquisition). Saltend began commercial operation in November 2000 and is one of the largest natural gas-fired electric power generating facilities in England.

#### ***Hog Bayou and Pine Bluff Transactions***

On September 12, 2001, the Company purchased the remaining 33.3% interests in the 247-megawatt Hog Bayou Energy Center (“Hog Bayou”) and the 213-megawatt Pine Bluff Energy Center (“Pine Bluff”) from Houston, Texas-based InterGen (North America), Inc. for approximately \$9.6 million and \$1.4 million of a forgiven note receivable.

#### ***Westcoast Transaction***

On September 20, 2001, the Company’s wholly owned subsidiary, Canada Power Holdings Ltd., acquired and assumed operations of two Canadian power generating facilities from British Columbia-based Westcoast Energy Inc. (“Westcoast”) for C\$325.2 million (US\$207.0 million at exchange rates at the closing of the

acquisition). The Company acquired a 100% interest in the Island Cogeneration facility (“Island”), a 250-megawatt natural gas-fired electric generating facility then in the commissioning phase of construction and located near Campbell River, British Columbia on Vancouver Island. The Company also acquired a 50% interest in the 50-megawatt Whitby Cogeneration facility (“Whitby”) located in Whitby, Ontario.

***California Energy General Corporation and CE Newbury, Inc. Transaction***

On October 16, 2001, the Company acquired 100% of the voting stock of California Energy General Corporation (“California Energy”) and CE Newbury, Inc. (“CE Newbury”) from MidAmerican Energy Holdings Company for \$22.0 million. The transaction included geothermal resource assets, contracts, leases and development opportunities associated with the Glass Mountain Known Geothermal Resource Area (“Glass Mountain KGRA”) located in Siskiyou County, California, approximately 30 miles south of the Oregon border. These purchases were directly related to the Company’s plans to develop the 49.5-megawatt Fourmile Hill Geothermal Project located in the Glass Mountain KGRA.

***Michael Petroleum Transaction***

On October 22, 2001, the Company completed the acquisition of 100% of the voting stock of Michael Petroleum Corporation (“Michael”), a natural gas exploration and production company, for cash of \$314.0 million, plus the assumption of \$54.5 million of debt. The acquired assets consisted of approximately 531 wells, producing approximately 33.5 net mmcf/day of which 90 percent is gas, and developed and non-developed acreage totaling approximately 82,590 net acres at year end.

***Delta, Metcalf and Russell City Transactions***

On November 6, 2001, the Company acquired Bechtel Enterprises Holdings, Inc.’s 50% interest in the 874-megawatt Delta Energy Center (“Delta”), the 600-megawatt Metcalf Energy Center (“Metcalf”) and the 600-megawatt Russell City Energy Center (“Russell City”) for approximately \$154.0 million and the assumption of approximately \$141.0 million of debt. As a result of this acquisition, the Company now owns a 100% interest in all three projects.

The initial purchase price allocation for all material business combinations initiated after June 30, 2001, the effective date of SFAS No. 141, is shown below. As of December 31, 2001, the Company had not finalized the purchase price allocation for Saltend, Michael, or Westcoast. The allocations for the three acquisitions were subsequently completed during 2002, and the final allocations and the allocations as reported at December 31, 2001, are shown below (in thousands):

**Final Purchase Price Allocation**

	<u>Saltend</u>	<u>Michael Petroleum</u>	<u>Westcoast</u>
Current assets . . . . .	\$ 16,725	\$ 5,970	\$ 14,390
Property, plant and equipment . . . . .	908,204	532,145	200,514
Other assets . . . . .	9,523	—	—
Investments in power plants . . . . .	—	—	26,000
Current liabilities . . . . .	(21,900)	(16,852)	(7,932)
Derivative liability . . . . .	—	(1,862)	—
Notes payable . . . . .	—	(54,500)	—
Other long-term liability . . . . .	(8,045)	—	—
Deferred tax liabilities, net . . . . .	<u>(93,230)</u>	<u>(150,944)</u>	<u>(25,947)</u>
Net purchase price . . . . .	<u>\$811,277</u>	<u>\$ 313,957</u>	<u>\$207,025</u>

## Initial Purchase Price Allocation

	<u>Saltend</u>	<u>Michael Petroleum</u>	<u>Westcoast</u>
Current assets . . . . .	\$ 27,363	\$ 5,970	\$ 4,468
Property, plant and equipment . . . . .	906,801	535,007	212,902
Other assets . . . . .	1,478	—	—
Investments in power plants . . . . .	—	—	25,907
Current liabilities . . . . .	(21,900)	(16,852)	(6,802)
Derivative liability . . . . .	—	(1,862)	—
Notes payable . . . . .	—	(54,500)	—
Deferred tax liabilities, net . . . . .	<u>(95,671)</u>	<u>(151,946)</u>	<u>(24,408)</u>
Net purchase price . . . . .	<u>\$818,071</u>	<u>\$ 315,817</u>	<u>\$212,067</u>

The \$6.8 million decrease in the net purchase price of Saltend occurred primarily due to a \$10.1 million working capital adjustment that was paid to the Company during 2002. This reduction was partially offset by a \$4.0 million adjustment to reflect a previously unrecorded receivable held by Saltend as a result of liquidated damages Saltend owed for delays in achieving commercial operations during 2000.

The \$5.0 million decrease in the net purchase price of Westcoast occurred primarily due to a performance adjustment payment to the Company to compensate for certain plant specifications that were not met of \$3.4 million and a \$4.2 million compensation payment for the loss of certain tax pools that were previously represented to be held by Westcoast and were used in part to help determine the original purchase price. Both amounts were paid to the Company during 2002. These reductions were partially offset by a working capital adjustment of \$2.4 million that the Company paid during 2002.

## Pro Forma Effects of Acquisitions

Acquired subsidiaries are consolidated upon acquisition. The table below reflects the Company's unaudited pro forma combined results of operations for all business combinations during 2001, as if the acquisitions had taken place at the beginning of fiscal year 2001. The Company's combined results include the effects of, WRMS, Saltend, Hog Bayou, Pine Bluff, Island, Whitby, California Energy, CE Newbury, Michael, Highland, Delta, Metcalf, and Russell City (in thousands, except per share amounts):

	<u>2001</u>
Total revenue . . . . .	\$6,975,398
Income before discontinued operations and cumulative effect of accounting changes	\$ 587,331
Net income . . . . .	\$ 624,511
Net income per basic share . . . . .	\$ 2.06
Net income per diluted share . . . . .	\$ 1.80

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 2001 acquisitions had been effective at the beginning of fiscal year 2001. 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.

## 8. Sale/Leaseback Transactions

In 2001 the Company completed the following sale/leaseback transactions, which resulted in operating leases. All counterparties in the sale/leaseback transactions are unrelated to the Company. In connection with these transactions, the Company recorded deferred gains (losses) which are being amortized as a reduction of (addition to) operating lease expense over the respective remaining lives of the leases.

On September 30, 2001, the Company completed a leveraged lease financing transaction of its Aidlin project. Under the terms of the agreement, the facility was incorporated into the Company's geothermal lease facility, which the Company originally entered into on May 7, 1999. The Company received \$29.0 million in gross proceeds and recorded a deferred gain of approximately \$6.8 million.

On October 18, 2001, the Company completed leveraged lease financing transactions for the South Point and RockGen facilities raising \$500.0 million in gross proceeds, resulting in a deferred gain of approximately \$21.1 million. In connection with these transactions, Calpine Corporation provided a guarantee for the obligations of its subsidiaries under the leases. The lessors raised a significant portion of the capital necessary to fund this transaction by issuing pass through trust certificates with an aggregate principal amount of \$654.5 million. A portion of the pass through trust certificates was used to fund the Broad River Energy Center financing. See Note 16 for more information regarding the Broad River financing, which prior to the restatement described in Note 2, was accounted for as a sale/leaseback operating lease. In effect, the pass through certificates evidence the debt component of these sale/leaseback transactions. The pass through certificates were issued in two tranches: the first, consisting of \$454.5 million in aggregate principal amount of 8.4% Series A Certificates due May 30, 2012, and the second, consisting of \$200.0 million in aggregate principal amount of 9.825% Series B Certificates due May 30, 2019.

The transactions involving South Point and RockGen utilize special-purpose entities formed by the lessor with the sole purpose of owning a power generation facility. The Company is not the owner of the SPE nor does the Company have any direct or indirect ownership interest in each respective SPE; therefore the SPEs are appropriately not consolidated as subsidiaries of the Company.

## 9. Investments in Power Projects

The Company's investments in power projects are integral to its operations. In accordance with APB Opinion No. 18, "The Equity Method of Accounting For Investments in Common Stock" and FASB Interpretation No. 35, "Criteria for Applying the Equity Method of Accounting for Investments in Common Stock (An Interpretation of APB Opinion No. 18)," they are accounted for under the equity method, and are as follows (in thousands):

	Ownership Interest as of December 31, 2002	Investment Balance at December 31,	
		2002	2001
Acadia Power Plant .....	50.0%	\$282,634	\$228,728
Grays Ferry Power Plant .....	40.0%	42,322	43,601
Aries Power Plant .....	50.0%	30,936	26,133
Gordonsville Power Plant .....	50.0%	20,892	21,687
Lockport Power Plant(1) .....	11.4%	—	15,919
Whitby Cogeneration .....	50.0%	33,502	25,848
Other(2) .....	—	11,116	30,795
Total investments in power projects .....		<u>\$421,402</u>	<u>\$392,711</u>

(1) On March 29, 2002, the Company sold its 11.4% interest in the Lockport Power Plant in exchange for a \$27.3 million note receivable, which was subsequently paid in full, from Fortistar Tuscarora LLC, a wholly owned subsidiary of Fortistar LLC, the project's managing general partner. This transaction resulted in a pre-tax gain of \$9.7 million recorded in other income.

(2) The 2001 balance includes the Company's \$25.4 million investment in Endur, which is consolidated in the Company's financial statements in 2002.

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

	December 31,		
	2002	2001	2000
Condensed statements of operations:			
Revenue .....	\$ 372,212	\$ 401,452	\$ 617,914
Gross profit .....	151,784	148,476	217,777
Income from continuing operations .....	132,911	99,052	161,852
Net income .....	70,596	83,161	80,812
Condensed balance sheets:			
Current assets .....	\$ 133,801	\$ 129,189	
Non-current assets .....	<u>1,740,056</u>	<u>1,379,134</u>	
Total assets .....	<u>\$1,873,857</u>	<u>\$1,508,323</u>	
Current liabilities .....	\$ 132,516	\$ 145,524	
Non-current liabilities .....	<u>946,383</u>	<u>687,645</u>	
Total liabilities .....	<u>\$1,078,899</u>	<u>\$ 833,169</u>	

The debt on the books of the unconsolidated power projects is not reflected on the Company's balance sheet. At December 31, 2002, investee debt is approximately \$639.3 million. Based on the Company's pro rata ownership share of each of the investments, the Company's share would be approximately \$238.6 million. However, all such debt is non-recourse to the Company.

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

	Income (loss) from Unconsolidated Investments in Power Projects			Distributions		
	For the Years Ended December 31,					
	2002	2001	2000	2002	2001	2000
Grays Ferry Power Plant .....	\$(1,499)	\$ 594	\$ 4,737	\$ —	\$ —	\$ 4,500
Lockport Power Plant .....	1,570	5,562	4,391	—	4,351	3,752
Gordonsville Power Plant .....	5,763	4,453	4,514	2,125	825	2,950
Acadia Energy Center .....	14,590	—	—	11,969	—	—
Aries Power Plant .....	(43)	—	—	—	—	—
Whitby Cogeneration .....	411	684	—	—	637	—
Other .....	<u>(4,302)</u>	<u>(1,860)</u>	<u>10,327</u>	<u>23</u>	<u>170</u>	<u>18,777</u>
Total .....	<u>\$16,490</u>	<u>\$ 9,433</u>	<u>\$23,969</u>	<u>\$14,117</u>	<u>\$5,983</u>	<u>\$29,979</u>
Interest income on loans to power projects(1) .....	<u>\$ 62</u>	<u>\$ 6,792</u>	<u>\$ 4,827</u>			
Total .....	<u>\$16,552</u>	<u>\$16,225</u>	<u>\$28,796</u>			

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

(1) At December 31, 2002 and 2001, loans to power projects represented an outstanding loan to the Company's 32.3% owned investment, Androscoggin Energy Center LLC, in the amount of \$3.1 million. Androscoggin Energy Center LLC is included in the "Other" category throughout this note.

In the fourth quarter of 2002 income from unconsolidated investments was reclassified out of total revenue and are presented as a component of other income from operations. Prior periods have also been reclassified accordingly.

## 10. Notes Receivable

The long-term notes receivable are recorded by discounting expected future cash flows using current interest rates at which similar loans would be made to borrowers with similar credit ratings and remaining maturities. The Company intends to hold these notes to maturity.

As of December 31, 2002, and December 31, 2001, the components of notes receivable were (in thousands):

	<u>December 31,</u> <u>2002</u>	<u>December 31,</u> <u>2001</u>
PG&E (Gilroy) note .....	\$163,584	\$117,698
Panda note.....	30,818	30,818
Other .....	<u>9,555</u>	<u>21,833</u>
Total notes receivable.....	203,957	170,349
Less: Notes receivable, current portion .....	<u>(8,559)</u>	<u>(12,225)</u>
Notes receivable, net of current portion.....	<u>\$195,398</u>	<u>\$158,124</u>

Calpine Gilroy Cogen, LP (“Gilroy”) had a long-term power purchase agreement (“PPA”) with Pacific Gas and Electric Company (“PG&E”) for the sale of energy through 2018. The terms of the PPA provided for 120 megawatts of firm capacity and up to 10 megawatts of as-delivered capacity. On December 2, 1999, the California Public Utilities Commission approved the restructuring of the PPA between Gilroy and PG&E. Under the terms of the restructuring, PG&E and Gilroy are each released from performance under the PPA effective November 1, 2002. Under the restructured contract, in addition to the normal capacity revenue for the period, Gilroy has earned from September 1999 to October 2002 restructured capacity revenue it would have earned over the November 2002 through March 2018 time period, for which PG&E has issued notes to the Company. These notes will be paid by PG&E during the period from February 2003 to September 2014. The first scheduled note repayment of \$1.7 million was received in February 2003. See Note 23 for additional discussion of transactions with PG&E.

In June 2000 the Company entered into a series of turbine sale contracts with and acquired the development rights to construct, own and operate the Oneta Energy Center from a subsidiary of Panda Energy International, Inc (“Panda”). As part of the transaction, Panda was extended a loan from the Company bearing an interest rate of LIBOR plus 5%. The loan is collateralized by Panda’s carried interest in the income generated from the Oneta Energy Center, which has achieved partial commercial operations. The loan, while due in December 2003, is classified as a long-term receivable as of December 31, 2002, due to the probability that repayment may be delayed by a slow down in full completion of the Oneta facility.

## 11. Canadian Income Trust

On August 29, 2002, the Company announced it had completed a Cdn\$230 million (US\$147.5 million) initial public offering of its Canadian income trust fund — Calpine Power Income Fund (the “Fund”). The 23 million Trust Units issued to the public were priced at Cdn\$10 per unit, to initially yield 9.35% per annum. The Fund indirectly owns interests in two of Calpine’s Canadian power generating assets, the Island Cogeneration Facility, and the Calgary Energy Centre, which is under construction, and has a loan to a Calpine subsidiary which owns Calpine’s other Canadian power generating asset, the Whitby cogeneration plant. Combined, these assets represent approximately 550 net megawatts of power generating capacity.

On September 20, 2002, the syndicate of underwriters fully exercised the over-allotment option that it was granted as part of the initial public offering of Trust Units and acquired 3,450,000 additional Trust Units of the Fund at Cdn\$10 per Trust Unit, generating Cdn\$34.5 million (US\$21.9 million).

The Company intends to retain a substantial subordinated equity interest and an operating and management role in the Calpine Power Income Fund and the Fund assets and, accordingly, has control, therefore, the financial results of the Fund are consolidated in the Company’s financial statements. At

December 31, 2002, the Company held 49% of the Fund's authorized Trust Units. The proceeds from the public offering of Trust Units were recorded as minority interests in the Company's balance sheet. See Subsequent Events (Note 29) for a description of the Company's secondary offering of Warranted Units in February 2003.

## **12. Discontinued Operations**

As a result of the significant contraction in the availability of capital for participants in the energy sector, the Company has adopted a strategy of conserving its core strategic assets. Implicit within this strategy is the disposal of certain less strategically important assets, which serves primarily to strengthen the Company's balance sheet through repayment of debt. Set forth below are all of the Company's asset disposals by reportable segment as of December 31, 2002:

### ***Oil and Gas Production and Marketing***

On August 29, 2002, the Company completed the sale of certain non-strategic oil and gas properties ("Medicine River properties") located in central Alberta to NAL Oil and Gas Trust and another institutional investor for Cdn\$125.0 million (US\$80.1 million). As a result of the sale, the Company recorded a pre-tax gain of \$21.9 million.

On October 1, 2002, the Company completed the sale of substantially all of its British Columbia oil and gas properties to Calgary, Alberta-based Pengrowth Corporation for gross proceeds of approximately Cdn\$387.5 million (US\$244.3 million). Of the total consideration, the Company received US\$155.9 million in cash. The remaining US\$88.4 million of consideration was paid by Pengrowth Corporation's purchase in the open market of US\$203.2 million in aggregate principal amount of the Company's debt securities. As a result of the transaction, the Company recorded a US\$37.4 million pre-tax gain on the sale of the properties and a gain on the extinguishment of debt of US\$114.8 million. The Company used approximately US\$50.4 million of cash proceeds to repay amounts outstanding under its US\$1.0 billion term loan. See Note 18 for more information about the specific debt securities delivered to the Company as a result of this transaction.

On October 31, 2002, the Company sold all of its oil and gas properties in Drake Bay Field located in Plaquemines Parish, Louisiana for approximately \$3 million to Goldking Energy Corporation. As a result of the sale, the Company recognized a pre-tax loss of \$0.02 million.

### ***Electric Generation and Marketing***

On December 16, 2002, the Company completed the sale of the 180-megawatt DePere Energy Center in DePere, Wisconsin. The facility was sold to Wisconsin Public Service for \$120.4 million, which included \$72.0 million in cash at closing and a \$48.4 million payment due in December 2003. As a result of the sale, the Company recognized a pre-tax gain of \$35.8 million. On December 17, 2002, the Company sold its right to the December 2003 payment to a third party for \$46.3 million, and recognized a pre-tax loss of \$2.1 million.

### ***Summary***

The Company made reclassifications to current and prior period financial statements to reflect the sale or designation as 'held for sale' of these oil and gas and power plant assets and liabilities and to separately classify the operating results of the assets sold and gain on sale of those assets from the operating results of continuing operations.

The tables below present significant components of the Company's income from discontinued operations for 2002, 2001 and 2000, respectively (in thousands):

	<b>2002</b>		
	<b>Electric Generation and Marketing</b>	<b>Oil and Gas Production and Marketing</b>	<b>Total</b>
Total revenue .....	<u>\$16,915</u>	<u>\$76,486</u>	<u>\$ 93,401</u>
Gain on disposal before taxes .....	\$35,840	\$59,288	\$ 95,128
Operating income from discontinued operations before taxes .....	<u>5,253</u>	<u>16,181</u>	<u>21,434</u>
Income from discontinued operations before taxes ....	<u>\$41,093</u>	<u>\$75,469</u>	<u>\$116,562</u>
Gain on disposal, net of tax .....	\$21,377	\$35,153	\$ 56,530
Operating income from discontinued operations, net of tax .....	<u>3,465</u>	<u>9,531</u>	<u>12,996</u>
Income from discontinued operations, net of tax .....	<u>\$24,842</u>	<u>\$44,684</u>	<u>\$ 69,526</u>
	<b>2001</b>		
	<b>Electric Generation and Marketing</b>	<b>Oil and Gas Production and Marketing</b>	<b>Total</b>
Total revenue .....	<u>\$17,113</u>	<u>\$140,040</u>	<u>\$157,153</u>
Gain on disposal before taxes .....	\$ —	\$ —	\$ —
Operating income from discontinued operations before taxes .....	<u>2,520</u>	<u>70,375</u>	<u>72,895</u>
Income from discontinued operations before taxes ....	<u>\$ 2,520</u>	<u>\$ 70,375</u>	<u>\$ 72,895</u>
Gain on disposal, net of tax .....	\$ —	\$ —	\$ —
Operating income from discontinued operations, net of tax .....	<u>1,544</u>	<u>34,601</u>	<u>36,145</u>
Income from discontinued operations, net of tax .....	<u>\$ 1,544</u>	<u>\$ 34,601</u>	<u>\$ 36,145</u>
	<b>2000</b>		
	<b>Electric Generation and Marketing</b>	<b>Oil and Gas Production and Marketing</b>	<b>Total</b>
Total revenue .....	<u>\$7,178</u>	<u>\$133,599</u>	<u>\$140,777</u>
Gain on disposal before taxes .....	\$ —	\$ —	\$ —
Operating income from discontinued operations before taxes .....	<u>818</u>	<u>66,917</u>	<u>67,735</u>
Income from discontinued operations before taxes ....	<u>\$ 818</u>	<u>\$ 66,917</u>	<u>\$ 67,735</u>
Gain on disposal, net of tax .....	\$ —	\$ —	\$ —
Operating income from discontinued operations, net of tax .....	<u>484</u>	<u>35,797</u>	<u>36,281</u>
Income from discontinued operations, net of tax .....	<u>\$ 484</u>	<u>\$ 35,797</u>	<u>\$ 36,281</u>

The table below presents the assets and liabilities held for sale on the Company's balance sheet as of December 31, 2002 and December 31, 2001, respectively:

	December 31, 2002			December 31, 2001		
	Electric Generation and Marketing	Oil and Gas Production and Marketing	Total	Electric Generation and Marketing	Oil and Gas Production and Marketing	Total
Current assets of discontinued operations . . . . .	\$—	\$—	\$—	\$ —	\$ 9,484	\$ 9,484
Long-term assets of discontinued operations . . . . .	—	—	—	74,415	257,665	332,080
Total assets of discontinued operations . . . . .	<u>\$—</u>	<u>\$—</u>	<u>\$—</u>	<u>\$74,415</u>	<u>\$267,149</u>	<u>\$341,564</u>
Current liabilities of discontinued operations . . . . .	\$—	\$—	\$—	\$ —	\$ 12,059	\$ 12,059
Long-term liabilities of discontinued operations . . . . .	—	—	—	7,488	—	7,488
Total liabilities of discontinued operations . . . . .	<u>\$—</u>	<u>\$—</u>	<u>\$—</u>	<u>\$ 7,488</u>	<u>\$ 12,059</u>	<u>\$ 19,547</u>

The Company allocates interest expense associated with consolidated non-specific debt to its discontinued operations based on a ratio of the net assets of its discontinued operations to the Company's total consolidated net assets, in accordance with EITF Issue No. 87-24, "Allocation of Interest to Discontinued Operations" ("EITF Issue No. 87-24"). Also in accordance with EITF Issue No. 87-24, the Company allocated interest expense to its British Columbia oil and gas properties for approximately \$50.4 million of debt the Company is required to repay under the terms of its \$1.0 billion term loan. In 2002, 2001 and 2000, the Company allocated interest expense of \$6.2 million, \$4.5 million, and \$3.9 million, respectively, to its discontinued operations.

### 13. Notes Payable and Borrowings Under Lines of Credit and Term Loan

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

	Borrowings Outstanding December 31,		Letters of Credit Outstanding December 31,	
	2002	2001	2002	2001
Corporate term loan . . . . .	\$ 949,565	\$ —	\$ —	\$ —
Corporate revolving lines of credit . . . . .	340,000	—	573,899	373,224
Michael Petroleum note payable . . . . .	—	64,750	—	250
Other . . . . .	8,952	33,238	—	10,810
Total notes payable and borrowings under lines of credit and term loan . . . . .	<u>\$1,298,517</u>	<u>\$97,988</u>	<u>\$573,899</u>	<u>\$384,284</u>
Less: notes payable and borrowings under lines of credit, current portion, and term loan . . . . .	<u>340,703</u>	<u>23,238</u>		
Notes payable and borrowings under lines of credit, net of current portion, and term loan . . . . .	<u>\$ 957,814</u>	<u>\$74,750</u>		

In March 2002, the Company closed a new secured credit agreement which at that point was comprised of (a) a \$1.0 billion revolving credit facility expiring on May 24, 2003 and (b) a two-year term loan facility for up to \$600.0 million. In May 2002, the term loan facility was subsequently increased to \$1.0 billion through a

term of May 10, 2004, while the amount of the revolving credit facility was decreased to \$600.0 million. Any letters of credit issued under the \$600.0 million revolving credit facility on or prior to May 24, 2003 can be extended for up to one year at our option so long as they expire no later than five business days prior to the maturity date of the term-loan facility.

As part of the March 2002 closings, the Company also amended its existing \$400.0 million unsecured revolving credit agreement to provide, among other things, security for borrowings under that agreement. The \$400.0 million revolving credit facility matures on May 23, 2003.

Security for the \$400.0 million and \$600.0 million revolving credit facilities as well as the \$1.0 billion term loan facility originally included (a) a pledge of the capital stock of the Company's subsidiaries holding, directly or indirectly (i) the interests in the Company's U.S. natural gas properties, (ii) the Saltend power plant located in the United Kingdom and (iii) the Company's equity investment in nine U.S. power plants, and (b) a pledge by certain of the Company's subsidiaries of a total of 65% of the capital stock of Calpine Canada Energy Ltd., the direct or indirect parent company of all of our Canadian subsidiaries, including those holding all of our Canadian natural gas properties.

As part of the initial funding of the term loan in May 2002, the Company expanded the security for the revolving credit and term loan facilities by pledging to the lenders substantially all of the Company's remaining first tier domestic subsidiaries, excluding CES. At the time, the security also included direct liens on the Company's domestic natural gas properties.

At December 31, 2002, the Company had \$949.6 million in funded borrowings outstanding under the term loan facility, and \$340.0 million in funded borrowings and \$573.9 million outstanding in letters of credit under its two revolving credit facilities. At December 31, 2001, the Company had no outstanding borrowings and \$373.2 million outstanding in letters of credit under its \$400.0 million revolving 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 term loan and credit facilities specify that the Company maintain certain covenants, with which the Company was in compliance as of December 31, 2002 and 2001. Commitment fees related to the revolving lines of credit are charges based on unused credit amounts. The interest rate on the term loan was 5.2% at December 31, 2002; and the interest rate on this facility ranged from 5.2% to 7.5% during 2002. The interest rate on the \$600.0 million revolving credit facility was 4.7% at December 31, 2002; and the interest rate on this facility ranged from 4.6% to 6.8% during 2002. The interest rate on the \$400.0 million revolving credit facility was 3.9% at December 31, 2002; and the interest rate on this facility ranged from 3.8% to 5.8% during 2002, and from 5.5% to 8.0% during 2001.

As part of the Company's acquisition of Michael Petroleum Corporation ("MPC") through its wholly owned subsidiary Calpine Natural Gas Company, the Company assumed a \$75.0 million three-year revolving credit facility with Bank One, N.A. and other banks. Amounts outstanding under the facility bore variable interest. The interest rate ranged from 4.3% to 5.0% during 2002. The line of credit was secured by the Company's oil and gas properties. The Company was out of compliance as of December 31, 2001, with a covenant under the loan agreement. Subsequent to December 31, 2001, the Company initiated the process to obtain a waiver for the covenant but chose to instead repay the outstanding balance under the loan agreement. On March 13, 2002, the Company repaid the Michael Petroleum note payable, which had a balance of \$64.8 million at repayment.

#### **14. Capital Lease Obligations**

During 2000 and 2001 the Company assumed and consolidated capital leases in conjunction with certain acquisitions. As of December 31, 2002 and 2001, the asset balances for the leased assets totaled \$201.6 million and \$198.8 million, respectively, with accumulated amortization of \$20.4 million and \$11.1 million, respectively. The primary types of property leased by the Company are power plants and related equipment. The leases generally provide for the lessee to pay taxes, maintenance, insurance, and certain other operating costs of the leased property. The lease terms range from 13 to 28 years.

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, 2002, (in thousands):

Year Ending December 31:	
2003 .....	\$ 19,058
2004 .....	19,250
2005 .....	19,328
2006 .....	19,947
2007 .....	20,018
Thereafter .....	<u>304,039</u>
Total minimum lease payments .....	401,640
Less: Amount representing interest(1) .....	<u>200,466</u>
Present value of net minimum lease payments .....	\$201,174
Less: Capital lease obligation, current portion .....	<u>3,502</u>
Capital lease obligation, net of current portion .....	<u><u>\$197,672</u></u>

(1) Amount necessary to reduce net minimum lease payments to present value calculated at the incremental borrowing rate at the time of acquisition.

#### 15. Zero-Coupon Convertible Debentures

On April 30, 2001, the Company completed the sale of \$1.0 billion of Zero-Coupon Convertible Debentures Due 2021 (“Zero Coupons”) in a private placement under Rule 144A of the Securities Act of 1933.

In December 2001 the Company repurchased \$122.0 million in aggregate principal amount of its Zero Coupons in open-market purchases at a discount, and recorded a pre-tax gain of \$11.9 million after the write-off of related financing costs. In January and February 2002 the Company repurchased an additional \$192.5 million of its Zero Coupons at a discount and recorded a pre-tax gain of \$3.5 million, after the write-off of related financing costs. On April 30, 2002, the Company repurchased the remaining \$685.5 million in aggregate principal amount of its Zero Coupons at par pursuant to a scheduled put provided for by the terms of the Zero Coupons.

The effective interest rate, after amortization of deferred financing costs, was 2.5% in 2002, and 2.3% in 2001.

## 16. Construction/Project Financing

The components of construction/project financing as of December 31, 2002 and 2001, are (in thousands):

Projects	Outstanding at December 31,		Letters of Credit Outstanding at December 31,	
	2002	2001	2002	2001
Calpine Construction Finance Company . . . . .	\$ 970,110	\$ 967,576	\$29,890	\$18,600
Calpine Construction Finance Company II . . . . .	2,469,642	2,425,834	3,224	57,303
Pasadena Cogeneration, L.P.(1) . . . . .	388,867	387,085	—	—
Broad River Energy LLC(1) . . . . .	300,974	300,000	—	—
Siemens Westinghouse Power Corporation . . . . .	169,180	—	—	—
Blue Spruce Energy Center LLC . . . . .	83,540	—	—	—
Peaker Financing . . . . .	50,000	—	—	—
Calpine Newark, Inc. . . . .	50,000	—	—	—
Calpine Parlin Inc. . . . .	37,000	—	—	—
Total . . . . .	<u>4,519,313</u>	<u>4,080,495</u>	<u>\$33,114</u>	<u>\$75,903</u>
Less: current portion . . . . .	<u>1,307,291</u>	—		
Long-term project financing . . . . .	<u>\$3,212,022</u>	<u>\$4,080,495</u>		

(1) See Note 2 for information regarding this transaction.

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. The lead arranger was The Bank of Nova Scotia and the lead arranger syndication agent was Credit Suisse First Boston. The non-recourse credit facility is utilized to finance the construction of certain of the Company's gas-fired power plants currently under development. The Company currently intends to refinance this construction facility prior to its four-year maturity in November 2003. As of December 31, 2002, the Company had \$970.1 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, 2002. The interest rate at December 31, 2002 and 2001, was 2.9% and 3.4%, respectively. The interest rate ranged from 2.9% to 5.5% during 2002.

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. The lead arrangers were The Bank of Nova Scotia and Credit Suisse First Boston. The non-recourse credit facility is utilized to finance the construction of certain of the Company's gas-fired power plants currently under development. The Company currently intends to refinance or extend this construction facility prior to its four-year maturity in November 2004. As of December 31, 2002, the Company had \$2.5 billion 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, 2002. The interest rate at December 31, 2002 and 2001, was 2.9% and 3.7%, respectively. The interest rate ranged from 2.9% to 5.5% during 2002.

In September 2000, the Company completed the financing for both Phase I and Phase II of the Pasadena, Texas cogeneration project. Under the terms of the project financing, the Company received \$400.0 million in gross proceeds. At December 31, 2002, the Company had \$388.9 million in borrowings outstanding which mature in 2048. The interest rate at December 31, 2002 was 8.6%.

In October 2001, the Company completed the financing for the Broad River Energy Center in South Carolina. Under the terms of the project financing, the Company received \$300.0 million in gross proceeds. At

December 31, 2002, the Company had \$301.0 million in borrowings outstanding which mature in 2041. The interest rate at December 31, 2002 was 8.1%.

On January 31, 2002, the Company's subsidiary, Calpine Construction Management Company, Inc., entered into an agreement with Siemens Westinghouse Power Corporation to reschedule the production and delivery of gas and steam turbine generators and related equipment. Under the agreement, the Company obtained vendor financing of up to \$232.0 million bearing variable interest for gas and steam turbine generators and related equipment. The financing is due prior to the earliest of the equipment site delivery date specified in the agreement, the Company's requested date of turbine site delivery or June 25, 2003. At December 31, 2002, there was \$169.2 million in borrowings outstanding under this agreement. The interest rate at December 31, 2002, was 6.6%. The interest rate ranged from 6.6% to 7.6% during 2002.

On May 14, 2002, the Company's subsidiary, Calpine California Energy Finance, LLC, entered into an \$100.0 million amended and restated credit agreement with ING Capital LLC for the funding of 9 California peaker facilities, of which \$100.0 million was drawn on May 24, 2002 and \$50.0 million was repaid on August 7, 2002. At December 31, 2002, there was \$50.0 million outstanding under this agreement. The interest rate at December 31, 2002, was 4.0%. The interest rate ranged from 4.0% to 5.8% during 2002. The Company has classified this financing as current as it is expected to be retired in 2003.

On August 22, 2002, the Company completed a \$106.0 million non-recourse project financing for the construction of its 300-megawatt Blue Spruce Energy Center. At December 31, 2002, the Company had \$83.5 million in funded borrowings under this non-recourse construction and term-loan facility. The interest rate at December 31, 2002, was 6.3%. The interest rate ranged from 6.3% to 10.2% during 2002. This project financing will mature in 2008.

In December 2002 the Company completed a \$50.0 million project financing secured by the Newark Power Plant. At December 31, 2002, the Company had \$50.0 million in funded borrowings under this project financing. The interest rate at December 31, 2002, was 10.6%. This project financing will mature in 2014.

In December 2002 the Company completed a \$37.0 million project financing secured by the Parlin Power Plant. At December 31, 2002, the Company had \$37.0 million in funded borrowings under this project financing. The interest rate at December 31, 2002, was 9.8%. This project financing will mature in 2010.

## **17. Convertible Senior Notes Due 2006**

In December 2001 and January 2002 the Company completed the issuance of \$1.2 billion in aggregate principal amount of 4% Convertible Senior Notes Due 2006 ("Convertible Senior Notes"). These securities are convertible, at the option of the holder, into shares of Calpine common stock at a price of \$18.07. Holders have the right to require the Company to repurchase all or a portion of the Convertible Senior Notes on December 26, 2004, at 100% of their principal amount plus any accrued and unpaid interest. The Company has the right to repurchase the convertible senior notes with cash, shares of Calpine common stock, or a combination of cash and stock.

The effective interest rate on these notes, after amortization of deferred financing costs, was approximately 4.9% in 2002 and 4.4% in 2001.

## 18. Senior Notes

Senior Notes payable consist of the following as of December 31, 2002 and 2001, (in thousands):

	Interest Rates	First Call Date	December 31,		(3) Fair Value as of December 31,	
			2002	2001	2002	2001
Senior Notes Due 2004 . . . .	9 <sup>1</sup> / <sub>4</sub> %	1999	\$ —	\$ —	\$ —	\$ —
Senior Notes Due 2005 . . . .	8 <sup>1</sup> / <sub>4</sub> %	(2)	249,420	249,197	117,227	223,032
Senior Notes Due 2006 . . . .	10 <sup>1</sup> / <sub>2</sub> %	2001	171,750	171,750	82,440	163,163
Senior Notes Due 2006 . . . .	7 <sup>5</sup> / <sub>8</sub> %	(1)	249,821	249,821	107,423	221,092
Senior Notes Due 2007 . . . .	8 <sup>3</sup> / <sub>4</sub> %	2002	275,107	275,112	118,296	244,849
Senior Notes Due 2007 . . . .	8 <sup>3</sup> / <sub>4</sub> %	(2)	125,782	124,568	55,973	110,866
Senior Notes Due 2008 . . . .	7 <sup>7</sup> / <sub>8</sub> %	(1)	379,689	399,094	155,672	355,194
Senior Notes Due 2008 . . . .	8 <sup>1</sup> / <sub>2</sub> %	(2)	2,027,859	2,027,455	892,258	1,774,023
Senior Notes Due 2008 . . . .	8 <sup>3</sup> / <sub>8</sub> %	(2)	183,509	155,868	67,898	143,399
Senior Notes Due 2009 . . . .	7 <sup>3</sup> / <sub>4</sub> %	(1)	329,593	349,810	135,133	304,335
Senior Notes Due 2010 . . . .	8 <sup>5</sup> / <sub>8</sub> %	(2)	707,036	749,174	304,025	655,527
Senior Notes Due 2011 . . . .	8 <sup>1</sup> / <sub>2</sub> %	(2)	1,875,571	1,996,081	806,496	1,756,551
Senior Notes Due 2011 . . . .	8 <sup>7</sup> / <sub>8</sub> %	(2)	319,664	288,531	115,079	259,677
Total . . . . .			<u>\$6,894,801</u>	<u>\$7,036,461</u>	<u>\$2,957,920</u>	<u>\$6,211,708</u>

(1) Not redeemable prior to maturity.

(2) Redeemable at any time prior to maturity.

(3) Represents the market values of the Senior Notes at the respective dates.

The Company has completed a series of public debt offerings since 1994. Interest is payable semiannually at specified rates. Deferred financing costs are amortized on a straight-line basis, which approximates the effective interest method, over the respective lives of the notes. 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, 2002, the Company was in compliance with all debt covenants relating to the Senior Notes. The effective interest rates for each of the Company's Senior Notes outstanding at December 31, 2002, are consistent with the respective notes outstanding during 2001, unless otherwise noted.

During the third quarter of 2001, the Company borrowed a total of \$1.2 billion under three bridge credit facilities (which ranked equally with Senior Notes) to finance several acquisitions. These facilities were refinanced with the October 2001 issuance of long-term Senior Notes. The Company recorded a pre-tax loss of \$1.0 million, related to the write off of unamortized deferred financing costs.

In October 2002, \$88.4 million was paid by Pengrowth Corporation's purchase in the open market and delivery to the Company of \$203.2 million in aggregate principal amount of certain of the Company's Senior Notes. The Company recorded a pre-tax gain, net of write-off of unamortized deferred financing costs, of US\$114.8 million related to these purchases. See Note 12 for more details regarding this transaction.

The following debt securities were delivered to the Company by Pengrowth Corporation (in millions):

<u>Debt Security</u>	<u>Principal Amount</u>
7 <sup>7</sup> / <sub>8</sub> % Senior Notes Due 2008.....	\$ 19.6
7 <sup>3</sup> / <sub>4</sub> % Senior Notes Due 2009.....	20.2
8 <sup>5</sup> / <sub>8</sub> % Senior Notes Due 2010.....	42.3
8 <sup>1</sup> / <sub>2</sub> % Senior Notes Due 2011.....	<u>121.1</u>
Total .....	<u>\$203.2</u>

#### ***Senior Notes Due 2004***

Interest on these notes is payable semi-annually on February 1 and August 1 each year. The notes, which would have matured on February 1, 2004, were redeemable, at the option of the Company, at any time on or after February 1, 1999, at various redemption prices. The effective interest rate, after amortization of deferred financing costs, was 9.6% per annum. On June 7, 2001, the Company redeemed all \$105.0 million principal amount of the Senior Notes Due 2004 for 100% of the principal amount plus accrued interest to the redemption date. The Company recorded a pre-tax loss of \$1.3 million, in connection with this redemption.

#### ***Senior Notes Due 2005***

Interest on these notes is payable semi-annually on February 15 and August 15. The notes mature on August 15, 2005, or 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, after amortization of deferred financing costs, is 8.7% per annum.

#### ***Senior Notes Due 2006***

Interest on the 10<sup>1</sup>/<sub>2</sub>% notes is payable semi-annually on May 15 and November 15 each year and the notes mature on May 15, 2006, or 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, after amortization of deferred financing costs, is 10.8% per annum.

Interest on the 7<sup>5</sup>/<sub>8</sub>% notes is payable semi-annually on April 15 and October 15 each year and the notes mature on April 15, 2006, and are not redeemable prior to maturity. The effective interest rate, after amortization of deferred financing costs, is 7.9% per annum.

#### ***Senior Notes Due 2007***

Interest on the \$275.1 million principal senior notes is payable semi-annually on January 15 and July 15 each year. These notes mature on July 15, 2007, or 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, after amortization of deferred financing costs, is 9.1% per annum.

Interest on the C\$200.0 million (US\$125.8 million as of December 31, 2002) Senior Notes Due 2007 is payable semi-annually on April 15 and October 15 each year. The Notes mature on October 15, 2007; however, they may be redeemed prior to maturity, at any time in whole or from time to time in part, at a redemption price equal to the greater of (a) the "Discounted Value" of the senior notes, which equals the sum of the present values of all remaining scheduled payments of principal and interest, or (b) 100% of the principal amount plus accrued and unpaid interest to the redemption date. The Notes are fully and unconditionally guaranteed by the Company. The effective interest rate, after amortization of deferred financing costs and the effect of cross currency swaps, was 9.1% per annum.

### ***Senior Notes Due 2008***

Interest on the 7<sup>7</sup>/<sub>8</sub>% notes is payable semi-annually on April 1 and October 1 each year. These notes mature on April 1, 2008, and are not redeemable prior to maturity. The effective interest rate, after amortization of deferred financing costs, is 8.0% per annum. The Notes are fully and unconditionally guaranteed by the Company.

Interest on the 8<sup>1</sup>/<sub>2</sub>% Senior Notes is payable semi-annually on May 1 and November 1 each year. The notes mature on May 1, 2008, or may be redeemed prior to maturity at a redemption price equal to 100% of the principal amount plus accrued and unpaid interest plus a make-whole premium. The effective interest rate, after amortization of deferred financing costs, is 8.7% per annum at December 31, 2001, and 8.8% per annum at December 31, 2002.

Interest on the 8<sup>3</sup>/<sub>8</sub>% Senior Notes is payable semi-annually on April 15 and October 15 each year and the notes mature on October 15, 2008, or may be redeemed prior to maturity at a redemption price equal to 100% of the principal amount plus accrued and unpaid interest plus a make-whole premium. The effective interest rate, after amortization of deferred financing costs and the effect of cross currency swaps, was 8.8% per annum at December 31, 2001, and 9.5% per annum at December 31, 2002.

### ***Senior Notes Due 2009***

Interest on these notes is payable semi-annually on April 15 and October 15 each year. The notes mature on April 15, 2009, and are not redeemable prior to maturity. The effective interest rate, after amortization of deferred financing costs, is 7.9% per annum.

### ***Senior Notes Due 2010***

Interest on these notes is payable semi-annually on August 15 and February 15 each year, and the notes mature on August 15, 2010, and 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, after amortization of deferred financing costs, is 8.8% per annum.

### ***Senior Notes Due 2011***

Interest on the 8<sup>1</sup>/<sub>2</sub>% Senior Notes is payable semi-annually on February 15 and August 15 each year, and the notes mature on February 15, 2011, and may be redeemed prior to maturity at a redemption price equal to 100% of the principal amount plus accrued and unpaid interest plus a make-whole premium. The effective interest rate, after amortization of deferred financing costs, is 8.6% per annum at December 31, 2001, and 8.7% per annum at December 31, 2002.

Interest on the 8<sup>7</sup>/<sub>8</sub>% Senior Notes is payable semi-annually on April 15 and October 15 each year, and the notes mature on October 15, 2011, and may be redeemed prior to maturity at a redemption price equal to 100% of the principal amount plus accrued and unpaid interest plus a make-whole premium. The effective interest rate, after amortization of deferred financing costs and the effect of cross currency swaps, was 9.3% per annum at December 31, 2001, and 8.9% per annum at December 31, 2002.

### ***Annual Debt Maturities and Minimum Sublease Rentals***

The annual principal maturities of notes payable and borrowings under lines of credit, project financing, Convertible Senior Notes Due 2006, senior notes and capital lease obligations as of December 31, 2002, are as follows (in thousands):

2003 .....	\$ 1,651,496
2004 .....	3,449,548
2005 .....	277,075
2006 .....	1,649,402
2007 .....	441,192
Thereafter .....	<u>6,645,092</u>
Total .....	<u>\$14,113,805</u>

The Company intends to refinance or extend the maturity of the debt maturing in 2003. Other options include obtaining additional financing, further delaying its construction program to conserve cash, and selling assets. While the Company's ability to refinance this indebtedness will depend, in part, on events beyond its control, the Company believes it will be successful in meeting its obligations on this debt.

The Company has power sales agreements for the Broad River and Pasadena facilities that are accounted for as leases. The minimum sublease rentals to be received by the Company in connection with these agreements are \$23.7 million, \$24.1 million, \$24.4 million, \$24.7 million, and \$25.1 million for the years 2003 through 2007, respectively. Minimum sublease rentals for 2008 and thereafter are \$313.2 million.

### **19. 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 ("HIGH TIDES") at a value of \$50.00 per share.

	<u>Issue Date</u>	<u>Shares</u>	<u>Interest Rate</u>	<u>Balance December 31, 2002</u>	<u>Balance December 31, 2001</u>	<u>Conversion Ratio — Number of Common Shares per 1 High Tide</u>	<u>First Redemption Date</u>	<u>Initial Redemption Price</u>
High Tides I .....	October 1999	5,520,000	5.75%	\$ 268,608	\$ 268,346	3.4620	November 5, 2002	101.440%
High Tides II .....	January and February 2000	7,200,000	5.50%	351,499	351,177	1.9524	February 5, 2003	101.375%
High Tides III .....	August 2000	10,350,000	5.00%	503,862	503,401	1.1510	August 5, 2003	101.250%
		<u>23,070,000</u>		<u>\$1,123,969</u>	<u>\$1,122,924</u>			

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 have liquidation values of \$50.00 per share, or \$1.2 billion in total for all of the issuances. 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. Additionally, the HIGH TIDES may be redeemed at any time on or after the initial redemption date. The redemption price declines to 100% during the one year following the initial redemption date.

## 20. Provision for Income Taxes

The jurisdictional components of income (loss) before provision for income taxes at December 31, 2002, 2001, and 2000, are as follows (in thousands):

	<u>2002</u>	<u>2001</u>	<u>2000</u>
U.S. ....	\$ 85,884	\$918,886	\$529,486
International .....	<u>(55,888)</u>	<u>(33,910)</u>	<u>34,768</u>
Income before provision for income taxes .....	<u>\$ 29,996</u>	<u>\$884,976</u>	<u>\$564,254</u>

The provision (benefit) for income taxes for the years ended December 31, 2002, 2001, and 2000, consists of the following (in thousands):

	<u>2002</u>	<u>2001</u>	<u>2000</u>
Current:			
Federal .....	\$(39,402)	\$182,936	\$214,169
State .....	3,837	43,511	40,596
Foreign .....	<u>5,898</u>	<u>5,810</u>	<u>—</u>
Total Current .....	(29,667)	232,257	254,765
Deferred:			
Federal .....	96,016	98,661	(34,011)
State .....	13,398	(16,863)	(7,852)
Foreign .....	<u>(98,843)</u>	<u>(15,390)</u>	<u>18,549</u>
Total Deferred .....	<u>10,571</u>	<u>66,408</u>	<u>(23,314)</u>
Total provision (benefit) .....	<u>\$ (19,096)</u>	<u>\$298,665</u>	<u>\$231,451</u>

The Company's effective rate for income taxes for the years ended December 31, 2002, 2001, and 2000, differs from the United States statutory rate, as reflected in the following reconciliation:

	<u>2002</u>	<u>2001</u>	<u>2000</u>
United States statutory tax rate .....	35.0%	35.0%	35.0%
State income tax, net of federal benefit .....	37.3	2.0	3.8
Depletion and other permanent items .....	(0.2)	0.0	0.0
Foreign tax at rates other than U.S. statutory .....	<u>(135.8)</u>	<u>(3.3)</u>	<u>2.2</u>
Effective income tax rate .....	<u>(63.7)%</u>	<u>33.7%</u>	<u>41.0%</u>

The components of the deferred income taxes, net as of December 31, 2002 and 2001, are as follows (in thousands):

	<u>2002</u>	<u>2001</u>
Net operating loss and credit carryforwards .....	\$ 109,500	\$ 35,341
Taxes related to risk management activities and SFAS 133 .....	103,604	66,549
Other differences .....	197,609	38,146
Valuation allowance .....	<u>(26,665)</u>	<u>—</u>
Deferred tax assets .....	<u>384,048</u>	<u>140,036</u>
Property differences .....	(1,321,445)	(1,025,048)
Other differences .....	<u>(186,332)</u>	<u>(66,845)</u>
Deferred tax liabilities .....	<u>(1,507,777)</u>	<u>(1,091,893)</u>
Net deferred income taxes .....	<u>\$ (1,123,729)</u>	<u>\$ (951,857)</u>

The net operating loss consists of federal and state carryforwards of \$22.1 million which expire between 2004 and 2014. The federal and state net operating loss carryforwards available are subject to limitations on annual usage. We also have loss carryforwards in certain foreign subsidiaries, resulting in tax benefits of approximately \$87.4 million, the majority of which expire by 2008. The Company has provided a valuation allowance to reduce deferred tax assets to the extent necessary to result in an amount that is more likely than not of being realized. Realization of the deferred tax assets and 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 Company's foreign subsidiaries had no cumulative undistributed earnings at December 31, 2002.

## **21. 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 employer profit-sharing contributions of 3% of employees' salaries up to \$5,100 per year, made entirely in cash. Effective January 1, 2002, the Company increased its profit sharing contribution to 4% of employees' salaries up to \$8,000 per year. Employer profit-sharing contributions in 2002, 2001, and 2000 totaled \$11.6 million, \$6.9 million, and \$2.9 million, respectively.

### ***2000 Employee Stock Purchase Plan***

The Company adopted the 2000 Employee Stock Purchase Plan ("ESPP") in May 2000. Eligible employees may in the aggregate purchase up to 12,000,000 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 31, 2010. Under the ESPP, 2,611,597 and 1,124,851 shares were issued at a weighted average fair value of \$5.72 and \$21.05 per share in 2002 and 2001, respectively. 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 APB Opinion No. 25, "Accounting for Stock Issued to Employees" under which no compensation cost has been recognized. See Note 3 for the effects the SIP would have on the Company's financial statements if stock-based compensation was accounted for under SFAS No. 123.

For the year ended December 31, 2002, the Company had granted options to purchase 8,997,720 shares of common stock. Over the life of the SIP, options exercised have equaled 4,362,064, leaving 24,712,390 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.

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.

Changes in options outstanding, granted, exercisable and canceled during the years 2002, 2001, and 2000, under the option plans of Calpine and Encal were as follows:

	<u>Available for Option or Award</u>	<u>Outstanding Number of Options</u>	<u>Weighted Average Exercise Price</u>
Outstanding January 1, 2000 .....	5,183,284	30,965,589	3.11
Additional shares reserved .....	2,522,157	—	—
Granted .....	(4,429,289)	4,429,289	23.08
Exercised .....	—	(4,533,946)	1.85
Cancelled .....	<u>188,871</u>	<u>(188,871)</u>	17.52
Outstanding December 31, 2000 .....	<u>3,465,023</u>	<u>30,672,061</u>	6.09
Additional shares reserved .....	2,837,150	—	—
Granted .....	(3,034,014)	3,034,014	42.89
Exercised .....	—	(5,745,505)	8.64
Cancelled .....	270,006	(270,006)	34.20
Cancelled options available for award(1) .....	<u>(682,216)</u>	<u>—</u>	—
Outstanding December 31, 2001 .....	<u>2,855,949</u>	<u>27,690,564</u>	\$ 9.32
Additional shares reserved .....	15,070,588		
Granted .....	(8,997,720)	8,997,720	7.20
Exercised .....	—	(5,113,485)	0.77
Cancelled .....	1,470,802	(1,470,802)	26.53
Cancelled options available for award(1) .....	<u>(237,580)</u>	<u>—</u>	—
Outstanding December 31, 2002 .....	<u>10,162,039</u>	<u>30,103,997</u>	9.30
Options exercisable:			
December 31, 2000 .....		18,980,332	2.68
December 31, 2001 .....		18,642,381	3.81

(1) Represents cessation of options awarded under the Encal stock option plan

The following tables summarizes information concerning outstanding and exercisable options at December 31, 2002:

<u>Range of Exercise Prices</u>	<u>Number of Options Outstanding</u>	<u>Weighted Average Remaining Contractual Life in Years</u>	<u>Weighted Average Exercise Price</u>	<u>Number of Options Exercisable</u>	<u>Weighted Average Exercise Price</u>
\$ 0.570 - \$ 0.615 .....	3,088,464	1.97	\$ 0.597	3,088,464	\$ 0.597
\$ 0.645 - \$ 2.150 .....	4,508,453	4.29	1.609	4,503,253	1.609
\$ 2.195 - \$ 2.250 .....	1,698,900	4.29	2.249	1,698,900	2.249
\$ 2.345 - \$ 3.860 .....	3,942,560	6.01	3.751	3,000,010	3.717
\$ 4.010 - \$ 5.240 .....	3,642,367	9.39	5.172	209,511	4.441
\$ 5.330 - \$ 7.640 .....	4,459,961	8.11	7.568	1,933,341	7.490
\$ 7.750 - \$13.850 .....	3,789,893	6.83	10.599	2,246,128	10.001
\$13.917 - \$48.150 .....	4,774,793	6.92	31.256	2,654,747	27.287
\$48.188 - \$56.920 .....	196,606	8.23	51.428	82,243	51.412
\$56.990 - \$56.990 .....	<u>2,000</u>	8.33	56.990	<u>750</u>	56.990
\$ 0.570 - \$56.990 .....	<u>30,103,997</u>	6.22	\$ 9.299	<u>19,417,347</u>	\$ 7.140

## 22. Stockholders' Equity

### *Common Stock*

*Increase in Authorized Shares* — On July 26, 2001, the Company filed amended certificates with the Delaware Secretary of State to increase the number of authorized shares of common stock to 1,000,000,000 from 500,000,000.

*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.

On April 30, 2002, Calpine completed a registered offering of 66,000,000 shares of common stock at \$11.50 per share. The proceeds from this offering, after underwriting fees, were \$734.3 million.

### *Preferred Stock and Preferred Share Purchase Rights*

On June 5, 1997, Calpine adopted a stockholders' rights plan to strengthen Calpine's ability to protect Calpine's stockholders. The plan was amended on September 19, 2001. The rights plan is designed to protect against abusive or coercive takeover tactics that are not in the best interests of Calpine or its stockholders. To implement the rights plan, Calpine declared a dividend of one preferred share purchase right for each outstanding share of Calpine's common stock held on record as of June 18, 1997, and directed the issuance of one preferred share purchase right with respect to each share of Calpine's common stock that shall become outstanding thereafter until the rights become exercisable or they expire as described below. On December 31, 2002, there were 380,816,132 rights outstanding. Each right initially represents a contingent right to purchase, under certain circumstances, one one-thousandth of a share, called a "unit," of Calpine's Series A Participating Preferred Stock, par value \$.001 per share, at a price of \$140.00 per unit, subject to adjustment. The rights become exercisable and trade independently from Calpine's common stock upon the public announcement of the acquisition by a person or group of 15% or more of Calpine'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 Calpine's common stock. Each unit 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 Calpine's liquidation, each share of the participating preferred stock will be entitled to any payment made per share of common stock.

If Calpine is acquired in a merger or other business combination transaction after a person or group has acquired 15% or more of Calpine's common stock, each right will entitle its holder to purchase at the right's exercise price a number of the acquiring company's shares of common stock having a market value of twice the right's exercise price. In addition, if a person or group acquires 15% or more of Calpine'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 Calpine's participating preferred stock or shares of Calpine's common stock having a market value of twice the right's exercise price.

The rights remain exercisable for up to 90 days following a triggering event (such as a person acquiring 15% or more of the Company's common Stock). The rights expire on June 18, 2007, unless redeemed earlier by Calpine. Calpine can redeem the rights at a price of \$.01 per right at any time before the rights become exercisable, and thereafter only in limited circumstances.

### ***Comprehensive Income (Loss)***

Comprehensive income is the total of net income and all other non-owner changes in equity. Comprehensive income includes the Company's net income, unrealized gains and losses from derivative instruments that qualify as cash flow hedges and the effects of foreign currency translation adjustments. The Company reports Accumulated Other Comprehensive Income (AOCI) in its consolidated balance sheet. The tables below detail the changes during 2002, 2001 and 2000 in the Company's AOCI balance and the components of the Company's comprehensive income (in thousands):

	<u>Cash Flow Hedges(1)</u>	<u>Foreign Currency Translation</u>	<u>Total Accumulated Other Comprehensive Income (Loss)</u>	<u>Comprehensive Income (Loss)</u>
Accumulated other comprehensive loss at January 1, 2000 .....	\$ —	\$(19,337)	\$ (19,337)	
Net income .....				\$ 369,084
Foreign currency translation loss .....		<u>(6,026)</u>	<u>(6,026)</u>	<u>(6,026)</u>
Total comprehensive income .....				<u>\$ 363,058</u>
Accumulated other comprehensive loss at December 31, 2000 .....	<u>\$ —</u>	<u>\$(25,363)</u>	<u>\$ (25,363)</u>	
Net income .....				\$ 623,492
Cash flow hedges:				
Comprehensive pre-tax loss on cash flow hedges before reclassification adjustment .....	\$(171,400)			
Reclassification adjustment for gain included in net income .....	(126,009)			
Income tax benefit .....	<u>116,590</u>			
	(180,819)		(180,819)	(180,819)
Foreign currency translation loss .....		<u>(34,698)</u>	<u>(34,698)</u>	<u>(34,698)</u>
Total comprehensive income .....				<u>\$ 407,975</u>
Accumulated other comprehensive loss at December 31, 2001 .....	<u>\$(180,819)</u>	<u>\$(60,061)</u>	<u>\$(240,880)</u>	

	<u>Cash Flow Hedges(1)</u>	<u>Foreign Currency Translation</u>	<u>Total Accumulated Other Comprehensive Income (Loss)</u>	<u>Comprehensive Income (Loss)</u>
Net income .....				\$ 118,618
Cash flow hedges:				
Comprehensive pre-tax gain on cash flow hedges before reclassification adjustment .....	96,905			
Reclassification adjustment for gain included in net income .....	(169,205)			
Income tax benefit .....	<u>28,705</u>			
	<u>(43,595)</u>		(43,595)	(43,595)
Foreign currency translation gain .....		<u>47,018</u>	<u>47,018</u>	<u>47,018</u>
Total comprehensive income .....				<u>\$ 122,041</u>
Accumulated other comprehensive loss at December 31, 2002 .....	<u>\$(224,414)</u>	<u>\$(13,043)</u>	<u>\$(237,457)</u>	

(1) Includes accumulated other comprehensive income (loss) from cash flow hedges held by unconsolidated investees. At December 31, 2002 and 2001, these amounts were \$12,018 and \$(1,984) respectively.

### 23. Customers

In 2002, the California Department of Water Resources ("DWR") was a significant customer and accounted for more than 10% of the Company's annual consolidated revenues. In 2001, Enron was a significant customer. PG&E was a significant customer in 2001 as well as in 2000. Significant customers relate exclusively to the Electric Generation and Marketing segment, with the exception of \$33.3 million from Enron, which was derived from Oil and Gas Production and Marketing in 2001.

Revenues earned from the significant customers for the years ended December 31, 2002, 2001, and 2000, were as follows (in thousands):

	<u>2002</u>	<u>2001</u>	<u>2000</u>
<b>Revenues:</b>			
DWR .....	\$754,191	\$ *	\$ *
PG&E(1) .....	*	723,062	624,458
Enron .....	*	1,671,737	*

Receivables due from the significant customers at December 31, 2002 and 2001, were as follows (in thousands):

	<u>2002</u>	<u>2001</u>
<b>Receivables:</b>		
PG&E Accounts Receivable(2) .....	*	46,545
PG&E Notes Receivable(3) .....	*	<u>117,698</u>
PG&E Total .....	<u>\$ *</u>	<u>\$164,243</u>
Enron Accounts Receivable .....	\$ *	\$ 75,002
DWR .....	\$78,842	\$ *

\* Customer not significant in respective year.

(1) See Note 28 for further discussion of the California energy situation.

- (2) In addition to the accounts receivable shown in the table, the Company had a receivable of \$224.2 million from the sale of the pre-bankruptcy petition PG&E receivables on December 31, 2001. This receivable was collected from an escrow account in January 2002.
- (3) Payments of the PG&E notes receivable are scheduled from February 2003 to September 2014. The first scheduled note repayment of \$1.7 million was received in February 2003. See Note 10 for further discussion.

### ***California Department of Water Resources***

In 2001, California adopted legislation permitting it to issue long-term revenue bonds to fund wholesale purchases of power by the DWR. The bonds will be repaid with the proceeds of payments by retail power customers over time. CES and DWR entered into four long-term supply contracts during 2001. The Company has recorded deferred revenue in connection with one of the long-term power supply contracts (Contract 3). All of the Company's accounts receivables from DWR are current.

In early 2002, the California Public Utilities Commission ("CPUC") and the California Electricity Oversight Board ("EOB") filed complaints under Section 206 of the Federal Power Act with the Federal Energy Regulatory Commission ("FERC") alleging that the prices and terms of the long-term contracts with DWR were unjust and unreasonable and contrary to the public interest (the "206 Complaint"). The contracts entered into by CES and DWR were subject to the 206 Complaint.

On April 22, 2002, the Company announced that it had renegotiated CES' long-term power contracts with DWR and settled the 206 Complaint. The Office of the Governor, the CPUC, the EOB and the Attorney General for the State of California all endorsed the renegotiated contracts and dropped all pending claims against the Company and its affiliates, including any efforts by the CPUC and the EOB to seek refunds from the Company and its affiliates through the FERC California Refund Proceedings. In connection with the renegotiation, the Company agreed to pay \$6 million over three years to the Attorney General to resolve any and all possible claims. A summary of the material terms of the four DWR contracts, as renegotiated, follows:

(1) *Contract 1* provides for baseload power deliveries of 350 megawatts for 2002, 600 megawatts for 2003, and 1,000 megawatts for 2004 through 2009 at a fixed energy price of \$58.60 per megawatt-hour. In addition, Calpine provides up to 2.7 million and 4.8 million megawatt hours of additional, flexible energy in 2002 and 2003, respectively; with energy pricing indexed to gas and a two-year fixed capacity payment.

(2) *Contract 2* provides for baseload power deliveries of 200 megawatts for the first half of 2002 and 1,000 megawatts from July 1, 2002 through 2009 at a fixed energy price of \$59.60 per megawatt-hour. Calpine provides up to 1.7 million and 3.0 million megawatt hours of additional, flexible energy in 2002 and 2003, respectively; with energy pricing indexed to gas and a two-year fixed capacity payment. DWR has the right to complete four Calpine projects planned for California if Calpine does not meet certain milestones with respect to each project. However, if DWR exercises this right, DWR must reimburse Calpine for all construction costs and certain other costs incurred to date in connection with the project(s) being completed by DWR and this right has no effect on the prices, terms and conditions associated with the energy products being sold to DWR under Contract 2.

(3) *Contract 3* provides DWR with a 10-year option for 2,000 hours (annually) for 495 megawatts of peak power in exchange for fixed annual capacity payments of \$90 million for years one through five and \$80 million per year thereafter. If DWR exercises its option, the energy price paid is indexed to gas.

(4) *Contract 4* provides DWR up to 225 megawatts of new peaking capacity for a 3-year term, beginning with commercial operation of the Los Esteros Energy Center, for fixed annual average capacity payments and an energy price indexed to gas.

***California Electric Power Fund.*** In November 2002, the DWR completed the issuance of \$11.3 billion in revenue bonds. Part of the proceeds from this bond issuance was used to fund the Electric Power Fund (the "Fund"), which will be used to meet DWR's payment obligations under its long-term energy contracts. Revenue requirements for the repayment of the bonds will be determined at least annually and submitted to

the CPUC. Under the terms of a Rate Agreement between the DWR and the CPUC, the CPUC is required to set rates for the customers of the State's investor owned utilities ("IOUs"), such that the Fund will always have monies to retire the bonds when due. DWR is shifting certain power procurement responsibilities to the IOUs, other than those procurement obligations already committed under the terms of its long-term contracts, such as the four long-term contracts with CES discussed above. Ultimately, the financial responsibility for the long-term contracts may be transferred to the IOUs; such as, Pacific Gas and Electric Company; however, this will not occur until a number of issues are addressed, including IOU creditworthiness.

### ***Enron***

During 2001 the Company, primarily through its CES subsidiary, transacted a significant volume of business with units of Enron, mainly Enron Power Marketing, Inc. ("EPMI") and Enron North America Corp. ("ENA"). ENA is the parent corporation of EPMI. Enron is the direct parent corporation of ENA. Most of these transactions were contracts for sales and purchases of power and gas for hedging purposes, the terms of which extended out as far as 2009. On December 2, 2001, Enron Corp. and certain of its subsidiaries, including EPMI and ENA, filed voluntary petitions for Chapter 11 reorganization with the U.S. Bankruptcy Court for the Southern District of New York.

The Company has conducted no business with EPMI or ENA since December 31, 2001. The Company has terminated all of its open forward positions with ENA and EPMI, and will settle with ENA and EPMI based on the value of the terminated contracts at the termination or replacement date, as applicable.

On November 14, 2001, CES, ENA and EPMI entered into a Master Netting, Setoff and Security Agreement (the "Netting Agreement"). The Netting Agreement permits CES, on the one hand, and ENA and EPMI, on the other hand, to set off amounts owed to each other under an ISDA Master Agreement between CES and ENA, an Enfolio Master Firm Purchase/Sale Agreement between CES and ENA and a Master Energy Purchase/Sale Agreement between CES and EPMI (in each case, after giving effect to the netting provisions contained in each of these agreements).

The Company reserved \$17.9 million related to unrealized mark to market gains generated by Enron's insolvency, which caused earnings recognition for contracts that had previously been exempted from SFAS No. 133 accounting and which caused cash flow hedges to cease to be effective and mark to market in earnings until termination.

The Company believes, based on contractually permissible calculation methodologies, that its gross exposure to Enron and its affiliates will be significantly less than amounts previously disclosed during the year using calculations made under generally accepted accounting principles. The Company expects that this amount will be offset by CES' losses, damages, attorneys' fees and other expenses arising from the default by Enron.

The Company is engaged in confidential settlement negotiations with Enron, ENA and EPMI. It is premature to characterize these negotiations at this time. In the event settlement negotiations prove unsuccessful, the Company intends to pursue its rights under its agreements with Enron and its affiliates. Regardless of the outcome, the Company believes, based upon legal analysis, that it does not have any net collection exposure to Enron and its affiliates as of the date hereof.

### ***PG&E***

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 herein 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. On July 12, 2001, the U.S. Bankruptcy Court for the Northern District of California approved the agreement the Company had entered into with PG&E to modify and assume all of Calpine's QF contracts with PG&E. Under the terms of the agreement, the Company will

continue to receive its contractual capacity payments plus a five-year fixed energy price component that averages 5.37 cents per kilowatt-hour in lieu of the short run avoided cost. In addition, all past due receivables under the QF contracts were elevated to administrative priority status to be paid to the Company, with interest, upon the effective date of a confirmed plan of reorganization. On September 20, 2001, PG&E filed its proposed plan of reorganization with the bankruptcy court.

As of April 6, 2001, the date of PG&E's bankruptcy filing, the Company had recorded \$265.6 million in accounts receivable with PG&E under the QF contracts, plus \$68.7 million in notes receivable not yet due and payable. PG&E has paid currently for power delivered after April 6, 2001.

In December 2001 the bankruptcy court approved an agreement between Calpine and PG&E providing that PG&E repay the \$265.6 million in past due pre-petition receivables plus accrued interest (\$10.3 million through December 31, 2001) thereon beginning on December 31, 2001, and with monthly payments thereafter over the next 11 months. Shortly following receipt of this bankruptcy court approval and the first payments from PG&E on December 31, 2001, the Company sold the remaining PG&E receivables to a third party at a \$9.0 million discount. The cash for the sale of the receivables was collected in January 2002.

*CPUC Proceeding Regarding QF Contract Pricing for Past Periods.* The Company's QF contracts with PG&E provide that the CPUC has the authority to determine the appropriate utility "avoided cost" to be used to set energy payments for certain QF contracts by determining the short run avoided cost ("SRAC") energy price formula. In mid 2000 the Company's QF facilities elected the option set forth in Section 390 of the California Public Utility Code, which provides QFs the right to elect to receive energy payments based on the California Power Exchange ("PX") market clearing price instead of the price determined by SRAC. Having elected such option, the Company was 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. 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 at one point issued a proposed decision to the effect that the PX Price was the appropriate price for energy payments under the California Public Utility Code but tabled it, and 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.

The Company had a combined accounts receivable balance of \$21.1 million as of December 31, 2002, from the California Independent System Operator Corporation ("CAISO") and Automated Power Exchange, Inc. ("APX"). Of this balance, \$9.4 million relates to past due balances prior to the PG&E bankruptcy filing. The Company expects that a portion of these past due receivables will be offset against refund obligations under FERC's California Refund Proceedings (See Note 28) and the Company has provided a partial reserve for these past due receivables. 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 directly impacted by PG&E's ability to pay the PX, which in turn would pay APX for energy delivered by the Company through APX. As noted above, the PX ceased operating in January 2001. See Note 28 for an update on the FERC investigation into the western markets.

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

During the first quarter of 2002, two subsidiaries of Sierra Pacific Resources Company, Nevada Power Company ("NPC") and Sierra Pacific Power Company ("SPPC"), received credit downgrades to sub-investment grades from the major credit rating agencies. Additionally, NPC acknowledged liquidity problems created when the Public Utilities Commission of Nevada disallowed a rate adjustment requested by NPC to cover the increased cost of buying power during the 2001 energy crisis. NPC requested that its power suppliers extend payment terms to help it overcome its short-term liquidity problems. In June and July 2002 NPC underpaid the Company by approximately \$4.2 million. In addition, NPC and SPPC filed a complaint with the Federal Energy Regulatory Commission ("FERC") under Section 206 of the Federal Power Act — see Note 26 for further discussion. In September, 2002, NPC notified the Company of its intention to repay all

outstanding payables owed to the Company for power deliveries made during the period of May 1, 2002 through September 15, 2002, following execution by the Company of an agreement to forebear from taking action against NPC provided NPC makes certain periodic payments. On October 25, 2002, the Company received approximately \$22.2 million from NPC as repayment of past due amounts for power deliveries through September 15, 2002.

As of December 31, 2002, the Company had net collection exposures of approximately \$4.8 million and \$3.7 million with NPC and SPPC, respectively, net of established reserve. Both NPC and SPPC are paying the Company currently. The Company's exposures include open forward power contracts that are reported at fair value on the Company's balance sheet as well as receivable and payable balances relating to prior power deliveries. Management is continuing to monitor the exposure and its effect on the Company's financial condition. The table below details the components of the Company's exposure position at December 31, 2002 (in millions of dollars). The positive net positions represent realization exposure while the negative net positions represent the Company's existing or potential obligations.

	Receivables/Payables			Fair Values			Total
	Gross Receivable	Gross Payable	Net Receivable (Payable)	Gross Fair Value (+)	Gross Fair Value (-)	Net Open Positions Value	
NPC .....	\$5.5	\$(4.4)	\$1.1	\$6.4	\$(2.7)	\$3.7	\$4.8
SPPC .....	3.7	—	3.7	—	—	—	3.7
Total .....	<u>\$9.2</u>	<u>\$(4.4)</u>	<u>\$4.8</u>	<u>\$6.4</u>	<u>\$(2.7)</u>	<u>\$3.7</u>	<u>\$8.5</u>

Under the terms of its contracts with NPC and SPPC, the Company believes that it has the right to offset asset and liability positions.

***NRG Power Marketing, Inc.***

The Company has open contract positions with NRG Power Marketing, Inc., a subsidiary of NRG Energy, Inc., which in turn is the unregulated power-generation subsidiary of XCEL Energy Inc. Almost all of the open contracts are accounted for as cash flow hedges under SFAS No. 133. NRG Energy, Inc. has reported that it is experiencing financial problems, defaulted on certain loan payments and has had its long-term debt rating downgraded to D by Standard & Poor's. According to a report published on November 8, 2002, NRG Energy, Inc. has discussed a Chapter 11 bankruptcy filing with its lenders. While NRG Power Marketing, Inc. has remained current in its payments to the Company, the Company has established partial reserves totaling \$3.9 million offsetting revenue and Other Accumulated Comprehensive Loss. The Company will continue to closely monitor its position with NRG Power Marketing, Inc. and will adjust the value of the reserve as conditions dictate. The Company's exposure, net of the established reserve, to NRG Power Marketing, Inc. at December 31, 2002, is summarized below (in millions):

	Receivables/Payables			Open Positions			Total
	Gross Receivable	Gross Payable	Net Receivable (Payable)	Gross Fair Value (+)	Gross Fair Value (-)	Net Open Positions Value	
NRG Power Marketing, Inc .....	\$2.6	\$(0.4)	\$2.2	\$5.2	\$(2.0)	\$3.2	\$5.4

***Aquila Merchant Services, Inc.***

On November 13, 2002 Aquila Inc. ("Aquila"), the parent of Aquila Merchant Services, Inc., ("AMS"), reported third quarter 2002 losses of approximately \$332 million, suspended its dividend and disclosed that it had obtained debt covenant waivers expiring in April 2003 from certain of its lenders. The Company believes that a downgrade in Aquila's credit rating could trigger additional collateral requirements under Aquila's and AMS's contractual commitments. The Company currently buys and sells electricity and natural gas from Aquila and AMS under a variety of contractual arrangements. The Company accounts for certain of its contractual arrangements with AMS as derivatives under SFAS No. 133 and, accordingly, record the fair value of the open positions under these contracts in the financial statements. The Company also has

tolling arrangements with AMS on the Acadia facility and with Aquila on the Aries facility under which they deliver gas to, and purchase electricity from, the Company with 20 and 15.5 year terms, respectively. These tolling agreements are not subject to derivative accounting. While Aquila and AMS has remained current in its payments to the Company, the Company has established partial reserves totaling \$2.6 million offsetting revenue and Other Accumulated Comprehensive Loss. The Company will continue to closely monitor its position with Aquila and AMS and will adjust the value of the reserve as conditions dictate. The Company's exposure, net of the established reserve, to Aquila and AMS at December 31, 2002, is summarized below (in millions):

	Receivables/Payables			Open Positions			Total
	Gross Receivable	Gross Payable	Net Receivable (Payable)	Gross Fair Value (+)	Gross Fair Value (-)	Net Open Positions Value	
AMS and Aquila .....	\$15.0	\$(26.9)	\$(11.9)	\$90.0	\$(38.0)	\$52.0	\$40.1

Among the long term power contracts the Company entered into in California in 2001, one had a 10.5 year term, and one had a five year term. Each contract was negotiated in early 2001, commenced on July 1, 2001, and provided for pricing at \$115/megawatt-hour during the first six months which included the peak summer season of 2001 when natural gas costs were very high and blackouts were feared. The contracts then provided for a flat fixed price of \$61.00 and \$75.25, respectively, per megawatt-hour for the balance of the contract terms, when gas prices were expected to return to more normal levels. The Company concluded that each contract contained two separate elements (1. the six-month period in 2001; and 2. the period commencing January 1, 2002), and consequently the Company accounted for each element separately. Had the Company concluded that each contract contained only one element, the Company would have calculated an average price for the contract as a whole and recognized revenue on a straight-line basis. The impact of the latter approach would have been approximately \$55 million less revenue (\$36 million less net income) in 2001, and \$55 million more revenue (\$36 million more net income) in the aggregate over the balance of the contracts. Market circumstances were unique at the time these two contracts were executed, and accordingly, the Company does not anticipate that it will enter into contracts with similar characteristics in the future in which elements would be separated in the same manner.

### Credit Evaluations

The Company's treasury department includes a credit group focused on monitoring and managing counterparty risk. The credit group monitors the net exposure with each counterparty on a daily basis. The analysis is performed on a mark-to-market basis using the forward curves analyzed by the Company's Risk Controls group. The net exposure is compared against a counterparty credit risk threshold which is determined based on each counterparty's credit rating and evaluation of the financial statements. The credit department monitors these thresholds to determine the need for additional collateral or restriction of activity with the counterparty.

## 24. Derivative Instruments

### Commodity Derivative Instruments

As an independent power producer primarily focused on generation of electricity using gas-fired turbines, the Company's natural physical commodity position is "short" fuel (i.e., natural gas consumer) and "long" power (i.e., electricity seller). To manage forward exposure to price fluctuation in these and (to a lesser extent) other commodities, the Company enters into derivative commodity instruments. The Company enters into commodity instruments to convert floating or indexed electricity and gas (and to a lesser extent oil and refined product) prices to fixed prices in order to lessen its vulnerability to reductions in electric prices for the electricity it generates, to reductions in gas prices for the gas it produces, and to increases in gas prices for the fuel it consumes in its power plants. The Company seeks to "self-hedge" its gas consumption exposure to an extent with its own gas production position. Any hedging, balancing, or optimization activities that the Company engages in are directly related to the Company's asset-based business model of owning and operating gas-fired electric power plants and are designed to protect the Company's "spark spread" (the

difference between the Company's fuel cost and the revenue it receives for its electric generation). The Company hedges exposures that arise from the ownership and operation of power plants and related sales of electricity and purchases of natural gas, and the Company utilizes derivatives to optimize the returns the Company is able to achieve from these assets for the Company's shareholders. From time to time the Company has entered into contracts considered energy trading contracts under EITF Issue No. 02-3. However, the Company's traders have low capital at risk and value at risk limits for energy trading, and its risk management policy limits, at any given time, its net sales of power to its generation capacity and limits its net purchases of gas to its fuel consumption requirements on a total portfolio basis. This model is markedly different from that of companies that engage in significant commodity trading operations that are unrelated to underlying physical assets. Derivative commodity instruments are accounted for under the requirements of SFAS No. 133.

The Company also routinely enters into physical commodity contracts for sales of its generated electricity and sales of its natural gas production to ensure favorable utilization of generation and production assets. Such contracts often meet the criteria of SFAS No. 133 as derivatives but are generally eligible for the normal purchases and sales exception. Some of those contracts that are not deemed normal purchases and sales can be designated as hedges of the underlying consumption of gas or production of electricity.

In 2001 the FASB cleared SFAS No. 133 Implementation Issue No. C16 "Applying the Normal Purchases and Normal Sales Exception to Contracts That Combine a Forward Contract and a Purchased Option Contract" ("C16"). The guidance in C16 applies to fuel supply contracts that require delivery of a contractual minimum quantity of fuel at a fixed price and have an option that permits the holder to take specified additional amounts of fuel at the same fixed price at various times. Under C16, the volumetric optionality provided by such contracts is considered a purchased option that disqualifies the entire derivative fuel supply contract from being eligible to qualify for the normal purchases and normal sales exception in SFAS No. 133. On April 1, 2002, the Company adopted C16. At June 30, 2002, the Company had no fuel supply contracts to which C16 applies. However, one of the Company's equity method investees has fuel supply contracts subject to C16. The equity investee also adopted C16 in April 2002. The contracts qualified as highly effective hedges of the equity method investee's forecasted purchase of gas. Accordingly, the Company has recorded \$7.8 million net of tax as a cumulative effect of change in accounting principle to other comprehensive income for its share of the equity method investee's other comprehensive income from this accounting change.

#### ***Interest Rate and Currency Derivative Instruments***

The Company also enters into various interest rate swap agreements to hedge against changes in floating interest rates on certain of its project financing facilities. The interest rate swap agreements effectively convert floating rates into fixed rates so that the Company can predict with greater assurance what its future interest costs will be and protect itself against increases in floating rates.

In conjunction with its capital markets activities, the Company enters into various forward interest rate agreements to hedge against interest rate fluctuations that may occur after the Company has decided to issue long-term fixed rate debt but before the debt is actually issued. The forward interest rate agreements effectively prevent the interest rates on anticipated future long-term debt from increasing beyond a certain level, allowing the Company to predict with greater assurance what its future interest costs on fixed rate long-term debt will be.

The Company enters into various foreign currency swap agreements to hedge against changes in exchange rates on certain of its senior notes denominated in currencies other than the U.S. dollar. The foreign currency swaps effectively convert floating exchange rates into fixed exchange rates so that the Company can predict with greater assurance what its U.S. dollar cost will be for purchasing foreign currencies to satisfy the interest and principal payments on these senior notes.

*Summary of Derivative Values*

The table below reflects the amounts (in thousands) that are recorded as assets and liabilities at December 31, 2002, for the Company's derivative instruments:

	<u>Interest Rate Derivative Instruments</u>	<u>Currency Derivative Instruments</u>	<u>Commodity Derivative Instruments Net</u>	<u>Total Derivative Instruments</u>
Current derivative assets . . . . .	\$ —	\$ —	\$330,244	\$330,244
Long-term derivative assets . . . . .	<u>—</u>	<u>9,580</u>	<u>486,448</u>	<u>496,028</u>
Total assets . . . . .	<u>\$ —</u>	<u>\$9,580</u>	<u>\$816,692</u>	<u>\$826,272</u>
Current derivative liabilities . . . . .	\$ 14,402	\$1,189	\$173,765	\$189,356
Long-term derivative liabilities . . . . .	<u>28,481</u>	<u>7,619</u>	<u>492,300</u>	<u>528,400</u>
Total liabilities . . . . .	<u>\$ 42,883</u>	<u>\$8,808</u>	<u>\$666,065</u>	<u>\$717,756</u>
Net derivative assets (liabilities) . . . . .	<u>\$ (42,883)</u>	<u>\$ 772</u>	<u>\$150,627</u>	<u>\$108,516</u>

At any point in time, it is highly unlikely that total net derivative assets and liabilities will equal accumulated OCI, net of tax from derivatives, for three primary reasons:

- Tax effect of OCI — When the values and subsequent changes in values of derivatives that qualify as effective hedges are recorded into OCI, they are initially offset by a derivative asset or liability. Once in OCI, however, these values are tax effected against a deferred tax liability or asset account, thereby creating an imbalance between net OCI and net derivative assets and liabilities.
- Derivatives not designated as cash flow hedges and hedge ineffectiveness — Only derivatives that qualify as effective cash flow hedges will have an offsetting amount recorded in OCI. Derivatives not designated as cash flow hedges and the ineffective portion of derivatives designated as cash flow hedges will be recorded into earnings instead of OCI, creating a difference between net derivative assets and liabilities and pre-tax OCI from derivatives.
- Termination of effective cash flow hedges prior to maturity — Following the termination of a cash flow hedge, changes in the derivative asset or liability are no longer recorded to OCI. At this point, an accumulated OCI balance remains that is not recognized in earnings until the forecasted initially hedged transactions occur. As a result, there will be a temporary difference between OCI and derivative assets and liabilities on the books until the remaining OCI balance is recognized in earnings.

Below is a reconciliation of the Company's net derivative assets to its accumulated other comprehensive loss, net of tax from derivative instruments at December 31, 2002 (in thousands):

Net derivative assets . . . . .	\$ 108,516
Derivatives not designated as cash flow hedges and recognized hedge ineffectiveness . . . . .	(180,814)
Cash flow hedges terminated prior to maturity . . . . .	(310,580)
Deferred tax asset attributable to accumulated other comprehensive loss on cash flow hedges . . . . .	145,294
Accumulated OCI from unconsolidated investees . . . . .	12,018
Other reconciling items . . . . .	<u>1,152</u>
Accumulated other comprehensive loss from derivative instruments, net of tax(1) . .	<u>\$ (224,414)</u>

(1) Amount represents one portion of the Company's total accumulated OCI balance. See Note 22 for further information.

The asset and liability balances for the Company's commodity derivative instruments represent the net totals after offsetting certain assets against certain liabilities under the criteria of FASB Interpretation No. 39, "Offsetting of Amounts Related to Certain Contracts (an Interpretation of APB Opinion No. 10 and FASB Statement No. 105)" ("FIN 39"). For a given contract, FIN 39 will allow the offsetting of assets against liabilities so long as four criteria are met: (1) each of the two parties under contract owes the other determinable amounts; (2) the party reporting under the offset method has the right to set off the amount it owes against the amount owed to it by the other party; (3) the party reporting under the offset method intends to exercise its right to set off; and; (4) the right of set-off is enforceable by law. The table below reflects both the amounts (in thousands) recorded as assets and liabilities by the Company and the amounts that would have been recorded had the Company's commodity derivative instrument contracts not qualified for offsetting as of December 31, 2002.

	<b>December 31, 2002</b>	
	<u>Gross</u>	<u>Net</u>
Current derivative assets .....	\$1,287,034	\$330,244
Long-term derivative assets .....	<u>1,022,279</u>	<u>486,448</u>
Total derivative assets .....	<u>\$2,309,313</u>	<u>\$816,692</u>
Current derivative liabilities .....	\$1,130,182	\$173,765
Long-term derivative liabilities .....	<u>1,028,504</u>	<u>492,300</u>
Total derivative liabilities .....	<u>\$2,158,686</u>	<u>\$666,065</u>
Net commodity derivative assets .....	<u>\$ 150,627</u>	<u>\$150,627</u>

The table above excludes the value of interest rate and currency derivative instruments.

The tables below reflect the impact of the Company's derivative instruments on its pre-tax earnings, both from cash flow hedge ineffectiveness and from the changes in market value of derivatives not designated as hedges of cash flows, for the years ended December 31, 2002 and 2001, respectively (in thousands):

	<u>2002</u>			<u>2001</u>		
	<u>Hedge Ineffectiveness</u>	<u>Undesignated Derivatives</u>	<u>Total</u>	<u>Hedge Ineffectiveness</u>	<u>Undesignated Derivatives</u>	<u>Total</u>
Natural gas derivatives(1) ....	\$ 2,147	\$(14,792)	\$(12,645)	\$(5,788)	\$ 30,113	\$ 24,325
Power derivatives(1) .....	(4,934)	12,974	8,040	1,866	96,402	98,268
Interest rate derivatives(2) ....	<u>(810)</u>	<u>—</u>	<u>(810)</u>	<u>(1,330)</u>	<u>(5,785)</u>	<u>(7,115)</u>
Total .....	<u>\$(3,597)</u>	<u>\$ (1,818)</u>	<u>\$( 5,415)</u>	<u>\$(5,252)</u>	<u>\$120,730</u>	<u>\$115,478</u>

(1) Recorded within unrealized mark-to-market gain (loss) on power and gas transactions, net

(2) Recorded within Other Income

The table below reflects the contribution of the Company's cash flow hedge activity to pre-tax earnings based on the reclassification adjustment from OCI to earnings for the years ended December 31, 2002 and 2001, respectively (in thousands):

	<u>2002</u>	<u>2001</u>
Natural gas and crude oil derivatives .....	\$(119,419)	\$(30,745)
Power derivatives .....	304,073	163,228
Interest rate derivatives .....	(10,993)	(6,474)
Foreign currency derivatives .....	<u>(4,456)</u>	<u>—</u>
Total derivatives .....	<u>\$ 169,205</u>	<u>\$126,009</u>

As of December 31, 2002, the maximum length of time over which the Company was hedging its exposure to the variability in future cash flows for forecasted transactions was 8, 6, and 12 years, for commodity, foreign currency and interest rate derivative instruments, respectively. The Company estimates that pre-tax losses of \$(113.6) million would be reclassified from accumulated OCI into earnings during the twelve months ended December 31, 2003, as the hedged transactions affect earnings assuming constant gas and power prices, interest rates, and exchange rates over time; however, the actual amounts that will be reclassified will likely vary based on the probability that gas and power prices as well as interest rates and exchange rates will, in fact, change. Therefore, management is unable to predict what the actual reclassification from OCI to earnings (positive or negative) will be for the next twelve months.

The table below presents (in thousands) the pre-tax gains (losses) currently held in OCI that will be recognized annually into earnings, assuming constant gas and power prices, interest rates, and exchange rates over time.

	<u>2003</u>	<u>2004</u>	<u>2005</u>	<u>2006</u>	<u>2007 &amp; After</u>	<u>Total</u>
Crude oil OCI .....	\$ (510)	\$ —	\$ —	\$ —	\$ —	\$ (510)
Gas OCI .....	(87,352)	(37,929)	(58,420)	(20,441)	3,374	(200,768)
Power OCI .....	(2,003)	(21,410)	(21,055)	(13,825)	322	(57,971)
Interest rate OCI .....	(22,474)	(19,499)	(15,179)	(12,434)	(33,672)	(103,258)
Foreign currency OCI .....	(1,228)	(1,426)	(1,355)	(1,312)	(1,881)	(7,202)
Total pre-tax OCI .....	<u>\$(113,567)</u>	<u>\$(80,264)</u>	<u>\$(96,009)</u>	<u>\$(48,012)</u>	<u>\$(31,857)</u>	<u>\$(369,709)</u>

## 25. 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 convertible 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 June 8, 2000, and November 14, 2000.

	For the Years Ended December 31,								
	2002			2001			2000		
	<u>Net Income</u>	<u>Shares</u>	<u>EPS</u>	<u>Net Income</u>	<u>Shares</u>	<u>EPS</u>	<u>Net Income</u>	<u>Shares</u>	<u>EPS</u>
<b>Basic earnings per common share:</b>									
Income before discontinued operations and cumulative effect of a change in accounting principle .....	\$ 49,092	354,822	\$0.14	\$586,311	303,522	\$1.93	\$332,803	281,084	\$1.18
Discontinued operations, net of tax .....	69,526		0.19	36,145		0.12	36,281		0.13
Cumulative effect of a change in accounting principle .....	—		—	1,036		—	—		—
Net income .....	<u>\$118,618</u>	354,822	<u>\$0.33</u>	<u>\$623,492</u>	303,522	<u>\$2.05</u>	<u>\$369,084</u>	281,084	<u>\$1.31</u>
Common shares issuable upon exercise of stock options using treasury stock method ..		<u>7,711</u>			<u>14,397</u>			<u>16,423</u>	

	For the Years Ended December 31,								
	2002			2001			2000		
	Net Income	Shares	EPS	Net Income	Shares	EPS	Net Income	Shares	EPS
<b>Diluted earnings per common share:</b>									
Income before dilutive effect of certain convertible securities, discontinued operations and cumulative effect of a change in accounting principle . . . . .	\$ 49,092	362,533	\$0.14	\$586,311	317,919	\$1.84	\$332,803	297,507	\$1.12
Dilutive effect of certain convertible securities	—	—	—	46,632	54,337	(0.14)	20,841	31,746	(0.05)
Income before discontinued operations and cumulative effect of a change in accounting principle . . . . .	49,092	362,533	0.14	632,943	372,256	1.70	353,644	329,253	1.07
Discontinued operations, net of tax . . . . .	69,526		0.19	36,145		0.10	36,281		0.11
Cumulative effect of a change in accounting principle . . . . .	—		—	1,036		—	—		—
Net income, as adjusted . . . . .	<u>\$118,618</u>	<u>362,533</u>	<u>\$0.33</u>	<u>\$670,124</u>	<u>372,256</u>	<u>\$1.80</u>	<u>\$389,925</u>	<u>329,253</u>	<u>\$1.18</u>

Potentially convertible securities and unexercised employee stock options to purchase 136,744,307, 13,293,586, and 18,877,778 shares of the Company's common stock were not included in the computation of diluted shares outstanding during the years ended December 31, 2002, 2001, and 2000, respectively, because such inclusion would be anti-dilutive.

## 26. Commitments and Contingencies

*Turbines.* On February 11, 2003, the Company announced a significant restructuring of its turbine agreements (see Note 5), which enables the Company to cancel up to 131 steam and gas turbines. The Company recorded a pre-tax charge of \$207.4 million in connection with these restructurings. The Company remains committed to take delivery of 12 gas and 9 steam turbines. The table below sets forth future payments for previously delivered turbines, payments and delivery year for the remaining 21 turbines to be delivered as well as payment required for the potential cancellation costs of the 131 gas and steam turbines. The table does not include payments that would result if the Company were to release for manufacturing any of the 131 turbines.

<u>Year</u>	<u>Total</u>	<u>Units To Be Delivered</u>
2003 . . . . .	\$427,848 (1)	14
2004 . . . . .	153,339	7
2005 . . . . .	19,596	—
Total . . . . .	<u>\$600,783</u>	<u>21</u>

(1) Includes certain payments under vendor financing. See Note 16 for further discussion.

*Power Plant Operating Leases* — The Company has entered into long-term operating leases for power generating facilities, expiring through 2049. Many of the lease agreements provide for renewal options, and some of the agreements contain customary restrictions on dividends, additional debt and further encumbrances similar to those typically found in project finance instruments. In accordance with SFAS No. 13 and

SFAS No. 98, "Accounting for Leases" the Company's operating leases are not reflected on our balance sheet. Future minimum lease payments under these leases are as follows (in thousands):

	Initial Year	2003	2004	2005	2006	2007	Thereafter	Total
Watsonville .....	1995	\$ 2,905	\$ 2,905	\$ 2,905	\$ 2,905	\$ 2,905	\$ 6,969	\$ 21,494
King City .....	1996	22,563	13,746	10,344	9,700	9,100	96,150	161,603
Greenleaf .....	1998	8,994	8,858	8,723	8,650	8,650	45,628	89,503
Geysers .....	1999	66,967	55,415	55,890	47,991	47,150	183,419	456,832
KIAC .....	2000	25,467	24,251	24,077	23,875	23,845	289,092	410,607
Rumford/Tiverton .....	2000	32,940	35,365	44,942	45,000	45,000	653,292	856,539
South Point .....	2001	46,059	31,627	9,620	9,620	9,620	317,650	424,196
RockGen .....	2001	25,861	26,565	27,031	26,088	27,478	227,344	360,367
Total .....		<u>\$231,756</u>	<u>\$198,732</u>	<u>\$183,532</u>	<u>\$173,829</u>	<u>\$173,748</u>	<u>\$1,819,544</u>	<u>\$2,781,141</u>

In 2002, 2001, and 2000 rent expense for power plant operating leases amounted to \$111.0 million, \$99.5 million, and \$63.5 million, respectively. Calpine guarantees \$1.8 billion of the total future minimum lease payments of its consolidated subsidiaries.

The King City operating lease commitment is supported by collateral debt securities that mature serially in amounts equal to a portion of the semi-annual lease payment. These debt securities are classified as held-to-maturity and are recorded at an amortized cost of \$86.1 million at December 31, 2002.

*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 or adjusted based on CPI changes and are not material. Under the terms of most 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 were based on 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 that are in addition to the land base lease royalties. Some 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 for the years ended December 31, 2002, 2001, and 2000, are \$17.6 million, \$27.5 million, and \$32.3 million, respectively.

*Office and Equipment Leases* — The Company leases its corporate and regional offices as well as some of its office equipment under noncancellable operating leases expiring through 2013. Future minimum lease payments under these leases are as follows (in thousands):

2003 .....	\$ 24,028
2004 .....	28,182
2005 .....	26,377
2006 .....	22,240
2007 .....	19,743
Thereafter .....	<u>108,621</u>
Total .....	<u>\$229,191</u>

Lease payments are subject to adjustments for the Company's pro rata portion of annual increases or decreases in building operating costs. In 2002, 2001, and 2000 rent expense for noncancellable operating leases amounted to \$25.8 million, \$16.2 million, and \$6.3 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.

*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 natural gas to third parties or pay the corresponding tariffs.

*Guarantees* — As part of normal business, Calpine enters into various agreements providing, or otherwise arranges, financial or performance assurance to third parties on behalf of its subsidiaries. Such arrangements include guarantees, standby letters of credit and surety bonds. These arrangements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes.

Calpine routinely issues guarantees to third parties in connection with contractual arrangements entered into by Calpine's direct and indirect wholly-owned subsidiaries in the ordinary course of such subsidiaries' respective business, including power and natural gas purchase and sale arrangements and contracts associated with the development, construction, operation and maintenance of Calpine's fleet of power generating facilities. Under these guarantees, if the subsidiary in question were to fail to perform its obligations under the guaranteed contract, giving rise to a default and/or an amount owing by the subsidiary to the third party under the contract, Calpine could be called upon to pay such amount to the third party or, in some instances, to perform the subsidiary's obligations under the contract. It is Calpine's policy to attempt to negotiate specific limits or caps on Calpine's overall liability under these types of guarantees; however, in some instances, Calpine's liability is not limited by way of such a contractual liability cap.

At December 31, 2002, guarantees of subsidiary debt, standby letters of credit, surety bonds and guarantees of subsidiary operating lease payments and their respective expiration dates were as follows (in thousands):

<b>Commitments Expiring</b>	<b>2003</b>	<b>2004</b>	<b>2005</b>	<b>2006</b>	<b>2007</b>	<b>Thereafter</b>	<b>Total</b>
Guarantee of subsidiary debt . . .	\$161,268	\$ 18,597	\$ 13,086	\$15,528	\$152,618	\$3,035,559	\$3,396,656
Standby letters of credit(1) . . .	622,178	—	63,428	—	—	—	685,606
Surety bonds(2) . . . . .	2,090	33,366	—	—	—	36,811	72,267
Guarantee of subsidiary operating lease payments . . .	111,070	96,688	83,169	81,772	82,487	1,393,364	1,848,550
<b>Total . . . . .</b>	<b>\$896,606</b>	<b>\$148,651</b>	<b>\$159,683</b>	<b>\$97,300</b>	<b>\$235,105</b>	<b>\$4,465,734</b>	<b>\$6,003,079</b>

(1) The Standby letters of credit disclosed above include those disclosed in Notes 13 and 16.

(2) The bonds that do not have expiration or cancellation dates are included in the Thereafter column.

The balance of the guarantees of subsidiary debt, standby letters of credit and surety bonds were as follows (in thousands):

	<b>Balance at December 31,</b>	
	<b>2002</b>	<b>2001</b>
Guarantee of subsidiary debt . . . . .	\$3,396,656	\$3,283,507
Standby letters of credit . . . . .	685,606	642,496
Surety bonds . . . . .	72,267	261,937
	<b>\$4,154,529</b>	<b>\$4,187,940</b>

The Company has guaranteed the principal payment of \$2,656.8 million and \$2,596.4 million, as of December 31, 2002 and 2001, respectively, of Senior Notes for two wholly-owned finance subsidiaries of Calpine, Calpine Canada Energy Finance ULC and Calpine Canada Energy Finance II ULC. In addition, as of December 31, 2002 the Company has guaranteed the payment of \$50.0 million of project financing for its wholly-owned subsidiary, Calpine California Energy Finance, LLC. As of December 31, 2002, the Company

has guaranteed \$301.0 million and \$388.9 million, respectively, of project financing for the Broad River Energy Center and Pasadena Power Plant and \$300.0 million and \$387.1 million, respectively, as of December 31, 2000 for these power plants. All of the guaranteed debt is recorded on the Company's consolidated balance sheet.

Calpine routinely arranges for the issuance of letters of credit and various forms of surety bonds to third parties in support of its subsidiaries' contractual arrangements of the types described above and may guarantee the operating performance of some of its partially owned subsidiaries up to the Company's ownership percentage. The letters of credit outstanding under various credit facilities support CES risk management, and other operational and construction activities. Of the total letters of credit outstanding, \$106.1 million and \$236.1 million were issued to support CES risk management at December 31, 2002 and 2001, respectively. In the event a subsidiary were to fail to perform its obligations under a contract supported by such a letter of credit or surety bond, and the issuing bank or surety were to make payment to the third party, Calpine would be responsible for reimbursing the issuing bank or surety within an agreed timeframe, typically a period of 1 to 10 days. To the extent liabilities are incurred as a result of activities covered by letters of credit or the surety bonds, such liabilities are included in the consolidated balance sheets.

At December 31, 2002, investee debt was \$639.3 million. Based on the Company's ownership share of each of the investments, the Company's share would be approximately \$238.6 million. However, all such debt is non-recourse to the Company.

In the course of its business, Calpine and its subsidiaries have entered into various purchase and sale agreement relating to stock and assets. These purchase and sale agreements customarily provide for indemnification by each of the purchaser and the seller, and/or their respective parent, to the counter-party for liabilities incurred as a result of a breach of a representation or warranty by the indemnifying party. These indemnification obligations generally have a discrete term and are intended to protect the parties against risks that are difficult to predict or impossible to quantify at the time of the consummation of a particular transaction. We have no reason to believe that Calpine currently has any material liability relating to such routine indemnification obligations.

Calpine has in a few limited circumstances directly or indirectly guaranteed the performance of obligations by unrelated third parties. These circumstances have arisen in situations in which a third party has contractual obligations with respect to the construction, operation or maintenance of a power generating facility or related equipment owned in whole or in part by Calpine. Generally, the third party's obligations with respect to such facility or generating are guaranteed for the direct or indirect benefit of Calpine by the third party's parent or other party. A financing party or investor in such facility or equipment may negotiate for Calpine also to guarantee the performance of such third party's obligations as additional support for the third party's obligations. For example, in conjunction with the financing of California peaker program, Calpine guaranteed for the benefit of the lenders certain warranty obligations of third party suppliers and contractors. Calpine has entered into few guarantees of unrelated third party's obligations. Calpine has no reason to believe that currently has any liability with respect to these guarantees.

The Company believes that the likelihood that it would be required to perform or otherwise incur any significant losses associated with any of these guarantees is remote.

### ***Litigation***

The Company is party to various litigation matters arising out of the normal course of business, the more significant of which are summarized below. The ultimate outcome of each of these matters cannot presently be determined, nor can the liability that could potentially result from a negative outcome in each case presently be reasonably estimated. The liability the Company may ultimately incur with respect to any one of these matters in the event of a negative outcome may be in excess of amounts currently accrued with respect to such matters and, as a result, these matters may potentially be material to the Company's consolidated financial statements.

*Securities Class Action Lawsuits.* Fourteen shareholder lawsuits have been filed against the Company and certain of its officers in the United States District Court, Northern District of California. The actions captioned *Weisz v. Calpine Corp.*, et al., filed March 11, 2002, and *Labyrinth Technologies, Inc. v. Calpine Corp.*, et al., filed March 28, 2002, are purported class actions on behalf of purchasers of Calpine stock between March 15, 2001 and December 13, 2001. *Gustaferra v. Calpine Corp.*, filed April 18, 2002, is purported class action on behalf of purchasers of Calpine stock between February 6, 2001 and December 13, 2001. The eleven other actions were filed between March 18, 2002 and April 23, 2002. The complaints in these eleven actions are virtually identical — three law firms, in conjunction with other law firms as co-counsel, filed them. All eleven lawsuits are purported class actions on behalf of purchasers of the Company's securities between January 5, 2001 and December 13, 2001.

The complaints in these fourteen actions allege that, during the purported class periods, certain senior Calpine Executives issued false and misleading statements about the Company's financial condition in violation of Sections 10(b) and 20(1) of the Securities Exchange Act of 1934, as well as Rule 10b-5. These actions seek an unspecified amount of damages, in addition to other forms of relief.

In addition, a fifteenth securities class action, *Ser v. Calpine, et al.*, was filed on May 13, 2002. The underlying allegations in the Ser action are substantially the same as those in the above-referenced actions. However, the Ser action is brought on behalf of a purported class of purchasers of the Company's 8.5% Senior Notes due February 15, 2011 ("2011 Notes") and the alleged class period is October 15, 2001 through December 13, 2001. The Ser Complaint alleges that in violation of Sections 11 and 15 of the Securities Act of 1933, the Prospectus Supplement dated October 11, 2001, for the 2011 Notes contained false and misleading statements regarding the Company's financial condition. This action names as defendants the Company, certain of its officers and directors, and the underwriters of the 2011 Note offering as defendants, and seeks an unspecified amount of damages, in addition to other forms of relief.

All fifteen of these securities class action lawsuits were consolidated in the U.S. District Court Northern District Court of California. In January 2003, Plaintiffs filed an amended consolidated complaint naming additional officers as defendants and adding new security law claims. The Company considers these lawsuits to be without merit and intends to defend vigorously against them.

*Johnson v. Peter Cartwright, et al.* On December 17, 2001, a shareholder filed a derivative lawsuit on behalf of the Company against its directors and one of its senior officers. This lawsuit is styled *Johnson v. Cartwright, et al.* and is pending in the California Superior Court, Santa Clara County. The Company is a nominal defendant in this lawsuit, which alleges claims relating to purportedly misleading statements about the Company and stock sales by certain of the director defendants and the officer defendant. In December 2002, the court dismissed the complaint with respect to certain of the director defendants for lack of personal jurisdiction, though the plaintiff may appeal this ruling. In early February 2003, the plaintiff filed an amended complaint. The Company considers this lawsuit to be without merit and intends to vigorously defend against it.

*Gordon v. Peter Cartwright, et al.* On August 8, 2002, a shareholder filed a derivative lawsuit in the United States District Court for the Northern District of California on behalf of the Company against its directors, captioned *Gordon v. Cartwright, et al.*, similar to *Johnson v. Cartwright*. Motions have been filed to dismiss the action against certain of the director defendants on the grounds of lack of personal jurisdiction, as well as to dismiss the complaint in total on other grounds. In February 2003, the plaintiff agreed to stay these proceedings in favor of the consolidated federal securities class action described above and to dismiss without prejudice certain director defendants. The Company considers this lawsuit to be without merit and intends to vigorously defend against it.

*California Business & Professions Code Section 17200 Cases. The lead case T&E Pastorino Nursery v. Duke Energy Trading and Marketing, L.L.C., et al.* This purported class action complaint filed in May 2002 against twenty energy traders and energy companies including CES alleges that defendants exercised market power and manipulated prices in violation of California Business & Professions Code Section 17200 et seq., and seeks injunctive relief, restitution and attorneys' fees. The Company also has been named in seven other similar complaints for violations of Section 17200. All seven cases have been removed from the various state courts in which they were originally filed to federal court for pretrial proceedings with other cases in which the

Company is not named as a defendant. In addition, plaintiffs in the case have filed a motion to remand that matter to California state court.

The Company considers the allegations against Calpine and its subsidiaries in each of these lawsuits to be without merit, and intends to vigorously defend against them.

*McClintock et al. v. Vikram Budhraj, et al. California Department of Water Resources Case.* On May 1, 2002, California State Senator Tom McClintock and others filed a complaint against Vikram Budhraj, a consultant to the California Department of Water Resources (“DWR”), DWR itself, and more than twenty nine energy providers and other interested parties, including the Company. The complaint alleges that the long term power contracts that DWR entered into with these energy providers, including the Company, are rendered void because Budhraj, who negotiated the contracts on behalf of the DWR, allegedly had an undisclosed financial interest in the contracts due to his connection to one of the energy providers, Edison International. Among other things, the complaint seeks an injunction prohibiting further performance of the long-term contracts and restitution of any funds paid to energy providers by the State of California under the contracts. The action has been stayed by order of the Court since August 26, 2002, pending resolution of an earlier-filed state court action involving the same parties and subject matter captioned *Carboneau v. State of California* in which the Company is not a defendant. The Company considers the allegations against the Company in this lawsuit to be without merit and intends to vigorously defend against them.

*Nevada Power Company and Sierra Pacific Power Company v. Calpine Energy Services, L.P. before the FERC, filed on December 4, 2001. Nevada Section 206 Complaint.* On December 4, 2001, NPC and SPPC filed a complaint with FERC under Section 206 of the Federal Power Act against a number of parties to their power sales agreements, including the Company. NPC and SPPC allege in their complaint, which seeks a refund, that the prices they agreed to pay in certain of the power sales agreements, including those signed with the Company, were negotiated during a time when the power market was dysfunctional and that they are unjust and unreasonable. The Company considers the complaint to be without merit and is vigorously defending against it. The Administrative Law Judge issued an Initial Decision on December 19, 2002 that found for the Company and the other respondents in the case and denied Nevada Power the relief that it was seeking. The parties are waiting for a final FERC order in this proceeding.

*Calpine Corporation v. Automated Credit Exchange.* On March 5, 2002, the Company sued Automated Credit Exchange (“ACE”) in the Superior Court of the State of California for the County of Alameda for negligence and breach of contract to recover reclaim trading credits, a form of emission reduction credits that should have been held in the Company’s account with U.S. Trust Company (“US Trust”). The Company wrote-off \$17.7 million in December 2001 related to losses that it alleged were caused by ACE. The Company and ACE entered into a settlement agreement on March 29, 2002, pursuant to which ACE made a payment to the Company of \$7 million and transferred to the Company the rights to the emission reduction credits to be held by ACE. The Company recognized the \$7 million in the second quarter of 2002. In June 2002 a complaint was filed by InterGen North America, L.P. (“InterGen”) against Anne M. Sholtz, the owner of ACE, and EonXchange, another Sholtz-controlled entity, which filed for bankruptcy protection on May 6, 2002. InterGen alleges it suffered a loss of emission reduction credits from EonXchange in a manner similar to the Company’s loss from ACE. InterGen’s complaint alleges that Anne Sholtz co-mingled assets among ACE, EonXchange and other Sholtz entities and that ACE and other Sholtz entities should be deemed to be one economic enterprise and all retroactively included in the EonXchange bankruptcy filing as of May 6, 2002. InterGen’s complaint refers to the payment by ACE of \$7 million to the Company alleging that InterGen’s ability to recover from EonXchange has been undermined thereby. The company is unable to assess the likelihood of InterGen’s complaint being upheld at this time.

*Geysers Reliability Must Run Section 206 Proceeding.* California Independent System Operator, California Electricity Oversight Board, Public Utilities Commission of the State of California, Pacific Gas and Electric Company, San Diego Gas & Electric Company, and Southern California Edison (collectively referred to as the “Buyers Coalition”), filed a complaint on November 2, 2001 at the Federal Energy Regulatory Commission requesting the commencement of a Federal Power Act Section 206 proceeding to challenge one

component of a number of separate settlements previously reached on the terms and conditions of “reliability must-run” contracts (“RMR Contracts”) with certain generation owners, including Geysers Power Company, LLC, which settlements were also previously approved by the FERC. RMR contracts require the owner of the specific generation unit to provide energy and ancillary services when called upon to do so by the ISO to meet local transmission reliability needs or to manage transmission constraints. The Buyers Coalition has asked FERC to find that the availability payments under these RMR Contracts are not just and reasonable. Geysers Power Company, LLC filed an answer to the complaint in November 2001. To date, FERC has not established a section 206 proceeding. The outcome of this litigation and the impact on the Company’s business cannot be presently determined.

*International Paper Company v. Androscoggin Energy LLC.* In October 2000, International Paper Company filed a complaint against Androscoggin Energy LLC (“AELLC”) alleging that AELLC breached certain contractual representations and warranties by failing to disclose facts surrounding the termination, effective May 8, 1998, of one of AELLC’s fixed-cost gas supply agreements. The Company had acquired a 32.3% interest in AELLC as part of the Skygen transaction which closed in October 2000. AELLC filed a counterclaim against International Paper Company that has been referred to arbitration. AELLC may commence the arbitration counterclaim after discovery has progressed further, depending on the outcome of the discussions referred to below. On November 7, 2002, the court issued an opinion on the parties’ cross motions for summary judgment finding in AELLC’s favor on certain matters though granting summary judgment to International Paper Company on the liability aspect of a particular claim against AELLC. While the matter is expected to proceed to the damages aspect of trial in mid-2003, the Company is seeking to engage IP in discussions to explore a commercial resolution to the matter. The Company cannot currently estimate the possible loss, if any, it may ultimately incur as a result of this matter.

In addition, the Company is involved in various other legal actions proceedings, and state and regulatory investigations relating to the Company’s business. The Company is involved in various other claims and legal actions arising out of the normal course of its 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.

## **27. 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 and other activities. Electric generation and marketing includes the development, acquisition, ownership and operation of power production facilities, hedging, balancing, optimization, and trading activity transacted on behalf of the Company’s power generation facilities. 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 hedging, balancing, optimization, and trading activity transacted on behalf of the Company’s oil and gas operations. 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, such as interest expense, distributions on HIGH TIDES, and interest income, which are allocated based on a ratio of segment assets to total assets.

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 3 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, and reclassifications have been made to prior periods to present the allocation consistently.

	<u>Electric Generation and Marketing</u>	<u>Oil and Gas Production and Marketing</u>	<u>Corporate, Other and Eliminations</u>	<u>Total</u>
	(In thousands)			
<b>2002</b>				
Total Revenue . . . . .	\$ 7,146,754	\$ 301,601	\$ 9,544	\$ 7,457,899
Depreciation and amortization . . . . .	302,166	149,264	8,035	459,465
Interest expense . . . . .	331,078	30,514	52,128	413,720
Interest income . . . . .	34,529	3,182	5,437	43,148
Income before taxes . . . . .	187,095	(7,856)	(149,243)	29,996
Discontinued operations, net of tax . . . . .	24,842	44,684	—	69,526
Equity income . . . . .	16,552	—	—	16,552
Total assets . . . . .	18,587,342	1,713,085	2,926,565	23,226,992
Investments in power plants . . . . .	421,402	—	—	421,402
Property Additions . . . . .	3,274,051	413,174	349,029	4,036,254
Equipment cancellation and asset . . . . .	404,737	—	—	404,737
Intersegment revenues . . . . .	—	180,374	—	180,374
<b>2001</b>				
Total Revenue . . . . .	\$ 6,322,459	\$ 406,814	\$ 24,955	\$ 6,754,228
Depreciation and amortization . . . . .	182,871	122,265	6,166	311,302
Interest expense . . . . .	152,089	15,281	31,127	198,497
Interest income . . . . .	55,518	5,578	11,362	72,458
Income before taxes . . . . .	856,041	116,261	(87,326)	884,976
Discontinued operations, net of tax . . . . .	1,544	34,601	—	36,145
Equity income . . . . .	16,225	—	—	16,225
Total assets . . . . .	16,808,395	1,688,751	3,440,081	21,937,227
Investments in power plants . . . . .	392,711	—	—	392,711
Property Additions . . . . .	4,814,024	485,944	532,906	5,832,874
Merger costs . . . . .	—	41,627	—	41,627
Intersegment revenues . . . . .	—	123,845	—	123,845
<b>2000</b>				
Total Revenue . . . . .	\$ 2,189,799	\$ 274,153	\$ (88,774)	\$ 2,375,178
Depreciation and amortization . . . . .	112,888	82,305	670	195,863
Interest expense . . . . .	54,271	9,902	17,717	81,890
Interest income . . . . .	26,844	4,898	8,762	40,504
Income before taxes . . . . .	632,148	107,571	(175,465)	564,254
Discontinued operations, net of tax . . . . .	484	35,797	—	36,281
Equity income . . . . .	30,085	(1,289)	—	28,796
Total assets . . . . .	7,031,852	1,282,950	2,295,430	10,610,232
Investments in power plants . . . . .	156,969	47,983	—	204,952
Property Additions . . . . .	2,558,620	317,486	192,422	3,068,528
Intersegment revenues . . . . .	—	66,524	—	66,524

Intersegment revenues primarily relate to the use of internally procured gas for the Company's power plants. These intersegment revenues have been included in Total Revenue and Income before taxes in the oil and gas production and marketing reporting segment and eliminated in the corporate and other reporting segment.

### Geographic Area Information

As of December 31, 2002, the Company owned interests in 79 operating power plants in the United States, two operating power plants in Canada and one operating power plant in the United Kingdom. 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.

	<u>United States</u>	<u>Canada</u>	<u>United Kingdom</u>	<u>Total</u>
<b>2002</b>				
Total Revenue .....	\$ 7,128,107	\$123,908	\$205,884	\$ 7,457,899
Property, plant and equipment, net .....	16,962,005	925,787	963,175	18,850,967
<b>2001</b>				
Total Revenue .....	\$ 6,467,436	\$192,097	\$ 94,695	\$ 6,754,228
Property, plant and equipment, net .....	13,563,186	844,832	919,376	15,327,394
<b>2000</b>				
Total Revenue .....	\$ 2,214,408	\$160,770	\$ —	\$ 2,375,178
Property, plant and equipment, net .....	7,138,045	521,972	—	7,660,017

### 28. California Power Market

*California Refund Proceeding.* On August 2, 2000 the California Refund Proceeding was initiated by a complaint made at FERC by San Diego Gas & Electric Company and under Section 206 of the Federal Power Act, alleging, among other things, that the markets operated by the California Independent System Operator (“CAISO”) and the California Power Exchange (“CalPX”) CalPX were dysfunctional. In addition to commencing an inquiry regarding the market structure, FERC established a refund effective period of October 2, 2000 to June 19, 2001 for sales made into those markets. On June 19, 2001, FERC ordered price mitigation throughout the western United States in an attempt to reduce the dependence of the California market on spot markets in favor of longer-term committed energy supplies. Subsequently, the Chief Administrative Law Judge (“Chief ALJ”) issued his report and recommendations to FERC on July 12, 2001 on how refunds should be calculated. Based on the Chief ALJ’s report, FERC established a subsequent proceeding to determine the refund liability for each seller for a refund period of October 2, 2000 through June 19, 2001. During this refund period the Company sold much of its California merchant capacity in the bilateral markets, which sales are not subject to refund under this proceeding. As a result of an order by the U.S. Court of Appeals for the Ninth Circuit, FERC is required to consider the impact on possible market manipulation on potential refund liability. In November 2002, FERC issued an order establishing a special hundred-day period for additional discovery. In March 2003 the parties were required to submit reports addressing any such market manipulation. This aspect of the proceeding has not yet been concluded.

On December 12, 2002, the Administrative Law Judge issued a Certification of Proposed Finding on California Refund Liability making an initial determination of refund liability (the “December 12 Certification”). Under the December 12 Certification, Calpine had potential direct and indirect refund liability of approximately \$6.2 million, considering the offsets available to the Company. We have fully reserved the amount of refund liability that would potentially be owed under the December 12 Certification. See Note 29 for an update.

*FERC Investigation into Western Markets.* On February 13, 2002, FERC initiated an investigation of potential manipulation of electric and natural gas prices in the western United States. This investigation was initiated as a result of allegations that Enron and others used their market position to distort electric and natural gas markets in the West. The scope of the investigation is to consider whether, as a result of any manipulation in the short-term markets for electric energy or natural gas or other undue influence on the wholesale markets by any party since January 1, 2000, the rates of the long-term contracts subsequently entered into in the West are potentially unjust and unreasonable. FERC has stated that it may use the information gathered in connection with the investigation to determine how to proceed on any existing or

future complaint brought under Section 206 of the Federal Power Act involving long-term power contracts entered into in the West since January 1, 2000, or to initiate a Federal Power Act Section 206 or Natural Gas Act Section 5 proceeding on its own initiative. On August 13, 2002, the FERC staff issued the Initial Report on Company-Specific Separate Proceedings and Generic Reevaluations; Published Natural Gas Price Data; and Enron Trading Strategies (the "Initial Report") summarizing its initial findings in this investigation. There were no findings or allegations of wrongdoing by the Company set forth or described in the Initial Report.

### ***CPUC Proceedings***

The Company is involved from time to time in administrative litigation at the California Public Utilities Commission ("CPUC"). In addition, the Company frequently intervenes in proceedings at the CPUC where it is not a direct party to protect its interests. See Note 23 Customers for more information.

### ***City of Lodi Agreement***

On February 9, 2001, the Company entered into an agreement with the City of Lodi (the Northern California Power Agency acted as agent on behalf of the City of Lodi) whereby CES would sell 25 MW of ATC fixed price power plus a 1.7 MW day-ahead call option to the City of Lodi for delivery from January 1, 2002 through December 31, 2011. In September 2002, the City of Lodi and Calpine agreed to terminate this agreement resulting in a \$41.5 million gain. The gain is included in Other income in the accompanying consolidated financial statements.

## **29. Subsequent Events**

On February 13, 2003, the Company completed a secondary offering of 17,034,234 Warranted Units of the Calpine Power Income Fund for gross proceeds of Cdn\$153.3 million (US\$100.2 million). The Warranted Units were sold to a syndicate of underwriters at a price of Cdn\$9.00. Each Warranted Unit consists of one Trust Unit and one-half of one Trust Unit purchase warrant. Each Warrant entitles the holder to purchase one Trust Unit at a price of Cdn\$9.00 per Trust Unit at any time on or prior to December 30, 2003, after which time the Warrant will be null and void. Assuming the exercise in full of the Warrants, Calpine will not own or control any of the outstanding Trust Units. However, Calpine will retain its 30% subordinated interest in the Canadian power generating assets and will continue to operate and manage the Calpine Power Income Fund and the Fund assets.

A sixteenth securities class action, *Hawaii Structural Ironworkers Pension Fund v. Calpine, et al.*, was filed on March 11, 2003 against the Company, its directors and certain investment banks in the California Superior Court, San Diego County. The underlying allegations in the Hawaii Structural Ironworkers Pension Fund action ("Hawaii action") are substantially the same as those in the above-referenced actions. However, the Hawaii action is brought on behalf of a purported class of purchasers of the Company's equity securities sold to public investors in the Company's April 2002 equity offering. The Hawaii action alleges that the Registration Statement and Prospectus filed by the Company which became effective on April 24, 2002 contained false and misleading statements regarding the Company's financial condition in violation of Sections 11, 12 and 15 of the Securities Act of 1933. The Hawaii action relies in part on the Company's restatement of certain past financial results, announced on March 3, 2003, to support its allegations. The Hawaii action seeks an unspecified amount of damages, in addition to other forms of relief. The Company considers this lawsuit to be without merit and intends to defend vigorously against it.

On March 26, 2003, the staff of the FERC issued a final report in an investigation the FERC had initiated on February 13, 2002 of potential manipulation of electric and natural gas prices in the western United States (the "Final Report"). The FERC staff recommended that FERC issue a show cause order to a number of companies, including Calpine, regarding certain power scheduling practices that may potentially be in violation of the CAISO's or CalPX' tariff. The Company believes that it did not violate these tariffs and that, to the extent that such a finding could be made, any potential liability would not be material. The Final

Report also recommended that FERC modify the basis for determining potential liability in the California Refund Proceeding discussed above.

On March 26, 2003, FERC also issued an order adopting many of the ALJ's findings set forth in the December 12 Certification (the "March 26 Order"). See Note 28 for a discussion of the December 12 Certification. In addition, as a result of certain findings by the FERC staff concerning the unreliability or misreporting of certain reported indices for gas prices in California during the refund period, FERC ordered that the basis for calculating a party's potential refund liability be modified by substituting a gas proxy price based upon gas prices in the producing areas plus the tariff transportation rate for the California gas price indices previously adopted in the refund proceeding. At this time, the Company is unable to determine its potential liability under the March 26 Order. However, based upon a preliminary understanding, the Company believes that such liability is likely to increase from that calculated in accordance with the December 12 Certification, but the Company is unable to estimate the amount of such potential increase at this time.

The final outcome of this proceeding and the impact on the Company's business is uncertain at this time.

### **30. 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, the degree of risk management and trading activity, and variations in levels of production. Furthermore, the majority of the dollar value 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 1,849 common stockholders of record at December 31, 2002. No dividends were paid for the years ended December 31, 2002 and 2001. All share data has been adjusted to reflect the two-for-one stock split effective June 8, 2000, and the two-for-one stock split effective November 14, 2000.

The quarterly operating results below include both the amounts as originally reported in prior periods and the amounts as restated. See Note 2 for further information on the restatement of prior period financial statements.

	Quarter Ended			
	December 31,	September 30,	June 30,	March 31,
	(In thousands, except per share amounts)			
<b>2002, Restated (for periods through September 30, 2002)</b>				
Total revenue .....	\$1,888,763	\$2,476,228	\$1,760,373	\$1,332,535
Gross profit .....	237,504	349,806	248,236	181,394
Income (loss) from operations .....	(74,602)	275,066	169,229	(55,994)
Income before discontinued operations ..	(66,637)	133,712	59,435	(77,718)
Discontinued operations, net of tax .....	41,179	17,416	8,886	2,045
Net income (loss) .....	\$ (25,158)	\$ 151,128	\$ 68,321	\$ (75,673)
Basic earnings per common share:				
Income (loss) before discontinued operations .....	\$ (0.18)	\$ 0.35	\$ 0.17	\$ (0.25)
Discontinued operations, net of tax ...	0.11	0.05	0.02	—
Net income (loss) .....	(0.07)	0.40	0.19	(0.25)
Diluted earnings per common share:				
Income (loss) before discontinued operations and dilutive effect of certain trust preferred securities ....	\$ (0.18)	\$ 0.35	\$ 0.16	\$ (0.25)
Dilutive effect of certain trust preferred securities .....	—	(0.04)	—	—
Income (loss) before discontinued operations .....	(0.18)	0.31	0.16	(0.25)
Discontinued operations, net of tax ...	0.11	0.03	0.02	—
Net income (loss) .....	(0.07)	0.34	0.18	(0.25)
Common stock price per share:				
High .....	\$ 4.69	\$ 7.29	\$ 13.55	\$ 17.28
Low .....	1.55	2.36	5.30	6.15

	Quarter Ended			
	December 31,	September 30,	June 30,	March 31,
	(In thousands, except per share amounts)			
<b>2002, As Reported</b>				
Total revenue .....	\$1,888,763	\$2,495,010	\$1,941,806	\$1,738,347
Gross profit .....	237,504	362,332	256,306	177,964
Income (loss) from operations .....	(74,602)	277,416	177,992	(62,106)
Income (loss) before discontinued operations and extraordinary gain (loss) .....	(66,637)	144,397	72,516	(76,397)
Discontinued operations, net of tax .....	41,179	16,950	—	—
Extraordinary gain (loss), net of tax .....	—	—	—	2,130
Net income (loss) .....	\$ (25,158)	\$ 161,347	\$ 72,516	\$ (74,267)
Basic earnings per common share:				
Income (loss) before discontinued operations and extraordinary gain (loss) .....	\$ (0.18)	\$ 0.38	\$ 0.20	\$ (0.25)
Discontinued operations, net of tax .....	0.11	0.05	—	—
Extraordinary gain (loss), net of tax .....	—	—	—	0.01
Net income (loss) .....	(0.07)	0.43	0.20	(0.24)
Diluted earnings per common share:				
Income (loss) before discontinued operations, extraordinary gain (loss) and dilutive effect of certain trust preferred securities .....	\$ (0.18)	\$ 0.38	\$ 0.20	\$ (0.25)
Dilutive effect of certain trust preferred securities .....	—	(0.05)	(0.01)	—
Income (loss) before discontinued operations and extraordinary gain (loss) .....	(0.18)	0.33	0.19	(0.25)
Discontinued operations, net of tax .....	0.11	0.03	—	—
Extraordinary gain (loss), net of tax .....	—	—	—	0.01
Net income (loss) .....	(0.07)	0.36	0.19	(0.24)
Common stock price per share:				
High .....	\$ 4.69	\$ 7.29	\$ 13.55	\$ 17.28
Low .....	1.55	2.36	5.30	6.15

	Quarter Ended			
	December 31,	September 30,	June 30,	March 31,
(In thousands, except per share amounts)				
<b>2001, Restated</b>				
Total revenue .....	\$1,469,104	\$2,506,860	\$1,491,997	\$1,286,267
Gross profit .....	212,285	505,126	279,649	236,435
Income from operations .....	165,009	483,369	191,190	178,810
Income before discontinued operations and cumulative effect of a change in accounting principle .....	93,943	307,710	92,546	92,112
Discontinued operations, net of tax .....	2,529	7,314	10,857	15,445
Cumulative effect of a change in accounting principle .....	—	—	—	1,036
Net income .....	\$ 96,472	\$ 315,024	\$ 103,403	\$ 108,593
Basic earnings per common share:				
Income before discontinued operations and cumulative effect of a change in accounting principle .....	\$ 0.31	\$ 1.01	\$ 0.31	\$ 0.31
Discontinued operations, net of tax ...	0.01	0.02	0.03	0.05
Cumulative effect of a change in accounting principle .....	—	—	—	—
Net income .....	0.32	1.03	0.34	0.36
Diluted earnings per common share:				
Income before dilutive effect of certain convertible securities, discontinued operations and cumulative effect of a change in accounting principle .....	\$ 0.30	\$ 0.97	\$ 0.29	\$ 0.29
Dilutive effect of certain convertible securities .....	(0.02)	(0.11)	(0.01)	(0.01)
Income before discontinued operations and cumulative effect of a change in accounting principle .....	0.28	0.86	0.28	0.28
Discontinued operations, net of tax ...	0.01	0.02	0.03	0.05
Cumulative effect of a change in accounting principle .....	—	—	—	—
Net income .....	0.29	0.88	0.31	0.33
Common stock price per share:				
High .....	\$ 28.85	\$ 46.00	\$ 57.35	\$ 58.04
Low .....	10.00	18.90	36.20	29.00

	Quarter Ended			
	December 31,	September 30,	June 30,	March 31,
	(In thousands, except per share amounts)			
<b>2001, As Reported</b>				
Total revenue . . . . .	\$1,721,249	\$2,520,151	\$1,612,873	\$1,339,751
Gross profit . . . . .	215,836	521,145	304,225	275,568
Income (loss) from operations . . . . .	164,192	486,894	213,710	217,623
Income (loss) before discontinued operations, extraordinary gain (loss) and cumulative effect of a change in accounting principle . . . . .	92,671	313,496	108,965	118,627
Discontinued operations, net of tax . . . . .	—	7,303	—	—
Extraordinary gain (loss), net of tax . . . . .	7,307	—	(1,300)	—
Cumulative effect of a change in accounting principle . . . . .	—	—	—	1,036
Net income (loss) . . . . .	\$ 99,978	\$ 320,799	\$ 107,665	\$ 119,663
Basic earnings per common share:				
Income (loss) before discontinued operations, extraordinary gain (loss) and cumulative effect of a change in accounting principle . . . . .	\$ 0.30	\$ 1.03	\$ 0.36	\$ 0.39
Discontinued operations, net of tax . . . . .	—	0.02	—	—
Extraordinary gain (loss), net of tax . . . . .	0.03	—	—	—
Cumulative effect of a change in accounting principle . . . . .	—	—	—	0.01
Net income (loss) . . . . .	0.33	1.05	0.36	0.40
Diluted earnings per common share:				
Income (loss) before discontinued operations, extraordinary gain (loss), cumulative effect of a change in accounting principle and dilutive effect of certain trust preferred securities . . . . .	\$ 0.29	\$ 0.98	\$ 0.34	\$ 0.37
Dilutive effect of certain trust preferred securities . . . . .	(0.01)	(0.12)	(0.02)	(0.02)
Income (loss) before discontinued operations, extraordinary gain (loss) and cumulative effect of a change in accounting principle . . . . .	0.28	0.86	0.32	0.35
Discontinued operations, net of tax . . . . .	—	0.02	—	—
Extraordinary gain (loss), net of tax . . . . .	0.02	—	—	—
Cumulative effect of a change in accounting principle . . . . .	—	—	—	0.01
Net income (loss) . . . . .	0.30	0.88	0.32	0.36
Common stock price per share:				
High . . . . .	\$ 28.85	\$ 46.00	\$ 57.35	\$ 58.04
Low . . . . .	10.00	18.90	36.20	29.00

## INDEPENDENT AUDITORS' REPORT

To the Board of Directors and Stockholders of  
Calpine Corporation

We have audited the consolidated financial statements of Calpine Corporation and subsidiaries as of December 31, 2002 and 2001 and for each of the three years in the period ended December 31, 2002, and have issued our report thereon dated March 10, 2003 (March 26, 2003 as to paragraphs two, three and four of Note 29), which report expresses an unqualified opinion and includes an explanatory paragraph as to the restatement of the 2001 and 2000 consolidated financial statements and an emphasis paragraph relating to the adoption of new accounting standards; such consolidated financial statements and report are included elsewhere in this Form 10-K. Our audits also included the consolidated financial statement schedules of Calpine Corporation, listed in Item 15. These consolidated financial statement schedules are the responsibility of Calpine Corporation's management. Our responsibility is to express an opinion based on our audits. In our opinion, such consolidated financial statement schedules, when considered in relation to the basic consolidated financial statements taken as a whole, present fairly in all material respects the information set forth therein.

/s/ DELOITTE & TOUCHE LLP

San Jose, California

March 10, 2003 (March 26, 2003 as to paragraphs two, three and four of Note 29)

SCHEDULE II

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS

<u>Description</u>	<u>Balance at Beginning of Year</u>	<u>Charged to Expense</u>	<u>Charged to Accumulated Other Comprehensive Loss</u>	<u>Reserved Gain</u>	<u>Reductions(1)</u>	<u>Balance at End of Year</u>
			(In thousands)			
Year Ended December 31, 2002						
Allowance for Doubtful Accounts . . . . .	\$15,422	\$ 1,547	\$ —	\$ —	\$(11,014)	\$ 5,955
Gross reserve for California Refund Liability . . . . .	—	10,700	—	—	—	10,700
Reserve for derivative assets . . . . .	1,583	17,253	8,444	—	(10,828)	16,452
Gain reserved on certain Enron transactions . . . .	17,862	—	—	—	—	17,862
Reserve for third-party default on emission reduction credits . . . . .	17,677	—	—	—	(17,677)	—
Deferred tax asset valuation allowance . . . . .	—	26,665	—	—	—	26,665
Year Ended December 31, 2001						
Allowance for Doubtful Accounts . . . . .	\$11,555	\$11,539	\$ —	\$ —	\$ (7,672)	\$15,422
Reserve for Notes Receivable . . . . .	2,920	—	—	—	(2,920)	—
Reserve for derivative assets . . . . .	—	23	1,560	—	—	1,583
Gain reserved on certain Enron transactions . . . .	—	—	—	17,862	—	17,862
Reserve for third-party default on emission reduction credits . . . . .	—	17,677	—	—	—	17,677
Year Ended December 31, 2000						
Allowance for Doubtful Accounts . . . . .	\$ 3,646	\$12,190	\$ —	\$ —	\$ (4,281)	\$11,555
Reserve for Notes Receivable . . . . .	2,920	—	—	—	—	2,920

(1) Represents write-offs of accounts considered to be uncollectible and 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 expected 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 as of December 31, 2002 and 2001, were based on estimates made by Netherland, Sewell & Associates Inc. (“NSA”), independent petroleum consultants, for reserves in the United States; and Gilbert Laustsen Jung Associates Ltd. (“GLJ”), independent petroleum consultants, for reserves in Canada.

Estimates of proved and proved developed reserves as of December 31, 2000, were based on estimates made by NSA for reserves in the United States; and GLJ and McDaniel & Associates Consultants, Ltd., both independent petroleum consultants, for reserves in Canada.

Market prices as of each year-end were used for future sales of natural gas, crude oil and natural gas liquids. 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.

**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, 2002, 2001 and 2000, (in thousands):

	<u>2002</u>	<u>2001</u>	<u>2000</u>
Proved properties .....	\$1,668,626	\$1,913,025	\$1,339,938
Unproved properties .....	<u>305,639</u>	<u>322,735</u>	<u>76,075</u>
Total .....	1,974,265	2,235,760	1,416,013
Less — Accumulated depreciation, depletion and amortization .....	<u>(525,700)</u>	<u>(519,747)</u>	<u>(337,922)</u>
Net capitalized costs .....	<u>\$1,448,565</u>	<u>\$1,716,013</u>	<u>\$1,078,091</u>

**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, 2002, 2001, and 2000, (in thousands):

	<u>United States</u>	<u>Canada</u>	<u>Total</u>
December 31, 2002 —			
Acquisition costs of properties —			
Proved .....	\$ 9,763	\$ 2,650	\$ 12,413
Unproved .....	<u>8,460</u>	<u>1,694</u>	<u>10,154</u>
Subtotal .....	18,223	4,344	22,567
Exploration costs .....	10,958	7,559	18,517
Development costs .....	<u>54,986</u>	<u>61,209</u>	<u>116,195</u>
Total .....	<u>\$ 84,167</u>	<u>\$ 73,112</u>	<u>\$157,279</u>
December 31, 2001 —			
Acquisition costs of properties —			
Proved .....	\$342,941	\$ 6,762	\$349,703
Unproved .....	<u>234,789</u>	<u>17,780</u>	<u>252,569</u>
Subtotal .....	577,730	24,542	602,272
Exploration costs .....	20,495	17,970	38,465
Development costs .....	<u>86,311</u>	<u>162,343</u>	<u>248,654</u>
Total .....	<u>\$684,536</u>	<u>\$204,855</u>	<u>\$889,391</u>
December 31, 2000 —			
Acquisition costs of properties —			
Proved .....	\$101,618	\$307,356	\$408,974
Unproved .....	<u>1,119</u>	<u>71,141</u>	<u>72,260</u>
Subtotal .....	102,737	378,497	481,234
Exploration costs .....	4,100	62,469	66,569
Development costs .....	<u>26,233</u>	<u>90,820</u>	<u>117,053</u>
Total .....	<u>\$133,070</u>	<u>\$531,786</u>	<u>\$664,856</u>

### *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, 2002, 2001, and 2000, (in thousands):

	<u>United States</u>	<u>Canada</u>	<u>Total</u>
December 31, 2002 —			
Oil and gas production revenues —			
Third-party . . . . .	\$40,035	\$ 61,067	\$101,102
Intercompany . . . . .	<u>136,562</u>	<u>62,844</u>	<u>199,406</u>
Total revenues . . . . .	176,597	123,911	300,508
Exploration expenses, including dry hole . . . . .	10,287	2,797	13,084
Production costs . . . . .	37,329	42,304	79,633
Depreciation, depletion and amortization . . . . .	<u>80,314</u>	<u>67,400</u>	<u>147,714</u>
Income before income taxes . . . . .	48,667	11,410	60,077
Income tax provision . . . . .	18,980	5,438	24,418
(Income)/loss after income taxes from discontinued operations . . . . .	<u>13</u>	<u>(15,762)</u>	<u>(15,749)</u>
Results of operations . . . . .	<u>\$29,674</u>	<u>\$ 21,734</u>	<u>\$ 51,408</u>
December 31, 2001 —			
Oil and gas production revenues —			
Third-party . . . . .	\$92,622	\$194,452	\$287,074
Intercompany . . . . .	<u>112,171</u>	<u>3,730</u>	<u>115,901</u>
Total revenues . . . . .	204,793	198,182	402,975
Exploration expenses, including dry hole . . . . .	4,311	9,284	13,595
Production costs . . . . .	28,518	40,645	69,163
Depreciation, depletion and amortization . . . . .	<u>58,915</u>	<u>62,082</u>	<u>120,997</u>
Income before income taxes . . . . .	113,049	86,171	199,220
Income tax provision . . . . .	40,513	41,069	81,582
(Income)/loss after income taxes from discontinued operations . . . . .	<u>(117)</u>	<u>(38,009)</u>	<u>(38,126)</u>
Results of operations . . . . .	<u>\$72,653</u>	<u>\$ 83,111</u>	<u>\$155,764</u>
December 31, 2000 —			
Oil and gas production revenues —			
Third-party . . . . .	\$45,421	\$176,570	\$221,991
Intercompany . . . . .	<u>62,809</u>	<u>—</u>	<u>62,809</u>
Total revenues . . . . .	108,230	176,570	284,800
Exploration expenses, including dry hole . . . . .	1,836	13,824	15,660
Production costs . . . . .	15,806	33,162	48,968
Depreciation, depletion and amortization . . . . .	<u>29,983</u>	<u>50,836</u>	<u>80,819</u>
Income before income taxes . . . . .	60,605	78,748	139,353
Income tax provision . . . . .	23,583	36,072	59,655
(Income)/loss after income taxes from discontinued operations . . . . .	<u>112</u>	<u>(38,929)</u>	<u>(38,817)</u>
Results of operations . . . . .	<u>\$36,910</u>	<u>\$ 81,605</u>	<u>\$118,515</u>

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 three years in the period ended December 31, 2002, 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.

	<u>United States</u>	<u>Canada</u>	<u>Total</u>
<b>Natural gas (Bcf) (1) —</b>			
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 .....	<u>(25)</u>	<u>(52)</u>	<u>(77)</u>
Net proved reserves at December 31, 2000 .....	333	537	870
Revisions of previous estimates .....	(24)	(49)	(73)
Purchases in place .....	208	—	208
Extensions, discoveries and other additions .....	125	31	156
Sales in place .....	(11)	(13)	(24)
Production .....	<u>(41)</u>	<u>(61)</u>	<u>(102)</u>
Net proved reserves at December 31, 2001 .....	590	445	1,035
Revisions of previous estimates .....	(23)	(1)	(24)
Purchases in place .....	—	—	—
Extensions, discoveries and other additions .....	64	22	86
Sales in place .....	(3)	(119)	(122)
Production .....	<u>(53)</u>	<u>(46)</u>	<u>(99)</u>
Net proved reserves at December 31, 2002 .....	<u>575</u>	<u>301</u>	<u>876</u>
<b>Natural gas liquids and crude oil (MBbl) (2) (3) —</b>			
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 .....	<u>(240)</u>	<u>(5,202)</u>	<u>(5,442)</u>
Net proved reserves at December 31, 2000 .....	3,539	46,661	50,200
Revisions of previous estimates .....	(238)	(1,492)	(1,730)
Purchases in place .....	1,116	450	1,566
Extensions, discoveries and other additions .....	671	2,243	2,914
Sales in place .....	(80)	(3,054)	(3,134)
Production .....	<u>(434)</u>	<u>(6,192)</u>	<u>(6,626)</u>

	<u>United States</u>	<u>Canada</u>	<u>Total</u>
Net proved reserves at December 31, 2001 .....	4,574	38,616	43,190
Revisions of previous estimates .....	265	782	1,047
Purchases in place .....	—	—	—
Extensions, discoveries and other additions .....	191	819	1,010
Sales in place .....	(347)	(23,620)	(23,967)
Production .....	<u>(574)</u>	<u>(3,704)</u>	<u>(4,278)</u>
Net proved reserves at December 31, 2002 .....	<u>4,109</u>	<u>12,893</u>	<u>17,002</u>
<b>(Bcfe) (1) equivalent(4) —</b>			
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 .....	<u>(27)</u>	<u>(84)</u>	<u>(111)</u>
Net proved reserves at December 31, 2000 .....	355	816	1,171
Revisions of previous estimates .....	(25)	(58)	(83)
Purchases in place .....	214	3	217
Extensions, discoveries and other additions .....	129	45	174
Sales in place .....	(12)	(32)	(44)
Production .....	<u>(44)</u>	<u>(97)</u>	<u>(141)</u>
Net proved reserves at December 31, 2001 .....	617	677	1,294
Revisions of previous estimates .....	(21)	4	(17)
Purchases in place .....	—	—	—
Extensions, discoveries and other additions .....	65	27	92
Sales in place .....	(5)	(261)	(266)
Production .....	<u>(56)</u>	<u>(69)</u>	<u>(125)</u>
Net proved reserves at December 31, 2002 .....	<u>600</u>	<u>378</u>	<u>978</u>
<b>Net proved developed reserves</b>			
<b>Natural gas (Bcf) (1) —</b>			
December 31, 2000 .....	268	391	659
December 31, 2001 .....	378	394	772
December 31, 2002 .....	378	262	640
<b>Natural gas liquids and crude oil (MBbl) (2) (3) —</b>			
December 31, 2000 .....	2,567	32,929	35,496
December 31, 2001 .....	2,719	34,131	36,850
December 31, 2002 .....	2,509	11,623	14,132
<b>Bcf(1) equivalents(4) —</b>			
December 31, 2000 .....	283	588	871
December 31, 2001 .....	394	599	993
December 31, 2002 .....	393	332	725

(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's oil and gas assets.

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. Income tax expense, for both the United States and Canada, has been computed using expected future tax rates and giving effect to tax deductions and credits available, under current laws, and which relate to oil and gas producing activities.

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, 2002, 2001, and 2000, (in millions):

	<u>United States</u>	<u>Canada</u>	<u>Total</u>
December 31, 2002 —			
Future cash inflows . . . . .	\$2,798	\$1,569	\$4,367
Future production and development costs . . . . .	<u>(852)</u>	<u>(435)</u>	<u>(1,287)</u>
Future net cash flows before income taxes . . . . .	1,946	1,134	3,080
Future income taxes . . . . .	<u>(548)</u>	<u>(379)</u>	<u>(927)</u>
Future net cash flows . . . . .	1,398	755	2,153
Discount to present value at 10% annual rate . . . . .	<u>(622)</u>	<u>(272)</u>	<u>(894)</u>
Standardized measure of discounted future net cash flows relating to proved gas, natural gas liquids and crude oil reserves . . . . .	<u>\$ 776</u>	<u>\$ 483</u>	<u>\$1,259</u>
December 31, 2001 —			
Future cash inflows . . . . .	\$1,609	\$1,621	\$3,230
Future production and development costs . . . . .	<u>(602)</u>	<u>(569)</u>	<u>(1,171)</u>
Future net cash flows before income taxes . . . . .	1,007	1,052	2,059
Future income taxes . . . . .	<u>(217)</u>	<u>(245)</u>	<u>(462)</u>
Future net cash flows . . . . .	790	807	1,597
Discount to present value at 10% annual rate . . . . .	<u>(349)</u>	<u>(269)</u>	<u>(618)</u>

	<u>United States</u>	<u>Canada</u>	<u>Total</u>
Standardized measure of discounted future net cash flows relating to proved gas, natural gas liquids and crude oil reserves . . . . .	\$ 441	\$ 538	\$ 979
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 . . . . .	<u>\$1,198</u>	<u>\$1,880</u>	<u>\$3,078</u>

***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, 2002, 2001, and 2000 (in millions):

	<u>United States</u>	<u>Canada</u>	<u>Total</u>
Balance, December 31, 1999 . . . . .	\$ 153	\$ 550	\$ 703
Sales and transfers of gas, natural gas liquids and crude oil produced, net of production costs . . . . .	(93)	(245)	(338)
Net changes in prices and production costs . . . . .	985	1,717	2,702
Extensions, discoveries, additions and improved recovery, net of related costs . . . . .	131	475	606
Development costs incurred . . . . .	6	25	31
Revisions of previous quantity estimates and development costs . . . . .	102	(215)	(113)
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 . . . . .	(129)	(114)	(243)
Balance, December 31, 2000 . . . . .	\$1,198	\$1,880	\$ 3,078
Sales and transfers of gas, natural gas liquids and crude oil produced, net of production costs . . . . .	(177)	(273)	(450)
Net changes in prices and production costs . . . . .	(1,314)	(1,733)	(3,047)
Extensions, discoveries, additions and improved recovery, net of related costs . . . . .	165	70	235
Development costs incurred . . . . .	26	46	72
Revisions of previous quantity estimates and development costs . . . . .	(110)	(298)	(408)
Accretion of discount . . . . .	120	40	160
Net change in income taxes . . . . .	370	869	1,239
Purchases of reserves in place . . . . .	187	6	193
Sales of reserves in place . . . . .	(48)	(36)	(84)
Changes in timing and other . . . . .	24	(33)	(9)

	<u>United States</u>	<u>Canada</u>	<u>Total</u>
Balance, December 31, 2001 .....	\$ 441	\$ 538	\$ 979
Sales and transfers of gas, natural gas liquids and crude oil produced, net of production costs .....	(140)	(143)	(283)
Net changes in prices and production costs .....	529	640	1,169
Extensions, discoveries, additions and improved recovery, net of related costs .....	120	44	164
Development costs incurred .....	47	(22)	25
Revisions of previous quantity estimates and development costs .....	(88)	12	(76)
Accretion of discount .....	44	6	50
Net change in income taxes .....	(181)	(65)	(246)
Purchases of reserves in place .....	—	2	2
Sales of reserves in place .....	(6)	(515)	(521)
Changes in timing and other .....	<u>10</u>	<u>(14)</u>	<u>(4)</u>
Balance, December 31, 2002 .....	<u>\$ 776</u>	<u>\$ 483</u>	<u>\$ 1,259</u>

## EXHIBIT INDEX

<u>Exhibit Number</u>	<u>Description</u>
3.1.1	Amended and Restated Certificate of Incorporation of Calpine Corporation.(a)
3.1.2	Certificate of Correction of Calpine Corporation.(b)
3.1.3	Certificate of Amendment of Amended and Restated Certificate of Incorporation of Calpine Corporation.(c)
3.1.4	Certificate of Designation of Series A Participating Preferred Stock of Calpine Corporation.(b)
3.1.5	Amended Certificate of Designation of Series A Participating Preferred Stock of Calpine Corporation.(b)
3.1.6	Amended Certificate of Designation of Series A Participating Preferred Stock of Calpine Corporation.(c)
3.1.7	Certificate of Designation of Special Voting Preferred Stock of Calpine Corporation.(d)
3.1.8	Certificate of Ownership and Merger Merging Calpine Natural Gas GP, Inc. into Calpine Corporation.(e)
3.1.9	Certificate of Ownership and Merger Merging Calpine Natural Gas Company into Calpine Corporation.(e)
3.1.10	Amended and Restated By-laws of Calpine Corporation.(f)
4.1.1	Indenture dated as of May 16, 1996, between the Company and Fleet National Bank, as Trustee, including form of Notes.(g)
4.1.2	First Supplemental Indenture dated as of August 1, 2000, between the Company and State Street Bank and Trust Company (successor trustee to Fleet National Bank), as Trustee.(b)
4.2.1	Indenture dated as of July 8, 1997, between the Company and The Bank of New York, as Trustee, including form of Notes.(h)
4.2.2	Supplemental Indenture dated as of September 10, 1997, between the Company and The Bank of New York, as Trustee.(i)
4.2.3	Second Supplemental Indenture dated as of July 31, 2000, between the Company and The Bank of New York, as Trustee.(b)
4.3.1	Indenture dated as of March 31, 1998, between the Company and The Bank of New York, as Trustee, including form of Notes.(j)
4.3.2	Supplemental Indenture dated as of July 24, 1998, between the Company and The Bank of New York, as Trustee.(j)
4.3.3	Second Supplemental Indenture dated as of July 31, 2000, between the Company and The Bank of New York, as Trustee.(b)
4.4.1	Indenture dated as of March 29, 1999, between the Company and The Bank of New York, as Trustee, including form of Notes.(k)
4.4.2	First Supplemental Indenture dated as of July 31, 2000, between the Company and The Bank of New York, as Trustee.(b)
4.5.1	Indenture dated as of March 29, 1999, between the Company and The Bank of New York, as Trustee, including form of Notes.(k)
4.5.2	First Supplemental Indenture dated as of July 31, 2000, between the Company and The Bank of New York, as Trustee.(b)
4.6.1	Indenture dated as of August 10, 2000, between the Company and Wilmington Trust Company, as Trustee.(l)
4.6.2	First Supplemental Indenture dated as of September 28, 2000, between the Company and Wilmington Trust Company, as Trustee.(b)
4.7	Indenture, dated as of April 30, 2001, between the Company and Wilmington Trust Company, as Trustee.(m)
4.8	Amended and Restated Indenture dated as of October 16, 2001, between Calpine Canada Energy Finance ULC and Wilmington Trust Company, as Trustee.(n)

<u>Exhibit Number</u>	<u>Description</u>
4.9	Guarantee Agreement dated as of April 25, 2001, between the Company and Wilmington Trust Company, as Trustee.(o)
4.10	First Amendment, dated as of October 16, 2001, to Guarantee Agreement dated as of April 25, 2001, between the Company and Wilmington Trust Company, as Trustee.(n)
4.11	Indenture dated as of October 18, 2001, between Calpine Canada Energy Finance II ULC and Wilmington Trust Company, as Trustee.(n)
4.12	First Supplemental Indenture, dated as of October 18, 2001, between Calpine Canada Energy Finance II ULC and Wilmington Trust Company, as Trustee.(n)
4.13	Guarantee Agreement dated as of October 18, 2001, between the Company and Wilmington Trust Company, as Trustee.(n)
4.14	First Amendment, dated as of October 18, 2001, to Guarantee Agreement dated as of October 18, 2001, between the Company and Wilmington Trust Company, as Trustee.(n)
4.15	Amended and Restated Rights Agreement, dated as of September 19, 2001, between Calpine Corporation and Equiserve Trust Company, N.A., as Rights Agent.(p)
4.16	Form of Exchangeable Share Provisions and Other Provisions to Be Included in the Articles of Calpine Canada Holdings Ltd. (included as Exhibit B to Exhibit 10.1.2).(d)
4.17	Form of Support Agreement between the Company and Calpine Canada Holdings Ltd. (included as Exhibit C to Exhibit 10.1.1).(d)
4.18	HIGH TIDES I.
4.18.1	Certificate of Trust of Calpine Capital Trust, a Delaware statutory trust, dated September 29, 1999.(q)
4.18.2	Corrected Certificate of Certificate of Trust of Calpine Capital Trust, a Delaware statutory trust, filed October 4, 1999.(q)
4.18.3	Declaration of Trust of Calpine Capital Trust, dated as of October 4, 1999, among Calpine Corporation, as Depositor, The Bank of New York (Delaware), as Delaware Trustee, The Bank of New York, as Property Trustee, and the Administrative Trustees named therein.(q)
4.18.4	Indenture, dated as of November 2, 1999, between Calpine Corporation and The Bank of New York, as Trustee, including form of Debenture.(q)
4.18.5	Remarketing Agreement, dated November 2, 1999, among Calpine Corporation, Calpine Capital Trust, The Bank of New York, as Tender Agent, and Credit Suisse First Boston Corporation, as Remarketing Agent.(q)
4.18.6	Amended and Restated Declaration of Trust of Calpine Capital Trust, dated as of November 2, 1999, among Calpine Corporation, as Depositor and Debenture Issuer, The Bank of New York (Delaware), as Delaware Trustee, and The Bank of New York, as Property Trustee, and the Administrative Trustees named therein, including form of Preferred Security and form of Common Security.(q)
4.18.7	Preferred Securities Guarantee Agreement, dated as of November 2, 1999, between Calpine Corporation and The Bank of New York, as Guarantee Trustee.(q)
4.19	HIGH TIDES II.
4.19.1	Certificate of Trust of Calpine Capital Trust II, a Delaware statutory trust, filed January 25, 2000.(r)
4.19.2	Declaration of Trust of Calpine Capital Trust II, dated as of January 24, 2000, among Calpine Corporation, as Depositor and Debenture Issuer, The Bank of New York (Delaware), as Delaware Trustee, The Bank of New York, as Property Trustee, and the Administrative Trustees named therein.(r)
4.19.3	Indenture, dated as of January 31, 2000, between Calpine Corporation and The Bank of New York, as Trustee, including form of Debenture.(r)
4.19.4	Remarketing Agreement, dated as of January 31, 2000, among Calpine Corporation, Calpine Capital Trust II, The Bank of New York, as Tender Agent, and Credit Suisse First Boston Corporation, as Remarketing Agent.(r)

<u>Exhibit Number</u>	<u>Description</u>
4.19.5	Registration Rights Agreement, dated January 31, 2000, among Calpine Corporation, Calpine Capital Trust II, Credit Suisse First Boston Corporation and ING Barings LLC.(r)
4.19.6	Amended and Restated Declaration of Trust of Calpine Capital Trust II, dated as of January 31, 2000, among Calpine Corporation, as Depositor and Debenture Issuer, The Bank of New York (Delaware), as Delaware Trustee, The Bank of New York, as Property Trustee, and the Administrative Trustees named therein, including form of Preferred Security and form of Common Security.(r)
4.19.7	Preferred Securities Guarantee Agreement, dated as of January 31, 2000, between Calpine Corporation and The Bank of New York, as Guarantee Trustee.(r)
4.20	HIGH TIDES III.
4.20.1	Amended and Restated Certificate of Trust of Calpine Capital Trust III, a Delaware statutory trust, filed July 19, 2000.(s)
4.20.2	Declaration of Trust of Calpine Capital Trust III dated June 28, 2000, among the Company, as Depositor and Debenture Issuer, The Bank of New York (Delaware), as Delaware Trustee, The Bank of New York, as Property Trustee and the Administrative Trustees named therein.(s)
4.20.3	Amendment No. 1 to the Declaration of Trust of Calpine Capital Trust III dated July 19, 2000, among the Company, as Depositor and Debenture Issuer, Wilmington Trust Company, as Delaware Trustee, Wilmington Trust Company, as Property Trustee, and the Administrative Trustees named therein.(s)
4.20.4	Indenture dated as of August 9, 2000, between the Company and Wilmington Trust Company, as Trustee.(s)
4.20.5	Remarketing Agreement dated as of August 9, 2000, among the Company, Calpine Capital Trust III, Wilmington Trust Company, as Tender Agent, and Credit Suisse First Boston Corporation, as Remarketing Agent.(s)
4.20.6	Registration Rights Agreement dated as August 9, 2000, between the Company, Calpine Capital Trust III, Credit Suisse First Boston Corporation, ING Barings LLC and CIBC World Markets Corp.(s)
4.20.7	Amended and Restated Declaration of Trust of Calpine Capital Trust III dated as of August 9, 2000, the Company, as Depositor and Debenture Issuer, Wilmington Trust Company, as Delaware Trustee, Wilmington Trust Company, as Property Trustee, and the Administrative Trustees named therein, including the form of Preferred Security and form of Common Security.(s)
4.20.8	Preferred Securities Guarantee Agreement dated as of August 9, 2000, between the Company, as Guarantor, and Wilmington Trust Company, as Guarantee Trustee.(s)
4.21	PASS THROUGH CERTIFICATES (TIVERTON AND RUMFORD).
4.21.1	Pass Through Trust Agreement dated as of December 19, 2000, among Tiverton Power Associates Limited Partnership, Rumford Power Associates Limited Partnership and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including the form of Certificate.(b)
4.21.2	Participation Agreement dated as of December 19, 2000, among the Company, Tiverton Power Associates Limited Partnership, Rumford Power Associates Limited Partnership, PMCC Calpine New England Investment LLC, PMCC Calpine NEIM LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee.(b)
4.21.3	Appendix A — Definitions and Rules of Interpretation.(b)
4.21.4	Indenture of Trust, Mortgage and Security Agreement, dated as of December 19, 2000, between PMCC Calpine New England Investment LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, including the forms of Lessor Notes.(b)
4.21.5	Calpine Guaranty and Payment Agreement (Tiverton) dated as of December 19, 2000, by Calpine, as Guarantor, to PMCC Calpine New England Investment LLC, PMCC Calpine NEIM LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(b)

<u>Exhibit Number</u>	<u>Description</u>
4.21.6	Calpine Guaranty and Payment Agreement (Rumford) dated as of December 19, 2000, by Calpine, as Guarantor, to PMCC Calpine New England Investment LLC, PMCC Calpine NEIM LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(b)
4.22	PASS THROUGH CERTIFICATES (SOUTH POINT, BROAD RIVER AND ROCKGEN).
4.22.1	Pass Through Trust Agreement A dated as of October 18, 2001, among South Point Energy Center, LLC, Broad River Energy LLC, RockGen Energy LLC and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including the form of 8.400% Pass Through Certificate, Series A.(f)
4.22.2	Pass Through Trust Agreement B dated as of October 18, 2001, among South Point Energy Center, LLC, Broad River Energy LLC, RockGen Energy LLC and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including the form of 9.825% Pass Through Certificate, Series B.(f)
4.22.3	Participation Agreement (SP-1) dated as of October 18, 2001, among the Company, South Point Energy Center, LLC, South Point OL-1, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-1, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(f)
4.22.4	Participation Agreement (SP-2) dated as of October 18, 2001, among the Company, South Point Energy Center, LLC, South Point OL-2, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-2, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(f)
4.22.5	Participation Agreement (SP-3) dated as of October 18, 2001, among the Company, South Point Energy Center, LLC, South Point OL-3, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-3, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(f)
4.22.6	Participation Agreement (SP-4) dated as of October 18, 2001, among the Company, South Point Energy Center, LLC, South Point OL-4, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-4, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(f)
4.22.7	Participation Agreement (BR-1) dated as of October 18, 2001, among the Company, Broad River Energy LLC, Broad River OL-1, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-1, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(f)
4.22.8	Participation Agreement (BR-2) dated as of October 18, 2001, among the Company, Broad River Energy LLC, Broad River OL-2, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-2, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(f)
4.22.9	Participation Agreement (BR-3) dated as of October 18, 2001, among the Company, Broad River Energy LLC, Broad River OL-3, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-3, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(f)

<u>Exhibit Number</u>	<u>Description</u>
4.22.10	Participation Agreement (BR-4) dated as of October 18, 2001, among the Company, Broad River Energy LLC, Broad River OL-4, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-4, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(f)
4.22.11	Participation Agreement (RG-1) dated as of October 18, 2001, among the Company, RockGen Energy LLC, RockGen OL-1, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-1, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(f)
4.22.12	Participation Agreement (RG-2) dated as of October 18, 2001, among the Company, RockGen Energy LLC, RockGen OL-2, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-2, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(f)
4.22.13	Participation Agreement (RG-3) dated as of October 18, 2001, among the Company, RockGen Energy LLC, RockGen OL-3, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-3, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(f)
4.22.14	Participation Agreement (RG-4) dated as of October 18, 2001, among the Company, RockGen Energy LLC, RockGen OL-4, LLC, Wells Fargo Bank Northwest, National Association, as Lessor Manager, SBR OP-4, LLC, State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, National Association, as Pass Through Trustee, including Appendix A — Definitions and Rules of Interpretation.(f)
4.22.15	Indenture of Trust, Deed of Trust, Assignment of Rents and Leases, Security Agreement and Financing Statement, dated as of October 18, 2001, between South Point OL-1, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee and Account Bank, including the form of South Point Lessor Notes.(f)
4.22.16	Indenture of Trust, Deed of Trust, Assignment of Rents and Leases, Security Agreement and Financing Statement, dated as of October 18, 2001, between South Point OL-2, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee and Account Bank, including the form of South Point Lessor Notes.(f)
4.22.17	Indenture of Trust, Deed of Trust, Assignment of Rents and Leases, Security Agreement and Financing Statement, dated as of October 18, 2001, between South Point OL-3, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee and Account Bank, including the form of South Point Lessor Notes.(f)
4.22.18	Indenture of Trust, Deed of Trust, Assignment of Rents and Leases, Security Agreement and Financing Statement, dated as of October 18, 2001, between South Point OL-4, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee and Account Bank, including the form of South Point Lessor Notes.(f)
4.22.19	Indenture of Trust, Mortgage, Security Agreement and Fixture Filing, dated as of October 18, 2001, between Broad River OL-1, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, Mortgagee and Account Bank, including the form of Broad River Lessor Notes.(f)
4.22.20	Indenture of Trust, Mortgage, Security Agreement and Fixture Filing, dated as of October 18, 2001, between Broad River OL-2, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, Mortgagee and Account Bank, including the form of Broad River Lessor Notes.(f)

<u>Exhibit Number</u>	<u>Description</u>
4.22.21	Indenture of Trust, Mortgage, Security Agreement and Fixture Filing, dated as of October 18, 2001, between Broad River OL-3, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, Mortgagee and Account Bank, including the form of Broad River Lessor Notes.(f)
4.22.22	Indenture of Trust, Mortgage, Security Agreement and Fixture Filing, dated as of October 18, 2001, between Broad River OL-4, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee, Mortgagee and Account Bank, including the form of Broad River Lessor Notes.(f)
4.22.23	Indenture of Trust, Mortgage and Security Agreement, dated as of October 18, 2001, between RockGen OL-1, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee and Account Bank, including the form of RockGen Lessor Notes.(f)
4.22.24	Indenture of Trust, Mortgage and Security Agreement, dated as of October 18, 2001, between RockGen OL-2, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee and Account Bank, including the form of RockGen Lessor Notes.(f)
4.22.25	Indenture of Trust, Mortgage and Security Agreement, dated as of October 18, 2001, between RockGen OL-3, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee and Account Bank, including the form of RockGen Lessor Notes.(f)
4.22.26	Indenture of Trust, Mortgage and Security Agreement, dated as of October 18, 2001, between RockGen OL-4, LLC and State Street Bank and Trust Company of Connecticut, National Association, as Indenture Trustee and Account Bank, including the form of RockGen Lessor Notes.(f)
4.22.27	Calpine Guaranty and Payment Agreement (South Point SP-1) dated as of October 18, 2001, by Calpine, as Guarantor, to South Point OL-1, LLC, SBR OP-1, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(f)
4.22.28	Calpine Guaranty and Payment Agreement (South Point SP-2) dated as of October 18, 2001, by Calpine, as Guarantor, to South Point OL-2, LLC, SBR OP-2, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(f)
4.22.29	Calpine Guaranty and Payment Agreement (South Point SP-3) dated as of October 18, 2001, by Calpine, as Guarantor, to South Point OL-3, LLC, SBR OP-3, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(f)
4.22.30	Calpine Guaranty and Payment Agreement (South Point SP-4) dated as of October 18, 2001, by Calpine, as Guarantor, to South Point OL-4, LLC, SBR OP-4, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(f)
4.22.31	Calpine Guaranty and Payment Agreement (Broad River BR-1) dated as of October 18, 2001, by Calpine, as Guarantor, to Broad River OL-1, LLC, SBR OP-1, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(f)
4.22.32	Calpine Guaranty and Payment Agreement (Broad River BR-2) dated as of October 18, 2001, by Calpine, as Guarantor, to Broad River OL-2, LLC, SBR OP-2, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(f)
4.22.33	Calpine Guaranty and Payment Agreement (Broad River BR-3) dated as of October 18, 2001, by Calpine, as Guarantor, to Broad River OL-3, LLC, SBR OP-3, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(f)

<u>Exhibit Number</u>	<u>Description</u>
4.22.34	Calpine Guaranty and Payment Agreement (Broad River BR-4) dated as of October 18, 2001, by Calpine, as Guarantor, to Broad River OL-4, LLC, SBR OP-4, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(f)
4.22.35	Calpine Guaranty and Payment Agreement (RockGen RG-1) dated as of October 18, 2001, by Calpine, as Guarantor, to RockGen OL-1, LLC, SBR OP-1, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(f)
4.22.36	Calpine Guaranty and Payment Agreement (RockGen RG-2) dated as of October 18, 2001, by Calpine, as Guarantor, to RockGen OL-2, LLC, SBR OP-2, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(f)
4.22.37	Calpine Guaranty and Payment Agreement (RockGen RG-3) dated as of October 18, 2001, by Calpine, as Guarantor, to RockGen OL-3, LLC, SBR OP-3, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(f)
4.22.38	Calpine Guaranty and Payment Agreement (RockGen RG-4) dated as of October 18, 2001, by Calpine, as Guarantor, to RockGen OL-4, LLC, SBR OP-4, LLC, State Street Bank and Trust Company of Connecticut, as Indenture Trustee, and State Street Bank and Trust Company of Connecticut, as Pass Through Trustee.(f)
9.1	Form of Voting and Exchange Trust Agreement between the Company, Calpine Canada Holdings Ltd. and CIBC Mellon Trust Company, as Trustee (included as Exhibit D to Exhibit 10.1.1).(d)
10.1	Purchase Agreements.
10.1.1	Combination Agreement, dated as of February 7, 2001, by and between the Company and Encal Energy Ltd.(d)
10.1.2	Amending Agreement to the Combination Agreement, dated as of March 16, 2001, between the Company and Encal Energy Ltd.(t)
10.1.3	Form of Plan of Arrangement Under Section 186 of the Business Corporations Act (Alberta) Involving and Affecting Encal Energy Ltd. and the Holders of its Common Shares and Options (included as Exhibit A to Exhibit 10.1.1).(d)
10.2	Financing Agreements.
10.2.1	Amended and Restated Calpine Construction Finance Company Financing Agreement (“CCFC I”), dated as of February 15, 2001.(d) (u)
10.2.2	Calpine Construction Finance Company Financing Agreement (“CCFC II”), dated as of October 16, 2000.(b) (v)
10.2.3	Second Amended and Restated Credit Agreement, dated as of May 23, 2000 (“Second Amended and Restated Credit Agreement”), among the Company, Bayerische Landesbank, as Co-Arranger and Syndication Agent, The Bank of Nova Scotia, as Lead Arranger and Administrative Agent, and the Lenders named therein.(w)
10.2.4	First Amendment and Waiver to Second Amended and Restated Credit Agreement, dated as of April 19, 2001, among the Company, The Bank of Nova Scotia, as Administrative Agent, and the Lenders named therein.(f)
10.2.5	Second Amendment to Second Amended and Restated Credit Agreement, dated as of March 8, 2002, among the Company, The Bank of Nova Scotia, as Administrative Agent, and the Lenders named therein.(f)
10.2.6	Third Amendment to Second Amended and Restated Credit Agreement, dated as of May 9, 2002, among the Company, The Bank of Nova Scotia, as Administrative Agent, and the Lenders named therein.(e)
10.2.7	Fourth Amendment to Second Amended and Restated Credit Agreement, dated as of September 26, 2002, among the Company, The Bank of Nova Scotia, as Administrative Agent, and the Lenders named therein.(x)

<u>Exhibit Number</u>	<u>Description</u>
10.2.8	Fifth Amendment to Second Amended and Restated Credit Agreement, dated as of March 12, 2003, among the Company, The Bank of Nova Scotia, as Administrative Agent, and the Lenders named therein.(*)
10.2.9	Credit Agreement, dated as of March 8, 2002, among the Company, the Lenders named therein, The Bank of Nova Scotia and Bayerische Landesbank Girozentrale, as lead arrangers and bookrunners, Salomon Smith Barney Inc. and Deutsche Banc Alex. Brown Inc., as lead arrangers and bookrunners, Bank of America, National Association, and Credit Suisse First Boston, Cayman Islands Branch, as lead arrangers and syndication agents, TD Securities (USA) Inc., as lead arranger, The Bank of Nova Scotia, as joint administrative agent and funding agent, and Citicorp USA, Inc., as joint administrative agent.(f)
10.2.10	First Amendment to Credit Agreement, dated as of May 9, 2002, among the Company, The Bank of Nova Scotia, as Joint Administrative Agent and Funding Agent, Citicorp USA, Inc., as Joint Administrative Agent, and the Lenders named therein.(e)
10.2.11	Increase in Term B Loan Commitment Amount Notice, effective as of May 31, 2002, by The Bank of Nova Scotia and Citicorp USA, Inc., as Administrative Agents.(y)
10.2.12	Assignment and Security Agreement, dated as of March 8, 2002, by the Company in favor of The Bank of Nova Scotia, as administrative agent for each of the Lender Parties named therein.(f)
10.2.13	Pledge Agreement, dated as of March 8, 2002, by the Company in favor of The Bank of Nova Scotia, as Agent for the Lender Parties named therein.(f)
10.2.14	Amendment Number One to Pledge Agreement, dated as of May 9, 2002, among the Company and The Bank of Nova Scotia, as Joint Administrative Agent and Funding Agent.(e)
10.2.15	Pledge Agreement, dated as of March 8, 2002, by Quintana Minerals (USA), Inc., JOQ Canada, Inc. and Quintana Canada Holdings, LLC in favor of The Bank of Nova Scotia, as Agent for the Lender Parties named therein.(f)
10.2.16	Guarantee, dated as of March 8, 2002, by Quintana Minerals (USA), Inc., JOQ Canada, Inc. and Quintana Canada Holdings, LLC, in favor of each of the Lender Parties named therein.(f)
10.2.17	First Amendment Pledge Agreement, dated as of May 9, 2002, by the Company in favor of The Bank of Nova Scotia, as Agent for each of the Lender Parties named therein.(e)
10.2.18	First Amendment Pledge Agreement (Membership Interests), dated as of May 9, 2002, by the Company in favor of The Bank of Nova Scotia, as Agent for each of the Lender Parties named therein.(e)
10.2.19	Note Pledge Agreement, dated as of May 9, 2002, by the Company in favor of The Bank of Nova Scotia, as Agent for each of the Lender Parties named therein.(e)
10.2.20	Hazardous Materials Undertaking and Indemnity (Multistate), dated as of May 9, 2002, by the Company in favor of The Bank of Nova Scotia, as Agent.(y)
10.2.21	Hazardous Materials Undertaking and Indemnity (California), dated as of May 9, 2002, by the Company in favor of The Bank of Nova Scotia, as Agent.(y)
10.2.22	Form of Mortgage, Deed of Trust, Assignment, Security Agreement, Financing Statement and Fixture Filing (Multistate), from the Company to Jon Burckin and Kemp Leonard, as Trustees, and The Bank of Nova Scotia, as Agent.(y)
10.2.23	Form of Deed of Trust with Power of Sale, Assignment of Production, Security Agreement, Financing Statement and Fixture Filing (California), dated as of May 1, 2002, from the Company to Chicago Title Insurance Co.(y)
10.2.24	Form of Mortgage, Deed of Trust, Assignment, Security Agreement, Financing Statement and Fixture Filing (Colorado), dated as of May 1, 2002, from the Company to Kemp Leonard and John Quick, as Trustees, and The Bank of Nova Scotia, as Agent.(y)
10.2.25	Form of Mortgage, Assignment, Security Agreement and Financing Statement (Louisiana), dated as of May 1, 2002, from the Company to The Bank of Nova Scotia, as Agent.(y)
10.2.26	Form of Mortgage, Deed of Trust, Assignment, Security Agreement, Financing Statement and Fixture Filing (New Mexico), dated as of May 1, 2002, from the Company to Kemp Leonard and John Quick, as Trustees, and The Bank of Nova Scotia, as Agent.(y)
10.3	Other Agreements.

<u>Exhibit Number</u>	<u>Description</u>
10.3.1	Calpine Corporation Stock Option Program and forms of agreements there under.(z) (bb)
10.3.2	Calpine Corporation 1996 Stock Incentive Plan and forms of agreements there under.(aa) (bb)
10.3.3	Employment Agreement, dated as of January 1, 2000, between Calpine Corporation and Mr. Peter Cartwright.(r) (bb)
10.3.4	Employment Agreement, dated as of January 1, 2000, between Calpine Corporation and Ms. Ann B. Curtis.(f) (bb)
10.3.5	Employment Agreement, dated as of January 1, 2000, between Calpine Corporation and Mr. Ron A. Walter.(f) (bb)
10.3.6	Employment Agreement, dated as of January 1, 2000, between Calpine Corporation and Mr. Robert D. Kelly.(f) (bb)
10.3.7	Employment Agreement, dated as of January 1, 2000, between Calpine Corporation and Mr. Thomas R. Mason.(f) (bb)
10.3.8	Calpine Corporation Annual Management Incentive Plan.(cc) (bb)
10.3.9	\$500,000 Promissory Note Secured by Deed of Trust made by Thomas R. Mason and Debra J. Mason in favor of Calpine Corporation.(cc) (bb)
10.3.10	2000 Employee Stock Purchase Plan (dd) (bb)
10.4.1	Form of Indemnification Agreement for directors and officers.(aa) (bb)
10.4.2	Form of Indemnification Agreement for directors and officers.(f) (bb)
12.1	Statement on Computation of Ratio of Earnings to Fixed Charges.(*)
21.1	Subsidiaries of the Company.(*)
23.1	Consent of Deloitte & Touche 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 Gilbert Laustsen Jung Associates, Ltd., independent engineer.(*)
24.1	Power of Attorney of Officers and Directors of Calpine Corporation (set forth on the signature pages of this report).(*)
99.1	Certification of Chief Executive Officer and Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.(*)

(\* ) Filed herewith.

- (a) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-3 (Registration No. 333-40652) filed with the SEC on June 30, 2000.
- (b) Incorporated by reference to Calpine Corporation's Annual Report on Form 10-K for the year ended December 31, 2000, filed with the SEC on March 15, 2001.
- (c) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-3 (Registration No. 333-66078) filed with the SEC on July 27, 2001.
- (d) Incorporated by reference to Calpine Corporation's Quarterly Report on Form 10-Q dated March 31, 2001, filed with the SEC on May 15, 2001.
- (e) Incorporated by reference to Calpine Corporation's Quarterly Report on Form 10-Q dated March 31, 2002, filed with the SEC on May 15, 2002.
- (f) Incorporated by reference to Calpine Corporation's Annual Report on Form 10-K dated December 31, 2001, filed with the SEC on March 29, 2002.
- (g) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-4 (Registration Statement No. 333-06259) filed with the SEC on June 19, 1996.
- (h) Incorporated by reference to Calpine Corporation's Quarterly Report on Form 10-Q dated June 30, 1997, filed with the SEC on August 14, 1997.

- (i) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-4 (Registration Statement No. 333-41261) filed with the SEC on November 28, 1997.
- (j) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-4 (Registration Statement No. 333-61047) filed with the SEC on August 10, 1998.
- (k) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-3/A (Registration Statement No. 333-72583) filed with the SEC on March 8, 1999.
- (l) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-3 (Registration No. 333-76880) filed with the SEC on January 17, 2002.
- (m) Incorporated by reference to Calpine Corporation's Current Report on Form 8-K dated October 16, 2001, filed with the SEC on November 13, 2001.
- (n) Incorporated by reference to Calpine Corporation's Current Report on Form 8-K dated October 16, 2001, filed with the SEC on November 13, 2001.
- (o) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-3/A (Registration No. 333-57338) filed with the SEC on April 19, 2001.
- (p) Incorporated by reference to Calpine Corporation's Registration Statement on Form 8-A/A (Registration No. 001-12079) filed with the SEC on September 28, 2001.
- (q) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-3/A (Registration Statement No. 333-87427) filed with the SEC on October 26, 1999.
- (r) Incorporated by reference to Calpine Corporation's Annual Report on Form 10-K for the year ended December 31, 1999, filed with the SEC on February 29, 2000.
- (s) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-3 (Registration Statement No. 333-47068) filed with the SEC on September 29, 2000.
- (t) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-3/A (Registration Statement No. 333-56712) filed with the SEC on April 17, 2001.
- (u) Approximately 24 pages of this exhibit have been omitted pursuant to a request for confidential treatment. The omitted language has been filed separately with the SEC.
- (v) Approximately 71 pages of this exhibit have been omitted pursuant to a request for confidential treatment. The omitted language has been filed separately with the SEC.
- (w) Incorporated by reference to Calpine Corporation's Current Report on Form 8-K dated July 25, 2000, filed with the SEC on August 9, 2000.
- (x) Incorporated by reference to Calpine Corporation's Quarterly Report on Form 10-Q dated September 30, 2002, filed with the SEC on November 14, 2002.
- (y) Incorporated by reference to Calpine Corporation's Quarterly Report on Form 10-Q dated June 30, 2002, filed with the SEC on August 12, 2002.
- (z) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-1 (Registration Statement No. 33-73160) filed with the SEC on December 20, 1993.
- (aa) Incorporated by reference to Calpine Corporation's Registration Statement on Form S-1/A (Registration Statement No. 333-07497) filed with the SEC on August 22, 1996.
- (bb) Management contract or compensatory plan or arrangement.
- (cc) Incorporated by reference to Calpine Corporation's Current Report on Form 8-K dated March 30, 2000, filed with the SEC on April 3, 2000.
- (dd) Incorporated by reference to Calpine Corporation's Definitive Proxy Statement on Schedule 14A dated April 13, 2000, filed with the SEC on April 13, 2000.