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CALPINE CORP

FORM 10-Q
(Quarterly Report)

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Telephone	7138302000
CIK	0000916457
Symbol	CPN
SIC Code	4911 - Electric Services
Industry	Electric Utilities
Sector	Utilities
Fiscal Year	12/31

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CALPINE CORP

FORM 10-Q
(Quarterly Report)

Filed 11/14/2002 For Period Ending 9/30/2002

Address	50 WEST SAN FERNANDO ST
	SAN JOSE, California 95113
Telephone	408-995-5115
CIK	0000916457
Industry	Electric Utilities
Sector	Utilities
Fiscal Year	12/31

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

[X] QUARTERLY REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934

For the quarterly period ended September 30, 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

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

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 [X] No [ ]

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date:

377,999,176 shares of Common Stock, par value $.001 per share, outstanding on November 12, 2002

CALPINE CORPORATION AND SUBSIDIARIES
Report on Form 10-Q
For the Quarter Ended September 30, 2002

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PART I - FINANCIAL INFORMATION

Item 1. Financial Statements.

CALPINE CORPORATION AND SUBSIDIARIES
Consolidated Condensed Balance Sheets
September 30, 2002 and December 31, 2001
(In thousands, except share amounts)

	September 30, 2002 (unaudited)	December 31, 2001
ASSETS		
Current assets:		
Cash and cash equivalents	$ 659,694	$ 1,525,417
Accounts receivable, net	838,632	956,596
Margin deposits and other prepaid expense	200,036	480,656
Inventories	104,813	78,862
Current derivative assets	556,259	763,162
Current assets held for sale	19,920	9,484
Other current assets	297,742	193,525
Total current assets	2,677,096	4,007,702
Restricted cash	101,291	95,833
Notes receivable, net of current portion	193,767	158,124
Project development costs	156,743	176,296
Investments in power projects	428,610	390,609
Deferred financing costs	213,636	210,811
Property, plant and equipment, net	17,483,400	14,971,080
Goodwill and other intangible assets, net	128,281	141,120
Long-term derivative assets	548,510	564,952
Long-term assets held for sale	241,474	308,463
Other assets	516,518	304,562
Total assets	$ 22,689,326	$ 21,329,552
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 1,117,801	$ 1,283,843
Accrued payroll and related expense	46,352	57,285
Accrued interest payable	202,947	160,115
Notes payable and borrowings under lines of credit, current portion	250,389	23,238
Capital lease obligation, current portion	3,001	2,206
Construction/project financing, current portion	167,509	--
Zero-Coupon Convertible Debentures Due 2021	--	878,000
Current derivative liabilities	449,521	625,339
Current liabilities held for sale	4,522	4,576
Other current liabilities	193,117	194,236
Total current liabilities	2,435,159	3,228,838
Term loan	1,000,000	--
Notes payable and borrowings under lines of credit, net of current portion	2,453	74,750
Capital lease obligation, net of current portion	205,149	207,219
Construction/project financing, net of current portion	3,510,595	3,393,410
Convertible Senior Notes Due 2006	1,200,000	1,100,000
Senior notes	7,089,746	7,049,038
Deferred income taxes, net	1,036,539	958,399
Deferred lease incentive	54,608	57,236
Deferred revenue	243,214	154,381
Long-term derivative liabilities	549,569	822,848
Long-term liabilities held for sale	5,983	5,947
Other liabilities	112,409	96,504
Total liabilities	17,445,424	17,148,570
Company-obligated mandatorily redeemable convertible preferred securities of subsidiary trusts	1,123,787	1,123,024
Minority interests	198,875	47,389

(continues next page)

CALPINE CORPORATION AND SUBSIDIARIES

Consolidated Condensed Balance Sheets

September 30, 2002 and December 31, 2001

(In thousands, except share amounts)

(continued)

	September 30, 2002 (unaudited)	December 31, 2001
LIABILITIES AND STOCKHOLDERS' EQUITY (continued)		
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 in 2002 and 2001; issued and outstanding 377,830,124 shares in 2002 and 307,058,751 shares in 2001	378	307
Additional paid-in capital	2,795,582	2,040,836
Retained earnings	1,355,597	1,196,000
Accumulated other comprehensive (loss)	(230,317)	(226,574)
Total stockholders' equity	3,921,240	3,010,569
Total liabilities and stockholders' equity	$ 22,689,326	$ 21,329,552

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

CALPINE CORPORATION AND SUBSIDIARIES

Consolidated Condensed Statements of Operations For the Three and Nine Months Ended September 30, 2002 and 2001

(In thousands, except per share amounts)

(unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
Revenue:				
Electric generation and marketing revenue				
Electricity and steam revenue	$ 947,326	$ 710,506	$ 2,269,892	$ 1,804,889
Sales of purchased power for hedging and optimization	1,282,976	1,653,088	2,526,555	2,680,488
Total electric generation and marketing revenue	2,230,302	2,363,594	4,796,447	4,485,377
Oil and gas production and marketing revenue				
Oil and gas sales	21,827	54,693	89,585	239,940
Sales of purchased gas for hedging and optimization	231,893	56,916	666,095	412,782
Total oil and gas production and marketing revenue	253,720	111,609	755,680	652,722
Trading revenue, net				
Realized revenue on power and gas trading transactions, net	6,845	16,700	15,276	21,340
Unrealized mark-to-market gain (loss) on power and gas transactions, net	(10,957)	7,128	(5,952)	107,862
Total trading revenue, net	(4,112)	23,828	9,324	129,202
Income from unconsolidated investments in power projects	10,176	6,859	10,499	9,021
Other revenue	4,924	14,261	14,792	28,444
Total revenue	2,495,010	2,520,151	5,586,742	5,304,766
Cost of revenue:				
Electric generation and marketing expense				
Plant operating expense	141,262	93,709	374,497	246,045
Royalty expense	4,743	5,255	13,092	23,181
Purchased power expense for hedging and optimization	1,059,840	1,394,871	2,039,954	2,396,804
Total electric generation and marketing expense	1,205,845	1,493,835	2,427,543	2,666,030
Oil and gas production and marketing expense				
Oil and gas production expense	22,953	13,009	67,381	62,371
Purchased gas expense for hedging and optimization	220,775	52,856	678,192	389,814
Total oil and gas production and marketing expense	243,728	65,865	745,573	452,185
Fuel expense	525,478	327,947	1,208,092	846,195
Depreciation, depletion and amortization expense	117,568	80,044	310,943	199,509
Operating lease expense	36,520	27,830	108,917	83,289
Other expense	3,539	3,485	8,333	9,474
Total cost of revenue	2,132,678	1,999,006	4,809,401	4,256,682
Gross profit	362,332	521,145	777,341	1,048,084
Project development expense	23,922	4,894	59,973	25,106
Equipment cancellation charge	3,714	--	172,185	--
General and administrative expense	57,280	29,357	170,369	114,924
Merger expense	--	--	--	41,627
Income from operations	277,416	486,894	374,814	866,427
Interest expense	113,847	47,657	239,112	107,473
Distributions on trust preferred securities	15,386	15,385	46,159	45,948
Interest income	(10,842)	(21,073)	(32,780)	(60,870)
Other (income)/expense	(33,778)	(7,875)	(49,128)	(15,092)
Income before provision for income taxes	192,803	452,800	171,451	788,968
Provision for income taxes	48,406	139,304	38,805	278,161
Income before discontinued operations and cumulative effect of a change in accounting principle	144,397	313,496	132,646	510,807
Discontinued operations, net of tax provision of $9,675, $4,903, $15,059 and $24,374	16,950	7,303	26,950	36,284
Cumulative effect of a change in accounting principle, net of tax provision of $--, $--, $--and $669	--	--	--	1,036
Net income	$ 161,347	$ 320,799	$ 159,596	$ 548,127

(continues next page)

CALPINE CORPORATION AND SUBSIDIARIES

Consolidated Condensed Statements of Operations For the Three and Nine Months Ended September 30, 2002 and 2001

(In thousands, except per share amounts)

(unaudited)

(continued)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
Basic earnings per common share:				
Weighted average shares of common stock outstanding	376,957	304,666	346,816	302,649
Income before discontinued operations and cumulative effect of a change in accounting principle	$ 0.38	$ 1.03	$ 0.38	$ 1.69
Income from discontinued operations, net of tax	$ 0.05	$ 0.02	$ 0.08	$ 0.12
Cumulative effect of a change in accounting principle	$ --	$ --	$ --	$ --
Net income	$ 0.43	$ 1.05	$ 0.46	$ 1.81
Diluted earnings per common share:				
Weighted average shares of common stock outstanding before dilutive effect of certain convertible securities	382,607	318,552	355,577	317,880
Income before dilutive effect of certain convertible securities, discontinued operations and cumulative effect of a change in accounting principle	$ 0.38	$ 0.98	$ 0.37	$ 1.61
Dilutive effect of certain convertible securities (1)	$ (0.05)	$ (0.12)	$ --	$ (0.14)
Income before discontinued operations and cumulative effect of a change in accounting principle	$ 0.33	$ 0.86	$ 0.37	$ 1.47
Income from discontinued operations, net of tax	$ 0.03	$ 0.02	$ 0.08	$ 0.10
Cumulative effect of a change in accounting principle	$ --	$ --	$ --	$ --
Net income	$ 0.36	$ 0.88	$ 0.45	$ 1.57

---

(1) Includes the effect of the assumed conversion of certain dilutive convertible securities. No convertible securities were included in the nine months ended September 30, 2002, amounts as the securities were antidilutive. For the three months ended September 30, 2002, and for the three and nine months ended September 30, 2001, the assumed conversion calculation added 99,377, 58,153, and 52,353 shares of common stock and $14,326, $12,435, and $33,204 to the net income results, respectively.

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

CALPINE CORPORATION AND SUBSIDIARIES

Consolidated Condensed Statements of Cash Flows For the Nine Months Ended September 30, 2002 and 2001

(In thousands)

(unaudited)

	Nine Months Ended September 30, 2002	Nine Months Ended September 30, 2001
Cash flows from operating activities:		
Net income	$ 159,596	$ 548,127
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	368,674	242,547
Equipment cancellation cost	172,212	--
Development cost write-off	32,269	--
Deferred income taxes, net	215,296	202,444
Gain on sale of assets	(37,151)	(13,514)
(Gain) loss on extinguishment of debt	(3,491)	1,803
Minority interests	(2,672)	(3,198)
Income from unconsolidated investments in power projects	(10,499)	(9,022)
Distributions from unconsolidated investments in power projects	2,144	3,596
Change in operating assets and liabilities, net of effects of acquisitions:		
Accounts receivable	107,528	(561,964)
Notes receivable	(35,526)	(74,709)
Current derivative assets	206,903	(663,840)
Other current assets	157,690	(227,058)
Long-term derivative assets	16,442	(541,898)
Other assets	(32,853)	(115,203)
Accounts payable and accrued expense	(131,292)	421,451
Current derivative liabilities	(175,818)	(744,322)
Long-term derivative liabilities	(273,279)	459,657
Other liabilities	85,986	1,355,208
Other comprehensive income (loss) relating to derivatives	(37,144)	195,900
Net cash provided by operating activities	785,015	476,005
Cash flows from investing activities:		
Purchases of property, plant and equipment	(3,177,525)	(5,785,194)
Disposals of property, plant and equipment	125,135	21,898
Advances to joint ventures	(64,707)	(103,496)
Increase in notes receivable	8,648	(140,152)
Maturities of collateral securities	4,633	4,035
Project development costs	(84,833)	(55,734)
Increase in restricted cash	(14,453)	(35,740)
Other	5,312	8,384
Net cash used in investing activities	(3,197,790)	(6,085,999)
Cash flows from financing activities:		
Proceeds from issuance of Zero-Coupon Convertible Debentures Due 2021	--	1,000,000
Repurchase of Zero-Coupon Convertible Debentures Due 2021	(869,736)	--
Borrowings from notes payable and borrowings under lines of credit	1,252,453	141,543
Repayments of notes payable and borrowings under lines of credit	(75,734)	(444,820)
Borrowings from project financing	438,521	2,324,209
Repayments of project financing	(153,827)	(1,234,776)
Proceeds from issuance of Convertible Senior Notes Due 2006	100,000	--
Repayments of senior notes	--	(105,000)
Proceeds from senior debt offerings	--	3,853,290
Proceeds from issuance of common stock	755,363	62,283
Proceeds from Income Trust Offering	169,400	--
Financing costs	(71,665)	(86,452)
Other	--	(19,986)
Net cash provided by financing activities	1,544,775	5,490,291
Effect of exchange rate changes on cash and cash equivalents	2,277	--
Net decrease in cash and cash equivalents	(865,723)	(119,703)
Cash and cash equivalents, beginning of period	1,525,417	596,077
Cash and cash equivalents, end of period	$ 659,694	$ 476,374
Cash paid during the period for:		
Interest, net of amounts capitalized	$ 131,760	$ 27,626
Income taxes	$ 14,457	$ 114,667

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

(unaudited)

1. Organization and Operation 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, acquisition, ownership and operation of power generation facilities and the sale of electricity and its by-product, thermal energy, primarily in the form of steam. The Company has ownership interests in and operates gas-fired power generation and cogeneration facilities, gas fields, gathering systems and gas pipelines, geothermal steam fields and geothermal power generation facilities in the United States. 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. Summary of Significant Accounting Policies

Basis of Interim Presentation -- The accompanying unaudited interim consolidated condensed financial statements of the Company have been prepared by the Company pursuant to the rules and regulations of the Securities and Exchange Commission. In the opinion of management, the consolidated condensed financial statements include the adjustments necessary to present fairly the information required to be set forth therein. Certain information and note disclosures normally included in financial statements prepared in accordance with generally accepted accounting principles in the United States of America have been condensed or omitted from these statements pursuant to such rules and regulations and, accordingly, these financial statements should be read in conjunction with the audited consolidated financial statements of the Company for the year ended December 31, 2001, included in the Company's Annual Report on Form 10-K. The results for interim periods are not necessarily indicative of the results for the entire year. The Company's historical amounts have been restated to reflect the pooling-of-interests transaction completed during the second quarter of 2001 for the acquisition of Encal Energy Ltd. ("Encal"), the adoption of accounting standards relating to discontinued operations and the presentation of trading revenue on a net versus gross basis.

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, capitalization of interest and depletion, depreciation and impairment of natural gas and petroleum property and equipment. See the "Critical Accounting Policies" subsection in the Management's Discussion and Analysis of Financial Condition and Results of Operations in the Company's Annual Report on Form 10-K for the year ended December 31, 2001, for a further discussion of the Company's significant estimates.

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 Emerging Issues Task Force ("EITF") No. 91-6, "Revenue Recognition of Long Term Power Sales Contracts," and are recognized 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, Calpine Energy Services, L.P. ("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. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." 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 Staff Accounting Bulletin 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 records settlement of its non-trading physical forward contracts on a gross basis. Effective July 1, 2002, the Company now records all gains and losses from derivatives held for trading purposes on 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 in this filing 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 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.

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.

Income from Unconsolidated Investments in Power Projects -- The Company uses the equity method to recognize as revenue its pro rata share of the net income or loss of the unconsolidated investment until such time, if applicable, 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.

Other Revenue -- This includes O&M contract revenue, interest income on loans to power projects, 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 consumed 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.

Derivative Instruments -- Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standards ("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 as further amended by SFAS No. 138, "Accounting for Certain Derivative Instruments and Certain Hedging Activities -- an Amendment of FASB Statement No. 133," together with related guidance from the Derivatives Implementation Group, establishes accounting and reporting standards requiring that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded in the balance sheet as either an asset or liability measured at its fair value unless exempted from derivative treatment as a normal purchase and sale. The statement requires that changes in the derivative's fair value be recognized currently in earnings unless specific hedge criteria are met, and requires that a company must formally document, designate, and assess the effectiveness of transactions that receive hedge accounting.

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 ("OCI") 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 perfectly effective, such amounts recorded in earnings will be equal and offsetting.

SFAS No. 133 requires that as of the date of initial adoption, the difference between the fair value of derivative instruments and the previous carrying amount of these derivatives be recorded in net income or OCI, as appropriate, as the cumulative effect of a change in accounting principle.

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 4 for more information.

In June 2001 the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations," which amends SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies." SFAS No. 143 addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. SFAS No. 143 is effective for financial statements issued for fiscal years beginning after June 15, 2002. The Company has not completed its assessment of the impact of SFAS No. 143.

On January 1, 2002, the Company adopted SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," 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 (of which there are none to date) are included in discontinued operations net of tax. See Note 7 - Discontinued Operations, for further information.

In April 2002 the FASB issued SFAS No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections." 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 has 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 or loss to other (income)/expense. The provisions related to SFAS No. 13 shall be effective for transactions occurring after May 15, 2002. All other provisions shall be 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 extinguishment of debt may have a material effect on future presentation of its financial statements but no impact on net income.

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, potentially.

In October 2002 the EITF discussed EITF Issue No. 02-3, "Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities." 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 Task Force 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. The Company expects that further clarifications may be forthcoming from the EITF on this issue that could have an affect on the presentation of the Company's financial statements. The Company has not completed its assessment of the impact that EITF No. 02-3 will have on its financial statements. Effective July 1, 2002, the Company reclassified certain revenue amounts and cost of revenue in all periods presented in its Statement of Operations as follows (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
Amounts previously classified as:				
Sales of purchased power	$ 203,878	$ 373,969	$ 737,921	$ 483,381
Sales of purchased gas	54,081	7,851	67,970	16,789
Purchased power expense	201,549	369,660	734,616	479,315
Purchased gas expense	54,848	6,659	68,517	14,937
Cost of oil and natural gas burned by power plants (fuel expense)	(5,283)	(11,199)	(12,518)	(15,422)
Net amount reclassified to:				
Realized revenue on power and gas trading transactions, net	$ 6,845	$ 16,700	$ 15,276	$ 21,340
Amounts previously classified as:				
Electric power derivative mark-to-market gain (loss)	(1,068)	13,577	9,201	83,316
Natural gas derivative mark-to-market gain (loss)	(9,889)	(6,449)	(15,153)	24,546
Net amount reclassified to:				
Unrealized mark-to-market gain (loss) on power and gas trading transactions, net	$ (10,957)	$ 7,128	$ (5,952)	$ 107,862

Reclassifications -- Prior period amounts in the consolidated condensed financial statements have been reclassified where necessary to conform to the 2002 presentation.

3. Property, Plant and Equipment, and Capitalized Interest

Property, plant and equipment, net, consisted of the following (in thousands):

	September 30, 2002	December 31, 2001
Buildings, machinery and equipment	$ 8,655,369	$ 4,743,319
Oil and gas properties, including pipelines	2,165,849	2,043,296
Geothermal properties	395,382	371,156
Other	195,884	114,239
	11,412,484	7,272,010
Less: Accumulated depreciation, depletion and amortization	(1,188,406)	(849,016)
	10,224,078	6,422,994
Land	77,472	80,506
Construction in progress	7,181,850	8,467,580
Property, plant and equipment, net	$ 17,483,400	$ 14,971,080

Construction in progress is primarily attributable to gas-fired power projects under construction including prepayments on gas 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. In March 2002 the Company announced a change in its turbine and construction program that has led to a reduction in the Company's construction in progress. See Note 13 for further discussion.

As of September 30, 2002, the Company has reclassified $204.4 million of equipment costs from construction in progress to 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 $20.7 million charge to project development expense to effect a reduction in the carrying value of such equipment. The Company currently anticipates that some of the equipment will be used for future power plants and others may be sold to third parties. The Company is now in negotiations to restructure contracts for certain of its remaining gas turbines and steam turbines. The Company expects to complete these negotiations in the fourth quarter of 2002. 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. During the three months ended September 30, 2002 and 2001, the total amount of interest capitalized was $123.2 million and $121.6 million, including $22.2 million and $29.0 million, respectively, of interest incurred on funds borrowed for specific construction projects and $101.0 million and $92.6 million, respectively, of interest incurred on general corporate funds used for construction. During the nine months ended September 30, 2002 and 2001, the total amount of interest capitalized was $457.3 million and $341.2 million, including $94.3 million and $94.9 million, respectively, of interest incurred on funds borrowed for specific construction projects and $363.0 million and $246.3 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 2002, compared to 2001, 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 are the Company's senior notes, the Company's term loan facility and $600 million and $400 million revolving credit facilities.

4. 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 the transitional goodwill impairment test as required and determined that the fair value of the reporting units holding 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, and 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):

	Three Months Ended September 30,					
	2002			2001		
		Per Share			Per Share	
	Amount	Diluted	Basic	Amount	Diluted	Basic
Reported income before discontinued operations and cumulative effect of accounting changes	$ 144,397	$ 0.33	$ 0.38	$ 313,496	$ 0.86	$ 1.03
Add: Goodwill amortization	--	--	--	221	--	--
Pro forma income before discontinued operations and cumulative effect of accounting changes	144,397	0.33	0.38	313,717	0.86	1.03
Discontinued operations and cumulative effect of accounting changes, net of tax	16,950	0.03	0.05	7,303	0.02	0.02
Pro forma net income	$ 161,347	$ 0.36	$ 0.43	$ 321,020	$ 0.88	$ 1.05

	Nine Months Ended September 30,					
	2002			2001		
		Per Share			Per Share	
	Amount	Diluted	Basic	Amount	Diluted	Basic
Reported income before discontinued operations and cumulative effect of accounting changes	$ 132,646	$ 0.37	$ 0.38	$ 510,807	$ 1.47	$ 1.69
Add: Goodwill amortization	--	--	--	562	--	--
Pro forma income before discontinued operations and cumulative effect of accounting changes	132,646	0.37	0.38	511,369	1.47	1.69
Discontinued operations and cumulative effect of accounting changes, net of tax	26,950	0.08	0.08	37,320	0.10	0.12
Pro forma net income	$ 159,596	$ 0.45	$ 0.46	$ 548,689	$ 1.57	$ 1.81

Recorded goodwill, by segment, as of September 30, 2002 and December 31, 2001, was (in thousands):

	September 30, 2002	December 31, 2001
Electric Generation and Marketing	$ 29,348	$ 29,375
Oil and Gas Production and Marketing	--	--
Corporate, Other and Eliminations	--	--
Total	$ 29,348	$ 29,375

Subsequent goodwill impairment tests will be performed, at a minimum, in the fourth quarter 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 September 30, 2002 Carrying Amount	As of September 30, 2002 Accumulated Amortization	As of December 31, 2001 Carrying Amount	As of December 31, 2001 Accumulated Amortization
Patents	5	$ 485	$ (206)	$ 485	$ (134)
Power sales agreements	14	159,563	(103,874)	159,563	(86,646)
Fuel supply and fuel management contracts	26	22,198	(3,882)	22,198	(3,216)
Geothermal lease rights	20	19,493	(325)	19,493	(250)
Steam purchase agreement	14	5,073	(386)	-	-
Other	5	852	(58)	277	(25)
Total		$ 207,664	$ (108,731)	$ 202,016	$ (90,271)

Amortization expense of other intangible assets was $6.4 million and $5.9 million in the three months ended September 30, 2002 and 2001, respectively, and $18.5 million and $17.8 million in the nine months ended September 30, 2002 and 2001, respectively. Assuming no future impairments of these assets or additions as the result of acquisitions, annual amortization expense will be $21.7 million for the twelve months ended December 31, 2002, $5.5 million in 2003, $5.0 million in 2004, $5.0 million in 2005 and $4.9 million in 2006.

5. Financing

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 other 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 September 30, 2002, there was $117.5 million in borrowings outstanding under this agreement.

On May 14, 2002, the Company's subsidiary, Calpine California Energy Finance, LLC, entered into an 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. $50.0 million was repaid on August 7, 2002, and the remaining $50.0 million (which is classified as current project financing) is payable on November 25, 2002.

On May 31, 2002, the Company increased its two-year secured bank term loan to $1.0 billion from $600.0 million, and reduced the aggregate size of its secured corporate revolving credit facilities to $1.0 billion (the $600 million and $400 million facilities, respectively,) from $1.4 billion. At September 30, 2002, the Company had $1.0 billion in funded borrowings outstanding under the term loan facility, and $250.0 million in funded borrowings outstanding, and $595.2 million in outstanding letters of credit under the revolving credit facilities. The revolving credit facilities expire in 2003. However, any letters of credit under the $600 million revolving credit facility can be extended for one year at the Company's option. In 2004 the $1 billion term loan matures.

On August 22, 2002, the Company completed a $106 million non-recourse project financing for the construction of its 300 megawatt Blue Spruce Energy Center. At September 30, 2002, the Company had $47.2 million in funded borrowings under this non-recourse construction and term-loan facility.

In November 2003 and 2004 the Company's $1.0 billion and $2.5 billion secured revolving construction financing facilities will mature, requiring the Company to repay or refinance this indebtedness. At September 30, 2002, there was $969.8 million and $2,493.6 million outstanding, respectively, under these facilities.

For financing activity subsequent to September 30, 2002, see Note 15 - Subsequent Events.

6. 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$10.00 per unit, to initially yield 9.35% per annum. The Fund indirectly owns interests in two of Calpine's Canadian power generating assets, one of which is under construction, and will make a loan to a Calpine subsidiary which owns Calpine's other Canadian power generating asset. 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). This brings the total gross amount of the initial public offering to Cdn$264.5 million (US$169.4 million) as of September 30, 2002.

The Company intends to retain a substantial interest and operating and management role in the Calpine Power Income Fund and the Fund assets and, accordingly, the financial results of the Fund are consolidated in the Company's financial statements. At September 30, 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.

7. 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 assets, which serves primarily to strengthen the Company's balance sheet through repayment of debt. Set forth below are all of the Company's announced and/or completed asset disposals by reportable segment as of September 30, 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 million (US$81 million).

In September 2002 the Company announced an agreement with Pengrowth Corporation, administrator of Pengrowth Energy Trust, to sell substantially all of the Company's British Columbia oil and gas properties. The sale was subsequently completed on October 1, 2002, for approximately Cdn$387.5 million (US$243.7 million). See Note 15 - Subsequent Events - for further discussion.

In September 2002 the Company executed a Purchase and Sale Agreement with Goldking Energy Corporation to sell all of the oil and gas properties in Drake Bay Field located in Plaquemines Parish, Louisiana for approximately $3 million. The sale was subsequently completed on October 31, 2002.

Electric Generation and Marketing

On June 28, 2002, the Company executed a definitive agreement with Wisconsin Public Service for the sale to Wisconsin Public Service of the Company's 180-megawatt DePere Energy Center. The closing of this transaction is subject to certain conditions. One of the conditions, the receipt of regulatory approval by the State of Wisconsin, was satisfied on September 16, 2002. The sale is expected to close during the fourth quarter of 2002. Upon completion of the sale, Wisconsin Public Service will pay the Company $120.4 million for the DePere facility, and the existing power purchase agreement will be terminated.

The tables below present significant components of the Company's income from discontinued operations for the three and nine months ended 2002 and 2001, respectively (in thousands):

	Three Months Ended September 30, 2002			Three Months Ended September 30, 2001		
	Electric Generation and Marketing	Oil and Gas Production and Marketing	Total	Electric Generation and Marketing	Oil and Gas Production and Marketing	Total
Total revenue.....	$ 4,440	$26,369	$ 30,809	$ 4,463	$ 30,168	$ 34,631
Gain on disposal before taxes.....	--	22,996	22,996	--	--	--
Income from discontinued operations before taxes.....	588	26,037	26,625	35	12,171	12,206
Income from discontinued operations, net of tax.....	287	16,663	16,950	20	7,283	7,303

	Nine Months Ended September 30, 2002			Nine Months Ended September 30, 2001		
	Electric Generation and Marketing	Oil and Gas Production and Marketing	Total	Electric Generation and Marketing	Oil and Gas Production and Marketing	Total
Total revenue.....	$ 10,091	$73,931	$ 84,022	$ 10,936	$117,926	$128,862
Gain on disposal before taxes.....	--	22,996	22,996	--	--	--
Income from discontinuing operations before taxes.....	1,858	40,151	42,009	(293)	60,951	60,658
Income from discontinued operations, net of tax.....	1,112	25,838	26,950	(177)	36,461	36,284

The table below presents the assets and liabilities held for sale on the Company's balance sheet as of September 30, 2002 and December 31, 2001, respectively:

	September 30, 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 held for sale.....	$ --	$ 19,920	$ 19,920	$ --	$ 9,484	$ 9,484
Long-term assets held for sale.....	76,489	164,985	241,474	70,304	238,159	308,463
Total assets held for sale.....	$ 76,489	$184,905	$261,394	$ 70,304	$247,643	$317,947
Current liabilities held for sale..	$ --	$ 4,522	$ 4,522	$ --	$ 4,576	$ 4,576
Long-term liabilities held for sale	5,983	--	5,983	5,947	--	5,947
Total liabilities held for sale..	$ 5,983	$ 4,522	$ 10,505	$ 5,947	$ 4,576	$ 10,523

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 No. 87-24"). Also in accordance with EITF 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. For the three months ended September 30, 2002 and 2001, the Company allocated interest expense of $2.8 million and $1.3 million, respectively, to its discontinued operations. For the nine months ended September 30, 2002 and 2001, the Company allocated interest expense of $5.8 million and $3.1 million, respectively, to its discontinued operations.

8. 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 financial 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. 98-10. 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 that are not deemed normal purchases and sales can be designated as hedges of the underlying consumption of gas or production of electricity.

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 September 30, 2002, for the Company's derivative instruments:

	Interest Rate Derivative Instruments	Currency Derivative Instruments	Commodity Derivative Instruments Net	Total Derivative Instruments
Current derivative assets	$ --	$ --	$ 556,259	$ 556,259
Long-term derivative assets	--	--	548,510	548,510
Total assets	$ --	$ --	$ 1,104,769	$ 1,104,769
Current derivative liabilities	$ 13,486	$ 2,645	$ 433,390	$ 449,521
Long-term derivative liabilities	28,881	10,992	509,696	549,569
Total liabilities	$ 42,367	$ 13,637	$ 943,086	$ 999,090
Net derivative assets (liabilities)	$ (42,367)	$ (13,637)	$ 161,683	$ 105,679

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:

o 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, thereby creating an imbalance between net OCI and net derivative assets and liabilities.

o 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.

o 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 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 September 30, 2002 (in thousands):

Net derivative assets	$ 105,679
Derivatives not designated as cash flow hedges and recognized hedge ineffectiveness	(170,507)
Cash flow hedges terminated prior to maturity	(283,448)
Deferred tax asset attributable to accumulated other comprehensive loss on cash flow hedges	126,305
Accumulated OCI from unconsolidated investees	16,625
Other reconciling items	2,108
Accumulated other comprehensive loss from derivative instruments, net of tax	$ (203,238)

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 September 30, 2002.

	September 30, 2002	
	Gross	Net
Current derivative assets	$ 884,615	$ 556,259
Long-term derivative assets	682,683	548,510
Total derivative assets	$ 1,567,298	$ 1,104,769
Current derivative liabilities	$ 761,746	$ 433,390
Long-term derivative liabilities	643,869	509,696
Total derivative liabilities	$ 1,405,615	$ 943,086
Net commodity derivative assets	$ 161,683	$ 161,683

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 three and nine months ended September 30, 2002 and 2001, respectively (in thousands):

	Three Months Ended September 30,					
	2002			2001		
	Hedge Ineffectiveness	Undesignated Derivatives	Total	Hedge Ineffectiveness	Undesignated Derivatives	Total
Natural gas derivatives.....	$(2,141)	$(7,748)	$ (9,889)	$(2,346)	$(4,103)	$(6,449)
Power derivatives.....	(3,072)	2,004	(1,068)	--	13,577	13,577
Interest rate derivatives (1).....	(236)	--	(236)	(95)	--	(95)
Total.....	$(5,449)	$(5,744)	$(11,193)	$(2,441)	$ 9,474	$ 7,033

	Nine Months Ended September 30,					
	2002			2001		
	Hedge Ineffectiveness	Undesignated Derivatives	Total	Hedge Ineffectiveness	Undesignated Derivatives	Total
Natural gas derivatives.....	$ 584	$(15,737)	$(15,153)	$(5,818)	$ 30,364	$ 24,546
Power derivatives.....	(4,296)	13,497	9,201	--	83,316	83,316
Interest rate derivatives (1).....	(577)	--	(577)	(112)	--	(112)
Total.....	$(4,289)	$ (2,240)	$ (6,529)	$(5,930)	$113,680	$107,750

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(1) 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 three and nine months ended September 30, 2002 and 2001, respectively (in thousands):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
Natural gas and crude oil derivatives	$ (43,224)	$ (25,913)	$(118,267)	$ 2,067
Power derivatives	90,747	126,930	252,527	120,742
Interest rate derivatives	(3,385)	(9,085)	(8,012)	(9,085)
Foreign currency derivatives	--	--	(2,794)	--
Total derivatives	$ 44,138	$ 91,932	$ 123,454	$ 113,724

As of September 30, 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 1/2, and 12 years, for commodity, foreign currency and interest rate derivative instruments, respectively. The Company estimates that pre-tax losses of $87.5 million would be reclassified from accumulated OCI into earnings during the twelve months ended September 30, 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.

	Q4 2002	2003	2004	2005	2006	2007 & After	Total
Crude oil OCI (1)	$ (2,614)	$ (1,763)	$ --	$ --	$ --	$ --	$ (4,377)
Gas OCI	(1,607)	(145,939)	(62,061)	(61,243)	(26,978)	2,842	(294,986)
Power OCI	21,767	51,765	7,332	1,827	3,651	(1,149)	85,193
Interest rate OCI	(16,128)	(18,091)	(14,539)	(11,995)	(10,303)	(29,965)	(101,021)
Foreign currency OCI	(144)	(2,034)	(2,004)	(1,973)	(1,966)	(6,233)	(14,354)
Total pre-tax OCI	$ 1,274	$(116,062)	$ (71,272)	$ (73,384)	$ (35,596)	$ (34,505)	$(329,545)

(1) Amounts in crude oil OCI relate to certain of the Company's oil and gas discontinued operations. These amounts will continue to be recognized into income from discontinued operations until the disposals have been completed. See Note 7 - Discontinued Operations - for further discussion.

9. Comprehensive Income (Loss)

Comprehensive income (loss) is the total of net income (loss) and all other non-owner changes in equity. Comprehensive income (loss) includes net income
(loss) and unrealized gains and losses from derivative instruments that qualify as cash flow hedges. The Company reports accumulated other comprehensive loss in its consolidated balance sheet. The tables below detail the changes in the Company's accumulated OCI balance and the components of the Company's comprehensive income (loss) (in thousands):

	Accumulated Other Comprehensive Income (Loss) At September 30, 2002			
	Cash Flow Hedges	Foreign Currency Translation	Total	Comprehensive Income (Loss)
Accumulated other comprehensive loss at December 31, 2001	$ (183,377)	$ (43,197)	$ (226,574)	
Net loss for the three months ended March 31, 2002				$ (74,267)
Cash flow hedges:				
Comprehensive pre-tax gain on cash flow hedges before reclassification adjustment during the three months ended March 31, 2002	120,610			
Reclassification adjustment for gain included in net loss for the three months ended March 31, 2002	(48,699)			
Income tax provision for the three months ended March 31, 2002	(28,153)			
	43,758		43,758	43,758
Foreign currency translation loss for the three months ended March 31, 2002		(25,170)	(25,170)	(25,170)
Total comprehensive loss for the three months ended March 31, 2002				$ (55,679)
Accumulated other comprehensive loss at March 31, 2002	$ (139,619)	$ (68,367)	$ (207,986)	
Net income for the three months ended June 30, 2002				$ 72,516
Cash flow hedges:				
Comprehensive pre-tax gain on cash flow hedges before reclassification adjustment during the three months ended June 30, 2002	$ 47,855			
Reclassification adjustment for gain included in net income for the three months ended June 30, 2002	(30,617)			
Income tax provision for the three months ended June 30, 2002	(6,736)			
	10,502		$ 10,502	10,502
Foreign currency translation gain for the three months ended June 30, 2002		$ 78,777	78,777	78,777
Total comprehensive income for the three months ended June 30, 2002				161,795
Total comprehensive income for the six months ended June 30, 2002				$ 106,116
Accumulated other comprehensive income (loss) at June 30, 2002	$ (129,117)	$ 10,410	$ (118,707)	

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	Accumulated Other Comprehensive Income (Loss) At September 30, 2002			
	Cash Flow Hedges	Foreign Currency Translation	Total	Comprehensive Income (Loss)
Net income for the three months ended September 30, 2002.....				$ 161,347
Cash flow hedges:				
Comprehensive pre-tax loss on cash flow hedges before reclassification adjustment during the three months ended September 30, 2002.....	$ (74,813)			
Reclassification adjustment for gain included in net income for the three months ended September 30, 2002.....	(44,138)			
Income tax benefit for the three months ended September 30, 2002.....	44,830			
	(74,121)		$ (74,121)	(74,121)
Foreign currency translation loss for the three months ended September 30, 2002.....		$ (37,489)	(37,489)	(37,489)
Total comprehensive income for the three months ended September 30, 2002.....				49,737
Total comprehensive income for the nine months ended September 30, 2002.....				$ 155,853
Accumulated other comprehensive loss at September 30, 2002.....	$ (203,238)	$ (27,079)	$ (230,317)	

	Accumulated Other Comprehensive Income (Loss) At September 30, 2001			
	Cash Flow Hedges	Foreign Currency Translation	Total	Comprehensive Income (Loss)
Accumulated other comprehensive loss at December 31, 2000.....	$ --	$ (23,085)	$ (23,085)	
Net loss for the three months ended March 31, 2001				$ 119,663
Cash flow hedges:				
Comprehensive pre-tax loss on cash flow hedges before reclassification adjustment during the three months ended March 31, 2001.....	(69,134)			
Reclassification adjustment for gain included in net loss for the three months ended March 31, 2001.....	(17,047)			
Income tax provision for the three months ended March 31, 2001.....	32,611			
	(53,570)		(53,570)	(53,570)
Foreign currency translation gain for the three months ended March 31, 2001.....		14,694	14,694	14,694
Total comprehensive income for the three months ended March 31, 2001.....				$ 80,787
Accumulated other comprehensive loss at March 31, 2001.....	$ (53,570)	$ (8,391)	$ (61,961)	
Net income for the three months ended June 30, 2001.....				$ 107,665
Cash flow hedges:				
Comprehensive pre-tax gain on cash flow hedges before reclassification adjustment during the three months ended June 30, 2001.....	$ 263,714			
Reclassification adjustment for gain included in net income for the three months ended June 30, 2001.....	(4,745)			
Income tax provision for the three months ended June 30, 2001.....	(102,047)			
	156,922		$ 156,922	156,922
Foreign currency translation loss for the three months ended June 30, 2001.....		$ (16,550)	(16,550)	(16,550)
Total comprehensive income for the three months ended June 30, 2001.....				248,037
Total comprehensive income for the six months ended June 30, 2001.....				$ 328,824
Accumulated other comprehensive income at June 30, 2001.....	$ 103,352	$ (24,941)	$ 78,411	

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	Accumulated Other Comprehensive Income (Loss) At September 30, 2002			
	Cash Flow Hedges	Foreign Currency Translation	Total	Comprehensive Income (Loss)
Net income for the three months ended September 30, 2001.....				$ 320,799
Cash flow hedges:				
Comprehensive pre-tax loss on cash flow hedges before reclassification adjustment during the three months ended September 30, 2001.....	$ (387,558)			
Reclassification adjustment for gain included in net income for the three months ended September 30, 2001.....	(91,932)			
Income tax benefit for the three months ended September 30, 2001.....	188,578			
	(290,912)		$ (290,912)	(290,912)
Foreign currency translation loss for the three months ended September 30, 2001.....		$ (10,659)	(10,659)	(10,659)
Total comprehensive income for the three months ended September 30, 2001.....				19,228
Total comprehensive income for the nine months ended September 30, 2001.....				$ 348,052
Accumulated other comprehensive loss at September 30, 2001.....	$ (187,560)	$ (35,600)	$ (223,160)	

10. Customers

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, and the Company established a bad debt reserve of approximately $2.7 million against NPC receivables. In addition, NPC and SPPC filed with the Federal Energy Regulatory Commission ("FERC") under Section 206 of the Federal Power Act - see Note 13 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 September 30, 2002, the Company had net collection exposures of approximately $35.1 million and $9.6 million with NPC and SPPC, respectively. SPPC is 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 September 30, 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			
	Gross Receivable	Gross Payable	Net Receivable (Payable)	Gross Fair Value (+)	Gross Fair Value (-)	Net Open Positions Value	Total
NPC.....	$ 42.7	$ (14.8)	$ 27.9	$ 20.1	$ (12.9)	$ 7.2	$ 35.1
SPPC.....	6.3	--	6.3	3.3	--	3.3	9.6
Total.....	$ 49.0	$ (14.8)	$ 34.2	$ 23.4	$ (12.9)	$ 10.5	$ 44.7

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 reportedly experienced 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 through October 20, 2002, the Company has established a partial reserve in OCI in the balance sheet against the fair value of its open contract position with NRG Power Marketing, Inc. 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 September 30, 2002, is summarized below (in millions):

	Receivables/Payables			Open Positions			
	Gross Receivable	Gross Payable	Net Receivable (Payable)	Gross Fair Value (+)	Gross Fair Value (-)	Net Open Positions Value	Total
NRG Power Marketing, Inc.....	$ 3.0	$ (0.0)	$ 3.0	$ 6.3	$ (0.5)	$ 5.8	$ 8.8

PSM License Receivable

In December 2001 PSM and a Dutch power services company entered into a perpetual world-wide license agreement for certain PSM proprietary reverse-flow venturi technology. The license fee, while earned upfront, is payable over the period from January 2002 through March 2004. The Company recognized the license fee of $11 million (less imputed interest on the receivable) as income in December 2001. As of the date of this filing, the Company has a receivable of $6 million, with no payments past due. The indirect parent of the Dutch company, a German holding company, filed for insolvency in Germany in July 2002 and the direct parent of the Dutch company has also filed for insolvency. However, the Dutch company has assured the Company that it has not and currently does not expect to file for insolvency. The Company has been further assured in a letter from the German holding company dated July 11, 2002, that the Dutch company expects to continue the license arrangement and to meet its obligations thereunder. Based on the Company's evaluation of these and other factors, the Company has not established a reserve against the related receivable but will continue to closely monitor the situation.

Aquila Merchant Services, Inc.

On November 13th, 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. Currently Aquila has an investment grade rating with two of the three major credit rating agencies. We believe that a downgrade in Aquila's credit rating could trigger additional collateral requirements under Aquila's and AMS's contractual commitments. We currently buy and sell electricity and natural gas from Aquila and AMS under a variety of contractual arrangements. We account for certain of our contractual arrangements with AMS as derivatives under SFAS No. 133 and, accordingly, record the fair value of the open positions under these contracts in our financial statements. We also have tolling arrangements with AMS on our Acadia facility and with Aquila on our Aries facility under which they deliver gas to, and purchase electricity from, us with 20 and 15.5 year terms, respectively. These tolling agreements are not subject to derivative accounting. We also have outstanding receivable and payable balances with Aquila and AMS. The net value of the positions in our balance sheet at September 30, 2002, is summarized below (in millions):

	Receivables/Payables			Open Positions			
	Gross Receivable	Gross Payable	Net Receivable (Payable)	Gross Fair Value (+)	Gross Fair Value (-)	Net Open Positions Value	Total
AMS and Aquila.....	$ 4.0	$ (10.6)	$ (6.6)	$ 53.8	$ (5.1)	$ 48.7	$ 42.1

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.

11. 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 interest expense and 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).

	Periods Ended September 30,					
	2002			2001		
	Net Income	Shares	EPS	Net Income	Shares	EPS
THREE MONTHS:						
Basic earnings per common share:						
Income before discontinued operations and cumulative effect of a change in accounting principle	$ 144,397	376,957	$ 0.38	$ 313,496	304,666	$ 1.03
Discontinued operations, net of tax	16,950		0.05	7,303		0.02
Cumulative effect of a change in accounting principle, net of tax	--	--	--	--	--	--
Net income	$ 161,347	376,957	$ 0.43	$ 320,799	304,666	$ 1.05
Diluted earnings per common share:						
Common shares issuable upon exercise of stock options using treasury stock method		5,650			13,886	
Income before dilutive effect of certain convertible securities, discontinued operations and cumulative effect of a change in accounting principle	$ 144,397	382,607	0.38	$ 313,496	318,552	$ 0.98
Dilutive effect of certain convertible securities	14,326	99,377	(0.05)	12,435	58,153	(0.12)
Income before discontinued operations and cumulative effect of a change in accounting principle	158,723	481,984	0.33	325,931	376,705	0.86
Discontinued operations, net of tax	16,950		0.03	7,303		0.02
Cumulative effect of a change in accounting principle, net of tax	--	--	--	--	--	--
Net income	$ 175,673	481,984	$ 0.36	$ 333,234	376,705	$ 0.88

	Periods Ended September 30,					
	2002			2001		
	Net Income	Shares	EPS	Net Income	Shares	EPS
NINE MONTHS:						
Basic earnings per common share:						
Income before discontinued operations and cumulative effect of a change in accounting principle	$ 132,646	346,816	$ 0.38	$ 510,807	302,649	$ 1.69
Discontinued operations , net of tax	26,950		0.08	36,284		0.12
Cumulative effect of a change in accounting principle, net of tax	--	--	--	1,036	--	--
Net income	$ 159,596	346,816	$ 0.46	$ 548,127	302,649	$ 1.81
Diluted earnings per common share:						
Common shares issuable upon exercise of stock options using treasury stock method		8,761			15,231	
Income before dilutive effect of certain convertible securities, discontinued operations and cumulative effect of a change in accounting principle	$ 132,646	355,577	$ 0.37	$ 510,807	317,880	$ 1.61
Dilutive effect of certain convertible securities	--	--	--	33,204	52,353	(0.14)
Income before discontinued operations and cumulative effect of a change in accounting principle	132,646	355,577	0.37	544,011	370,233	1.47
Discontinued operations, net of tax	26,950		0.08	36,284		0.10
Cumulative effect of a change in accounting principle, net of tax	--	--	--	1,036	--	--
Net income	$ 159,596	355,577	$ 0.45	$ 581,331	370,233	$ 1.57

For the three and nine months ended September 30, 2002 and for the three and nine months ended September 30, 2001, respectively, the effect of 28,149, 124,755, 2,693 and 2,683 thousand unexercised employee stock options, Company-obligated mandatorily redeemable convertible preferred securities of subsidiary trusts, Zero Coupons and Convertible Senior Notes Due 2006, were not included in the computation of diluted shares outstanding because such inclusion would have been antidilutive.

12. Stock Compensation

The Company accounts for qualified stock compensation under APB Opinion No. 25, "Accounting for Stock Issued to Employees." On August 27, 2002, the Company announced that, effective January 1, 2003, we intended to adopt SFAS No. 123, "Accounting for Stock-Based Compensation." Had compensation cost been determined consistent with the methodology of SFAS No. 123, which provides for the accounting of options as compensation expense, the Company's net income and earnings per share would have been changed to the following pro forma amounts (in thousands, except per share amounts):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
Net income				
As reported	$ 161,347	$ 320,799	$ 159,596	$ 548,127
Pro Forma	155,020	312,922	127,934	527,042
Earnings per share data:				
Basic earnings per share				
As reported	$ 0.43	$ 1.05	$ 0.46	$ 1.81
Pro Forma	0.41	1.03	0.37	1.74
Diluted earnings per share				
As reported	$ 0.36	$ 0.88	$ 0.45	$ 1.57
Pro Forma	0.35	0.86	0.36	1.51

For the three and nine months ended September 30, 2002 and 2001, respectively, the fair value of options granted was $3.56 and $5.09, and $13.79 and $22.67 on the dates of grant using the Black-Scholes option pricing model with the following weighted-average assumptions: expected dividend yields of 0%, expected volatility of 97% for the three and nine months ended September 30,

2002, and 76% for the three and nine months ended September 30, 2001, risk-free interest rates of 2.34% for the three months ended September 30, 2002, 2.66% for the nine months ended September 30, 2002, and 5.02% for the three and nine months ended September 30, 2001, and expected option terms after vesting of 2 years and 3 years for the three and nine months ended September 30, 2002 and 1 year for the three and nine months ended September 30, 2001.

13. Commitments and Contingencies

Capital Expenditures -- On March 12, 2002, the Company announced a new turbine program that reduces previously forecasted capital spending by approximately $1.2 billion in 2002 and $1.8 billion in 2003. As a result of the turbine order cancellations and the cancellation of certain other equipment, the Company recorded a pre-tax charge of $168.5 million in the first quarter of 2002, based primarily on forfeited prepayments to date and an immaterial cash payment pursuant to contract terms. The Company recorded an additional pre-tax charge of $3.7 million in the third quarter of 2002, based on final resolution of this cancellation.

Discussions continue with certain of the Company's major equipment manufacturers to restructure its existing orders for gas and steam turbines. The Company expects to complete this process by the end of 2002.

Litigation--

Securities Derivative Lawsuit. 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 captioned Johnson v. Cartwright, et al. (No. CV803872), 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. The Company has filed a demurrer asking the court to dismiss the complaint on the ground that the shareholder plaintiff lacks standing to pursue claims on behalf of the Company. The individual defendants have filed a demurrer asking the court to dismiss the complaint on the ground that it fails to state any claims against them. The Company considers this lawsuit to be without merit and intends to vigorously defend against it.

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. Gustaferro v. Calpine Corp., filed April 18, 2002, is a purported class action on behalf of purchasers of Calpine stock between February 6, 2001, and December 13, 2001. The eleven other actions, captioned Local 144 Nursing Home Pension Fund v. Calpine Corp., Lukowski v. Calpine Corp., Hart v. Calpine Corp., Atchison v. Calpine Corp., Laborers Local 1298 v. Calpine Corp., Bell v. Calpine Corp., Nowicki v. Calpine Corp., Pallotta v. Calpine Corp., Knepell v. Calpine Corp., Staub v. Calpine Corp., and Rose v. Calpine Corp., were filed between March 18, 2002, and April 23, 2002. The complaints in these eleven actions are virtually identical--they were filed by three law firms, in conjunction with other law firms as co-counsel. 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. The Company expects that these actions, as well as any related actions that may be filed in the future, will be consolidated by the court into a single securities class action.

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 to 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 offering, and seeks an unspecified amount of damages, in addition to other forms of relief. The Company expects that this action will either be consolidated with the above-referenced actions or will proceed as a parallel related action before the same judge presiding over the other actions.

The Company considers the allegations against Calpine in each of these lawsuits to be without merit, and intends to defend vigorously against them.

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., was served on May 2, 2002, by T&E Pastorino Nursery, on behalf of itself and all others similarly situated. This purported class action complaint 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 five other similar complaints for violations of Section 17200 captioned Bronco Don Holdings, LLP. v. Duke Energy Marketing and Trading, et al.; Century Theatres, Inc. v. Allegheny Energy Supply Company, LLC; RDJ Farms, Inc. v. Allegheny Energy Supply Company, LLC; J&M Karsant Family Limited Partnership v. Duke Energy Trading and Marketing, LLC; and Leo's Day and Night Pharmacy v. Duke Energy Trading and Marketing, LLC. All six of these cases have been removed in a multidistrict litigation proceeding from the various state courts in which they were originally filed to federal court, where a motion is now pending to transfer and consolidate these cases for pretrial proceedings with other cases in which the Company is not named as a defendant. In addition, plaintiffs in the T&E Pastorino Nursery 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.

California Department of Water Resources Case. On May 1, 2002, California State Senator Tom McClintock and others filed a complaint against Vikram Budhraja, 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 Budhraja, who negotiated the contracts on behalf of 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 Company considers the allegations against Calpine in this lawsuit to be without merit, and intends to vigorously defend against them.

Nevada Section 206 Complaint. On December 4, 2001, NPC and SPPC filed a complaint with the 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.

Emissions Credits Lawsuit. As described in previous reports, 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 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 dismissed its complaint against 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.

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.

14. Operating Segments

The Company's primary operating segments are power generation; oil and gas production and marketing; and corporate activities and other. Power generation includes the development, acquisition, ownership and operation of power production facilities, the sale of electricity and steam and electricity hedging, balancing, optimization and trading activity. Oil and gas production and marketing includes the ownership and operation of gas fields, gathering systems and gas pipelines for internal gas consumption, third party sales and oil and gas hedging, balancing, optimization and trading activity. Corporate activities and other consists primarily of financing activities, general and administrative costs and consolidating eliminations. This presentation constitutes a change from prior presentation in that management reviews results from segments inclusive of hedging activity, in contrast to the prior view of hedging activity along product line (gas hedging for power plants is now in power generation, versus oil and gas production and marketing). Certain costs related to company-wide functions are allocated to each segment. However, interest on corporate debt is maintained at corporate and is not allocated to the segments. Due to the integrated nature of the business segments, estimates and judgments have been made in allocating certain revenue and expense items. The Company evaluates performance of these operating segments based upon several criteria including gross profit, which is reflected below.

	Power Generation		Oil and Gas Production and Marketing		Corporate, Other and Eliminations		Total	
	2002	2001	2002	2001	2002	2001	2002	2001
	(in thousands)							
For the three months ended September 30, 2002 and 2001:								
Revenue	$2,412,458	$2,465,384	$ 88,201	$ 62,185	$ (5,649)	$ (7,418)	$2,495,010	$2,520,151
Gross profit	352,601	497,879	10,869	16,762	(1,138)	6,504	362,332	521,145
Income (loss) before provision for taxes	292,317	478,888	9,993	10,894	(109,507)	(36,982)	192,803	452,800
Discontinued operations, net of tax	287	20	16,663	7,283	--	--	16,950	7,303
Merger expense	--	--	--	--	--	--	--	--
Equipment cancellation cost	3,714	--	--	--	--	--	3,714	--

	Power Generation		Oil and Gas Production and Marketing		Corporate, Other and Eliminations		Total	
	2002	2001	2002	2001	2002	2001	2002	2001
	(in thousands)							
For the nine months ended September 30, 2002 and 2001:								
Revenue	$5,331,664	$5,063,070	$ 249,588	$340,696	$ 5,490	$ (99,000)	$5,586,742	$5,304,766
Gross profit	754,348	865,388	37,910	190,080	(14,917)	(7,384)	777,341	1,048,084
Income (loss) before provision for taxes	517,185	795,509	(40,159)	131,850	(305,575)	(138,391)	171,451	788,968
Discontinued operations, net of tax	1,112	(177)	25,838	36,461	--	--	26,950	36,284
Merger expense	--	--	--	41,627	--	--	--	41,627
Equipment cancellation cost	172,185	--	--	--	--	--	172,185	--

	Power Generation	Oil and Gas Production and Marketing	Corporate, Other and Eliminations	Total
	(in thousands)			
Total assets:				
September 30, 2002	$18,334,658	$ 4,061,421	$ 293,247	$22,689,326
December 31, 2001	$12,572,848	$ 3,503,075	$ 5,253,629	$21,329,552

For the three months ended September 30, 2002 and 2001, there were intersegment revenues of approximately $144.9 million and $15.9 million, respectively. For the nine months ended September 30, 2002 and 2001, there were intersegment revenues of approximately $217.3 million and $100.8 million, respectively. The elimination of these intersegment revenues, which primarily relate to the use of internally procured gas for the Company's power plants, are included in the Corporate and Other reporting segment.

15. Subsequent Events

In October 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$243.7 million). Of the total consideration, the Company received US$155.3 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 the Company of US$203.2 million in aggregate principal amount of the Company's debt securities. As a result of the transaction, the Company will record a US$41.5 million pre-tax gain on the sale of the properties before any gains on the repurchase of debt. The Company used approximately US$50.4 million of proceeds to repay amounts outstanding under its US$1.0 billion term loan.

The debt securities delivered to the Company by Pengrowth Corporation comprised:

Debt Security	Principal Amount
7-7/8% Senior Notes Due 2008.....	$ 19.5 million
7-3/4% Senior Notes Due 2009.....	20.2 million
8-5/8% Senior Notes Due 2010.....	42.4 million
8-1/2% Senior Notes Due 2011.....	121.1 million
Total.....	$ 203.2 million

Item 2. Management's Discussion and Analysis of Financial Condition and Results of Operations.

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 newly-competitive 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 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 counterparties to enter into transactions with it and its inability to obtain credit or capital in desired amounts or on favorable terms. All information set forth in this filing is as of November 14, 2002, and Calpine undertakes no duty to update this information. Readers should carefully review the "Risk Factors" section in documents filed with the Securities and Exchange Commission.

We file annual, quarterly and special 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. The content of our website is not a part of this report. You may request a copy of these 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.

Selected Operating Information

Set forth below is certain selected operating information for our power plants and steam fields, for which results are consolidated in our statements of operations. Results vary for the three and nine months ended September 30, 2002, as compared to the same periods in 2001, for the reasons discussed more fully throughout this Management's Discussion and Analysis of Financial Condition and Results 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 revenue includes, 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 thermal sales and other revenue (revenues in thousands).

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
	(in thousands, except production and pricing data)			
Power Plants:				
Electricity and steam ("E&S") revenue:				
Energy	$ 485,431	$ 488,621	$ 1,542,957	$ 1,266,601
Capacity	409,115	177,928	600,955	420,138
Thermal and other	52,780	43,957	125,980	118,150
Subtotal	$ 947,326	$ 710,506	$ 2,269,892	$ 1,804,889
E&S revenue from discontinued operations	4,440	4,463	10,091	10,936
Spread on sales of purchased power (1)	223,136	258,217	486,601	283,684
Adjusted E&S revenue	$ 1,174,902	$ 973,186	$ 2,766,584	$ 2,099,509
Megawatt hours produced	23,375,000	13,687,000	53,809,000	28,804,000
All-in electricity price per megawatt hour generated	$ 50.26	$ 71.10	$ 51.41	$ 72.89

(1) From hedging, balancing and optimization activities related to our generating assets. The spread on trading activities is excluded.

Credit restrictions on certain Calpine Energy Services, L.P. ("CES") activities in 2002 has negatively impacted the volume of its hedging, balancing and optimization activities and these restrictions could cause further reductions of such activities in the future.

Megawatt hours produced at the power plants increased 71% and 87% for the three and nine months ended September 30, 2002, as compared to the same periods in 2001. This was primarily due to the addition of power plants that commenced commercial operation subsequent to September 30, 2001. The decrease in average all-in electricity price per megawatt hour generated in 2002 reflects the softening market conditions in 2002 for power. The information above is related to our generating assets and excludes trading activities which are discussed in the Results of Operations and Performance Metrics below.

Results of Operations

Set forth below is a table summarizing the dollar amounts and percentages of our total revenue for the three and nine months ended September 30, 2002 and 2001, 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):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
Total revenue	$ 2,495,010	$ 2,520,151	$ 5,586,742	$ 5,304,766
Sales of purchased power for hedging and optimization	1,282,976	1,653,088	2,526,555	2,680,488
As a percentage of total revenue	51.4%	65.6%	45.2%	50.5%
Sales of purchased gas for hedging and optimization	231,893	56,916	666,095	412,782
As a percentage of total revenue	9.3%	2.3%	11.9%	7.8%
Total cost of revenue ("COR")	2,132,678	1,999,006	4,809,401	4,256,682
Purchased power expense for hedging and optimization	1,059,840	1,394,871	2,039,954	2,396,804
As a percentage of total COR	49.7%	69.8%	42.4%	56.3%
Purchased gas expense for hedging and optimization	220,775	52,856	678,192	389,814
As a percentage of total COR	10.4%	2.6%	14.1%	9.2%

The accounting requirements under Staff Accounting Bulletin ("SAB") 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 Agent" require us to show most of our physical delivery hedging contracts on a gross basis (as opposed to netting sales and cost of revenue).

Rules in effect throughout 2002 and 2001 associated with the NEPOOL market in New England 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 in the United States of America 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 decrease in 2002 is primarily due to lower prices in 2002, partially offset by increased volume.

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2002	2001	2002	2001
	(in thousands)			
Sales into NEPOOL ISO from power we generated	$ 97,852	$ 99,819	$ 211,889	$ 221,275
Sales into NEPOOL ISO from hedging and other activity	33,964	67,776	78,770	124,420
Total sales into NEPOOL	$ 131,816	$ 167,595	$ 290,659	$ 345,695
Total purchases from NEPOOL ISO	$ 113,659	$ 152,463	$ 274,838	$ 319,023

Three Months Ended September 30, 2002, Compared to Three Months Ended September 30, 2001.

Revenue -- Total revenue decreased slightly to $2,495.0 million for the three months ended September 30, 2002, compared to $2,520.2 million for the same period in 2001.

Electric generation and marketing revenue decreased to $2,230.3 million in 2002 compared to $2,363.6 million in 2001. Approximately $236.8 million of the $133.3 million variance was due to electricity and steam sales, which increased due to our growing portfolio of power plants. Generation increased 71% but average pricing dropped by 29%. Our revenue for the period ended September 30, 2002, includes the consolidated results of additional facilities that we completed construction on subsequent to September 30, 2001. However, sales of purchased power decreased by $370.1 million due to lower power prices and industry-wide credit restrictions on risk management activities in 2002, which has resulted in a lower volume of hedging and optimization activity.

Oil and gas production and marketing revenue increased to $253.7 million in 2002 compared to $111.6 million in 2001. The increase is due to a $175.0 million increase in sales of purchased gas, offset by a $32.9 million decrease in oil and gas sales to third parties primarily due to increased internal consumption.

Trading revenue, net -- Trading revenue, net decreased from $23.8 million in 2001 to $(4.1) million in 2002. In the three months ended September 30, 2001, we recognized significant mark-to-market gains from power contracts in a market area where we did not have generation assets. Due to lower power prices and industry-wide credit restrictions on risk management and trading activities in 2002, such opportunities and other trading activities have been greatly restricted.

Cost of revenue -- Cost of revenue increased to $2,132.7 million in 2002 compared to $1,999.0 million in 2001. Approximately $167.9 million of the increase relates to the cost of gas purchased by our energy services organization due to increased price hedging, balancing and optimization activities. Fuel expense increased 60%, from $327.9 million in 2001 to $525.5 million in 2002, due to an increase of 81% in gas-fired megawatt hours generated as offset by slightly lower gas prices in 2002 and an improvement in average heat rate of our generation portfolio. Plant operating expense increased by 51% from $93.7 million to $141.3 million but, expressed per MWh of generation, decreased from $6.85/MWh to $6.04/MWh as economies of scale are being realized due to the increase in the average size of our plants. Depreciation, depletion and amortization expense increased by 47%, from $80.0 million to $117.6 million, due primarily to additional power facilities in consolidated operations at September 30, 2002, as compared to the same period in 2001. These increases were somewhat offset by a $335.0 million decrease in purchased power expense that was caused by lower power prices and by industry-wide credit restrictions on risk management activities in 2002, which has resulted in a lower volume of hedging and optimization activity.

Project development expense -- Project development expense increased $19.0 million as we expensed approximately $7.7 million in costs related to the cancellation or indefinite suspension of certain development projects.

General and administrative expense -- General and administrative expense increased to $57.3 million during the third quarter 2002 as compared to $29.4 million in the prior year. The increase is due to the growth of our infrastructure needed to support operations, whose output has grown by approximately 87% and due to severance costs relating to reduction of excess staffing. In the comparable period of 2001, we revised our estimate of bonus expense to reflect a higher mix of stock options versus cash in compensation.

Interest expense -- Interest expense increased 139% to $113.8 million for the three months ended September 30, 2002, from $47.7 million for the same period in 2001. Interest expense increased primarily due to the issuance of the Convertible Senior Notes Due 2006 and additional senior notes in the fourth quarter of 2001 and due to the fact that interest expense on construction projects stops being capitalized once the project goes into commercial operations and a greater number of projects were in commercial operation in the three months ended September 30, 2002, than in the three months ended September 30, 2001. Interest capitalized in 2002 and 2001 was $123.2 million and $121.6 million, respectively. 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.

Interest income -- Interest income decreased to $10.8 million for the three months ended September 30, 2002, compared to $21.1 million for the same period in 2001. This decrease is due primarily to lower cash balances and interest rates in 2002.

Other -- Other income increased by $25.9 million in the three months ended September 30, 2002, compared to the same period in 2001. In the 2002 period we recognized $38.6 million from the termination of a power sales agreement and $2.9 million in Canadian foreign exchange gains. These were partially offset by $4.7 million of letter of credit fees and a $3.0 million loss on the sale of two turbines.

Provision for income taxes -- The provision for income taxes as a percent of income before provision for income taxes decreased from approximately 31% to 25% for the three months ended September 30, 2002 and 2001, respectively. The decrease in rates was due to our expansion into Canada and the United Kingdom, our cross border financings in October 2001, our revision of estimated year end earnings for 2002, and our revision of tax accruals.

Discontinued operations, net of tax -- Discontinued operations, net of tax for the three months ended September 30, 2002, was $17.0 million as compared to $7.3 million in 2001. The 2002 amount includes a $12.9 million after-tax gain on the sale of certain oil and gas properties. See Note 7 to the Condensed Consolidated Financial Statements for further discussion.

Nine Months Ended September 30, 2002, Compared to Nine Months Ended September 30, 2001.

Revenue -- Total revenue increased to $5,586.7 million for the nine months ended September 30, 2002, compared to $5,304.8 million for the same period in 2001.

Electric generation and marketing revenue increased by $311.0 million to $4,796.4 million in 2002 compared to $4,485.4 million in 2001. Sales of purchased power decreased by $153.9 million due to lower power prices and industry-wide credit restrictions on risk management activities in 2002, which has resulted in a lower volume of hedging and optimization activity. Electricity and steam sales increased by $465.0 million due to our growing portfolio of power plants. Generation increased 87%, but average pricing dropped to moderate

revenue growth. Our revenue for the period ended September 30, 2002, includes the consolidated results of additional facilities that we completed construction on subsequent to September 30, 2001.

Oil and gas production and marketing revenue increased to $755.7 million in 2002 compared to $652.7 million in 2001. The increase is primarily due to a $253.3 million increase in the sales of purchased gas offset by a $150.4 million decrease in oil and gas sales to third parties because of much lower average natural gas pricing in 2002 and increased internal consumption.

Trading revenue, net -- Trading revenue, net decreased from $129.2 million in 2001 to $9.3 million in 2002. In the nine months ended September 30, 2001, we recognized a significant mark-to-market gain from power contracts in a market area where we did not have generation assets. Due to lower power prices and industry-wide credit restrictions on risk management and trading activities in 2002, such opportunities and other trading activities have been greatly restricted.

Cost of revenue -- Cost of revenue increased to $4,809.4 million in 2002 compared to $4,256.7 million in 2001. Approximately $288.4 million of the $552.7 million increase relates to the cost of gas purchased by our energy services organization due to increased price hedging, balancing and optimization activities. Fuel expense increased 43%, from $846.2 million in 2001 to $1,208.1 million in 2002, due to a 104% increase in gas-fired megawatt hours generated as offset by significantly lower gas prices, increased usage of internally produced gas and an improved average heat rate of our generation portfolio in 2002. Plant operating expense increased by 52% from $246.0 million to $374.5 million but, expressed per MWh of generation, decreased from $8.54/MWh to $6.96/MWh as economies of scale are being realized due to the increase in the average size of our plants. Royalty expense decreased $10.1 million between periods due to a decrease in revenue for The Geysers geothermal plants. Depreciation, depletion and amortization expense increased by 56%, from $199.5 million to $310.9 million, due primarily to additional power facilities in consolidated operations at September 30, 2002, as compared to the same period in 2001. Operating lease expense increased 31% due to sale/leaseback transactions subsequent to September 30, 2001.

Project development expense -- Project development expense increased 139% from $25.1 million for the nine months ended September 30, 2001, as compared to $60.0 million for the same period in 2002, as we expensed $28.0 million in costs related to the cancellation or indefinite suspension of certain development projects.

Equipment cancellation cost -- The pre-tax equipment cancellation charge of $172.2 million in the nine months ended September 30, 2002, was as a result of the turbine order cancellations and the cancellation of certain other equipment based primarily on forfeited prepayments to date.

General and administrative expense -- General and administrative expense increased 48% to $170.4 million for the nine months ended September 30, 2002, as compared to $114.9 million for the same period in 2001. The increase was attributable to continued growth in personnel and associated overhead costs necessary to support the overall growth in our operations, in addition to severance costs from the reduction of our work force. General and administrative expense expressed per KWh of generation decreased to $3.17/KWh in 2002 from $3.99/KWh in 2001.

Merger expense -- The merger expense of $41.6 million in the nine months ended September 30, 2001 was a result of the pooling-of-interests transaction with Encal Energy Ltd. that closed on April 19, 2001.

Interest expense -- Interest expense increased 122% to $239.1 million for the nine months ended September 30, 2002, from $107.5 million for the same period in 2001. Interest expense increased primarily due to the issuance of the Convertible Senior Notes Due 2006 and additional senior notes in the second half of 2001 and due to the new plants going into commercial operations at which point capitalization of interest expense ceases. Interest capitalized increased from $341.2 million in the nine months ended September 30, 2001 to $457.3 million in the nine months ended September 30, 2002, due to a larger construction portfolio in 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.

Interest income -- Interest income decreased to $34.0 million for the nine months ended September 30, 2002, compared to $60.9 million for the same period in 2001. This decrease is due primarily to lower cash balances and interest rates in 2002.

Other (income) expense -- Other income increased by $34.0 million in the nine months ended September 30, 2002, compared to the same period in 2001, primarily due to a $38.6 million gain we recognized on the termination of a power sales agreement.

Provision for income taxes -- The provision for income taxes as a percent of income before provision for income taxes decreased from approximately 35% to 23% for the nine months ended September 30, 2002 and 2001, respectively. The decrease in rates was due to our expansion into Canada and the United Kingdom, our cross border financings in April 2001 and October 2001, our revision of estimated year end earnings for 2002, and our revision of tax accruals.

Discontinued operations, net of tax -- Discontinued operations, net of tax was $27.0 million and $36.3 million for the nine months ending September 30, 2002 and 2001, respectively. The decrease in 2002 results, despite a $12.9 million gain on sale of oil and gas properties, reflects substantially higher gas prices in 2001. See Note 7 to the Consolidated Condensed Financial Statements for further discussion.

Cumulative effect of a change in accounting principle - In 2001 the $1.0 million of additional income (net of tax of $0.7 million), is due to the adoption of Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities."

Selected Balance Sheet Information

Unconsolidated Investments in Power Projects -- 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 IPPs 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 Androscoggin Energy Center (32.3% now owned by Calpine); (b) opportunities to co-invest with non-regulated subsidiaries of regulated electric utilities, which under the Public Utility Regulatory Policies Act of 1978, as amended, 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.

Accumulated other comprehensive loss -- The amount of the accumulated other comprehensive loss increased from $(226.6) million at December 31, 2001, to $(230.3) million at September 30, 2002. The change resulted from unrealized losses on derivatives designated as cash flow hedges of $(19.8) million, net of amounts reclassified to net loss and income taxes, and foreign currency translation gain of $16.1 million. See Note 9 for further information.

Liquidity and Capital Resources

General -- The latter half of 2001, and particularly the fourth quarter, saw the beginning of 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. While we were able to access the capital and bank credit markets, as discussed below, we recognize that terms of financing available to us now and in the future may not be attractive to us. To protect against this possibility and due to current market conditions, we have scaled back our capital expenditure program for 2002 and 2003 to enable us to conserve our available capital resources, but remain ready to access the capital markets as demand increases and attractive financing opportunities arise.

To date, we have obtained cash from our operations; borrowings under our facilities and other working capital lines; sale 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 debt obligations, fund acquisitions, develop and construct power generation facilities, finance capital expenditures, support our hedging, balancing, optimization and trading activities at CES, repay debt, 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 timing of 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 repay debt, rather than to pay cash dividends.

Factors that could affect our liquidity and capital resources are also discussed in the "Risk Factors" section of our Annual Report on Form 10-K for the year ended December 31, 2001.

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

	Nine Months Ended September 30,	
	2002	2001
	(in thousands)	
Beginning cash and cash equivalents	$ 1,525,417	$ 596,077
Net cash provided by (used in):		
Operating activities	785,015	476,005
Investing activities	(3,197,790)	(6,085,999)
Financing activities	1,544,775	5,490,291
Effect of exchange rates changes on cash and cash equivalents	2,277	--
Net increase (decrease) in cash and cash equivalents	(865,723)	(119,703)
Ending cash and cash equivalents	$ 659,694	$ 476,374

Operating activities for the nine months ended September 30, 2002, provided net cash of $785.0 million, compared to $476.0 million for the nine months ended September 30, 2001. The cash provided by operating activities for the nine months ended September 30, 2002, consisted of a $420.2 million decrease in operating assets, primarily relating to a $472.1 million decrease in accounts receivable, and current derivative assets and other current assets. This was offset by a $494.4 million decrease in operating liabilities, primarily related to derivative activity. A primary factor causing the significant increase in cash flow from operations in the nine months ended September 30, 2002, in comparison to the same period in 2001, is the realization of approximately $222.3 million of pre-bankruptcy petition PG&E receivables in the first quarter of 2002, which helped our operating cash flow performance and, similarly, the failure to collect those receivables in the first nine months of 2001, which reduced operating cash flow in that period.

Investing activities for the nine months ended September 30, 2002, consumed net cash of $3.2 billion, primarily due to construction costs and capital expenditures including gas turbine generator costs and associated capitalized interest, $64.7 million of advances to joint ventures including associated capitalized interest for investments in power projects under construction, $84.8 million of capitalized project development costs including associated capitalized interest, and a $14.5 million increase in restricted cash. This was partially offset by $125.1 million of proceeds from sales of physical assets.

Financing activities for the nine months ended September 30, 2002, provided $1.5 billion of net cash consisting of $751.2 million of proceeds from the offering of common stock, $100.0 million of proceeds from the issuance of additional Convertible Senior Notes Due 2006 pursuant to exercise of the initial purchasers' remaining purchase option, $1.3 billion of proceeds from drawings on our term loan and revolving lines of credit, $169.4 million of proceeds from our Canadian Income Trust Offering, and $438.5 million of proceeds from project financing. This was partially offset by $869.7 million for the repurchase of the outstanding Zero Coupons, $75.7 million for the repayment of notes payable and borrowings under our lines of credit, $153.8 million for repayments of project financing, and additional financing costs.

We continue to evaluate current and forecasted cash flow as a basis for funding operating requirements and capital expenditures. In November 2003 and 2004 the Company's $1.0 billion and $2.5 billion secured revolving construction financing facilities will mature, requiring the Company to refinance this indebtedness. At September 30, 2002, there was $969.8 million and $2,493.6 million outstanding, respectively, under these facilities. We believe that we will have sufficient liquidity from cash flow from operations, borrowings available under lines of credit, access to sale/leaseback and other markets, sale of certain assets and cash balances to satisfy all obligations under outstanding indebtedness, and to fund anticipated capital expenditures and working capital requirements for the next twelve months.

Enron Bankruptcy-- During 2001 we, primarily through our CES subsidiary, transacted a significant volume of business with units of Enron Corp. ("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.

We have conducted no business with EPMI or ENA since December 31, 2001. We have terminated all of our 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).

Management believes, based on contractually permissible calculation methodologies, that our gross exposure to Enron and its affiliates will be significantly less than amounts previously disclosed using calculations made under generally accepted accounting principles. We expect that this amount will be offset by CES' losses, damages, attorneys' fees and other expenses arising from the default by Enron.

We are 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, we intend to pursue our rights under our agreements with Enron and its affiliates. Regardless of the outcome, we believe, based upon legal analysis, that we do not have any net collection exposure to Enron and its affiliates as at the date hereof.

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 us by approximately $4.2 million, and we established a bed debt reserve of approximately $2.7 million against NPC receivables. On October 25, 2002, we received approximately $22.2 million from NPC for outstanding payables owed to us for power deliveries made during the period of May 1, 2002 through September 15, 2002. See Part II -- Other Information - Item 1 for further discussion.

As of September 30, 2002, we had net collection exposures of approximately $35.1 million and $9.6 million with NPC and SPPC, respectively. SPPC is paying us currently. Our exposures include open forward power contracts that are reported at fair value on our balance sheet as well as receivable and payable balances relating to prior power deliveries. We are continuing to monitor our exposure and its effect on our financial condition.

NRG Power Marketing, Inc.-- We have 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 Financial Accounting Standards Board ("FASB") Statement of Financial Accounting Standards ("SFAS") No. 133, "Accounting for Derivative Instruments and Hedging Activities." NRG Energy, Inc. has reportedly experienced 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 us through October 20, 2002, we have established a partial reserve in other comprehensive income ("OCI") in the balance sheet against the fair value of our open contract position with NRG Power Marketing, Inc. Our exposure to NRG Power Marketing, Inc. at September 30, 2002, is approximately $8.8 million, net of established reserve. We will continue to closely monitor our position with NRG Power Marketing, Inc. and will adjust the value of the reserve as conditions dictate.

PSM License Receivable -- In December 2001 our wholly owned subsidiary, Power Systems Mfg., LLC ("PSM") and a Dutch power services company entered into a perpetual world-wide license agreement for certain PSM proprietary reverse-flow venturi technology. The license fee, while earned upfront, is payable over the period from January 2002 through March 2004. We recognized the license fee of $11 million (less imputed interest on the receivable) as income in December 2001. As of the date of this filing, we have a receivable of $6 million, with no payments past due. The indirect parent of the Dutch company, a German holding company, filed for insolvency in Germany in July 2002 and the direct parent of the Dutch company has also filed for insolvency. However, the Dutch company has assured us that it has not and currently does not expect to file for insolvency in the near term. We have been further assured in a letter from the German holding company dated July 11, 2002, that the Dutch company expects to continue the license arrangement and to meet its obligations thereunder. Based on our evaluation of these and other factors, we have not established a reserve against the related receivable but will continue to closely monitor the situation.

CES Margin Deposits and Other Credit Support -- As of September 30, 2002, CES had $49.8 million in cash on deposit as margin deposits with third parties related to its business activities and letters of credit outstanding in support of CES business activities of $181.6 million. As of December 31, 2001, CES had deposited $345.5 million in cash as margin deposits with third parties related to its business activities and letters of credit outstanding in support of CES business activities of $259.4 million. 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.

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. Fifteen of these facilities have subsequently achieved full or partial commercial operation as of September 30, 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 reduces 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 $172.2 million in the first nine months of 2002.

Capital Availability -- As a result of the significant contraction in the availability of capital for participants in the energy sector, access to capital for many in the sector, including the Company, has been restricted. While we were able earlier in the year to access the capital and bank credit markets, 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. On April 30, 2002, we completed a public offering of common stock of 66 million shares and priced the offering at $11.50 per share. The proceeds after underwriting fees totaled $734.3 million. The proceeds from the offering were used to repay debt and for general corporate purposes.

On May 14, 2002, our subsidiary, Calpine California Energy Finance, LLC, entered into an 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. $50.0 million was repaid on August 7, 2002, and the remaining $50.0 million (which is classified as current project financing) is payable on November 25, 2002.

On May 31, 2002, we increased our two-year secured bank term loan to $1.0 billion from $600 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. At September 30, 2002, we had $1.0 billion in funded borrowings outstanding under the term loan facility and $250.0 million in funded borrowings outstanding under the revolving credit facilities. Subsequently, $50.4 million of the proceeds of the sale of our British Columbia oil and gas properties to Pengrowth Corporation was applied to repay a portion of the term loan facility.

Letter of credit facilities -- At September 30, 2002, we had approximately $697.0 million 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, $595.2 million were issued under the corporate revolving credit facilities. At December 31, 2001, we had $642.5 million in letters of credit outstanding to support CES risk management, and other operational and construction activities.

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, Broad River 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. We have no ownership or other interest in any of these special-purpose entities. 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.

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. At September 30, 2002, investee debt totaled $652.1 million. Based on our pro rata ownership share of each of the investments, our share would be $242.8 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 Aquila Inc, provided support arrangements until construction was completed to cover cost overruns, if any.

Performance Metrics

In understanding our business, we believe that certain performance metrics are particularly important. These include:

o Average gross profit margin based on non-GAAP revenue and non-GAAP cost of revenue. A high percentage of our recent revenue has 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 of our 2001 Form 10-K). 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 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. However, effective July 1, 2002, 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 with purchased power expense 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 with purchased gas expense 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.

o 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.

o 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.

o Average all-in realized electric price expressed in dollars per MWh generated. We calculate the all-in realized electric price per MWh generated by dividing (a) adjusted E&S 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.

o Average cost of natural gas expressed in dollars per millions of Btu's of fuel consumed. At Calpine, 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.

o 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 Three Months Ended September 30,		Non-GAAP Netted Presentation Three Months Ended September 30,	
	2002	2001	2002	2001
	(In thousands)			
Revenue, Cost of Revenue and Gross Profit				
Revenue:				
Electric generation and marketing revenue				
Electricity and steam revenue(2)	$ 947,326	$ 710,506	$ 1,170,462	$ 968,723
Sales of purchased power for hedging and optimization (2)	1,282,976	1,653,088	--	--
Total electric generation and marketing revenue	2,230,302	2,363,594	1,170,462	968,723
Oil and gas production and marketing revenue				
Oil and gas sales	21,827	54,693	21,827	54,693
Sales of purchased gas for hedging and optimization (2)	231,893	56,916	--	--
Total oil and gas production and marketing revenue	253,720	111,609	21,827	54,693
Trading revenue, net				
Realized revenue on power and gas trading transactions, net	6,845	16,700	6,845	16,700
Unrealized mark-to-market gain (loss) on power and gas transactions, net	(10,957)	7,128	(10,957)	7,128
Total trading revenue, net	(4,112)	23,828	(4,112)	23,828
Income (loss) from unconsolidated investments in power projects	10,176	6,859	10,176	6,859
Other revenue	4,924	14,261	4,924	14,261
Total revenue	2,495,010	2,520,151	1,203,277	1,068,364

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	GAAP Presentation Three Months Ended September 30,		Non-GAAP Netted Presentation Three Months Ended September 30,	
	2002	2001	2002	2001
	(In thousands)			
Cost of revenue:				
Electric generation and marketing expense				
Plant operating expense	141,262	93,709	141,262	93,709
Royalty expense	4,743	5,255	4,743	5,255
Purchased power expense for hedging and optimization (2)	1,059,840	1,394,871	--	--
Total electric generation and marketing expense	1,205,845	1,493,835	146,005	98,964
Oil and gas production and marketing expense				
Oil and gas production expense	22,953	13,009	22,953	13,009
Purchased gas expense for hedging and optimization (2)	220,775	52,856	--	--
Total oil and gas production and marketing expense	243,728	65,865	22,953	13,009
Fuel expense	525,478	327,947	514,360	323,887
Depreciation, depletion and amortization expense	117,568	80,044	117,568	80,044
Operating lease expense	36,520	27,830	36,520	27,830
Other expense	3,539	3,485	3,539	3,485
Total cost of revenue	2,132,678	1,999,006	840,945	547,219
Gross profit	$ 362,332	$ 521,145	$ 362,332	$ 521,145
Gross profit margin	15%	21%	30%	49%

	GAAP Presentation Nine Months Ended September 30,		Non-GAAP Netted Presentation Nine Months Ended September 30,	
	2002	2001	2002	2001
	(In thousands)			
Revenue, Cost of Revenue and Gross Profit				
Revenue:				
Electric generation and marketing revenue				
Electricity and steam revenue(2)	$ 2,269,892	$ 1,804,889	$ 2,756,493	$ 2,088,573
Sales of purchased power for hedging and optimization (2)	2,526,555	2,680,488	--	--
Total electric generation and marketing revenue	4,796,447	4,485,377	2,756,493	2,088,573
Oil and gas production and marketing revenue				
Oil and gas sales	89,585	239,940	89,585	239,940
Sales of purchased gas for hedging and optimization (2)	666,095	412,782	--	--
Total oil and gas production and marketing revenue	755,680	652,722	89,585	239,940
Trading revenue, net				
Realized revenue on power and gas trading transactions, net	15,276	21,340	15,276	21,340
Unrealized mark-to-market gain (loss) on power and gas transactions, net	(5,952)	107,862	(5,952)	107,862
Total trading revenue, net	9,324	129,202	9,324	129,202
Income from unconsolidated investments in power projects	10,499	9,021	10,499	9,021
Other revenue	14,792	28,444	14,792	28,444
Total revenue	5,586,742	5,304,766	2,880,693	2,495,180

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	GAAP Presentation Nine Months Ended September 30,		Non-GAAP Netted Presentation Nine Months Ended September 30,	
	2002	2001	2002	2001
	(In thousands)			
Cost of revenue:				
Electric generation and marketing expense				
Plant operating expense	374,497	246,045	374,497	246,045
Royalty expense	13,092	23,181	13,092	23,181
Purchased power expense for hedging and optimization (2)	2,039,954	2,396,804	--	--
Total electric generation and marketing expense	2,427,543	2,666,030	387,589	269,226
Oil and gas production and marketing expense				
Oil and gas production expense	67,381	62,371	67,381	62,371
Purchased gas expense for hedging and optimization (2)	678,192	389,814	--	--
Total oil and gas production and marketing expense	745,573	452,185	67,381	62,371
Fuel expense	1,208,092	846,195	1,220,189	823,227
Depreciation, depletion and amortization expense	310,943	199,509	310,943	199,509
Operating lease expense	108,917	83,289	108,917	83,289
Other expense	8,333	9,474	8,333	9,474
Total cost of revenue	4,809,401	4,256,682	2,103,352	1,447,096
Gross profit	$ 777,341	$ 1,048,084	$ 777,341	$ 1,048,084
Gross profit margin	14%	20%	27%	42%

	Non-GAAP Netted Presentation Three Months Ended September 30,		Non-GAAP Netted Presentation Nine Months Ended September 30,	
	2002	2001	2002	2001
	(In thousands)			
Other Non-GAAP Performance Metrics				
Average availability and capacity factor:				
Average availability	94%	96%	92%	93%
Average capacity factor or operating rate based on total hours (excluding peakers)	73%	76%	70%	71%
Average heat rate for gas-fired power plants (excluding peakers) (Btu's/kWh):				
Not steam adjusted	7,646	8,069	7,937	8,329
Steam adjusted	7,078	7,415	7,268	7,490
Average all-in realized electric price:				
Adjusted electricity and steam revenue before discontinued operations (in thousands)	$ 1,170,462	$ 968,723	$ 2,756,493	$ 2,088,573
Electricity and steam revenue from discontinued operations	4,440	4,463	10,091	10,936
Adjusted electricity and steam revenue	1,174,902	973,186	2,766,584	2,099,509
MWh generated (in thousands)	23,375	13,687	53,809	28,804
Average all-in realized electric price per MWh	$ 50.26	$ 71.10	$ 51.41	$ 72.89
Average cost of natural gas:				
Fuel expense	$ 514,360	$ 323,887	$ 1,220,189	$ 823,227
Fuel cost elimination	46,957	9,784	116,911	88,455
Fuel expense from discontinued operations	2,418	2,489	4,551	5,564
Adjusted fuel expense	$ 563,735	$ 336,160	$ 1,341,651	$ 917,246
MMBtu of fuel consumed by generating plants (in thousands)	158,420	92,695	377,694	193,838
Average cost of natural gas per MMBtu	$ 3.56	$ 3.63	$ 3.55	$ 4.73
MWh generated (in thousands)	23,375	13,687	53,809	28,804
Average cost of oil and natural gas burned by power plants per MWh	$ 24.12	$ 24.56	$ 24.93	$ 31.84
Average spark spread:				
Adjusted electricity and steam revenue (in thousands)	$ 1,174,902	$ 973,186	$ 2,766,584	$ 2,099,509
Less: Adjusted fuel expense (in thousands)	563,735	336,160	1,341,651	917,246
Spark spread (in thousands)	$ 611,167	$ 637,026	$ 1,424,933	$ 1,182,263
MWh generated (in thousands)	23,375	13,687	53,809	28,804
Average spark spread per MWh	$ 26.14	$ 46.54	$ 26.48	$ 41.05

For the three and nine months ended September 30, 2002 and 2001, trading revenue, net consisted of (dollars in thousands):

		Three Months Ended September 30,		Nine Months Ended September 30,	
		2002	2001	2002	2001
ELECTRICITY					
Realized gain (loss)	Realized revenue on power trading transactions, net..	$ 2,329	$ 4,309	$ 3,305	$ 4,066
Unrealized	Unrealized mark-to-market gain (loss) on power transactions, net.....	(1,068)	13,577	9,201	83,316
Subtotal.....		$ 1,261	$ 17,886	$ 12,506	$ 87,382
GAS					
Realized gain (loss)	Realized revenue on gas trading transactions, net....	$ 4,516	$ 12,391	$ 11,971	$ 17,274
Unrealized	Unrealized mark-to-market gain (loss) on gas transactions, net.....	(9,889)	(6,449)	(15,153)	24,546
Subtotal.....		$ (5,373)	$ 5,942	$ (3,182)	$ 41,820

	Three Months Ended September 30, 2002	Percent of Gross Profit	Three Months Ended September 30, 2001	Percent of Gross Profit
Total trading activity gain (loss).....	$ (4,112)	(1.1)%	$ 23,828	4.6%
Realized gain.....	$ 6,845	1.9%	$ 16,700	3.2%
Unrealized (mark-to-market) gain (loss)(1).....	$ (10,957)	(3.0)%	$ 7,128	1.4%

	Nine Months Ended September 30, 2002	Percent of Gross Profit	Nine Months Ended September 30, 2001	Percent of Gross Profit
Total trading activity gain.....	$ 9,324	1.2%	$ 129,202	12.3%
Realized gain.....	$ 15,276	2.0%	$ 21,340	2.0%
Unrealized (mark-to-market) gain (loss)(1).....	$ (5,952)	(0.8)%	$ 107,862	10.3%

(1) For the three and nine months ended September 30, 2002, the mark-to-market gains shown above as "trading" activity include a net loss on hedge ineffectiveness of $(5,213) and $(3,712), consisting of an ineffectiveness loss on power hedges of $(3,072) and $(4,296) and an ineffectiveness gain (loss) on gas hedges of $(2,141) and $584. For the three and nine months ended September 30, 2001, the mark-to-market gains shown above as "trading" activity include a net loss on hedge ineffectiveness of $(2,346) and $(5,818), consisting of an ineffectiveness gain on power hedges of $0 and $0, and an ineffectiveness loss on gas hedges of $(2,346) and $(5,818).

(2) Following is a reconciliation of GAAP to non-GAAP presentation further to the narrative set forth under this Performance Metrics section ($ in thousands):

	GAAP Balance	Total Net Hedging, Balancing & Optimization Activity	Netted Non-GAAP Balance
Three months ended September 30, 2002			
Electricity and steam revenue	$ 947,326	$ 223,136	$ 1,170,462
Sales of purchased power for hedging and optimization	1,282,976	(1,282,976)	--
Sales of purchased gas for hedging and optimization	231,893	(231,893)	--
Purchased power expense for hedging and optimization	1,059,840	(1,059,840)	--
Purchased gas expense for hedging and optimization	220,775	(220,775)	--
Fuel expense	525,478	(11,118)	514,360
Three months ended September 30, 2001			
Electricity and steam revenue	$ 710,506	$ 258,217	$ 968,723
Sales of purchased power for hedging and optimization	1,653,088	(1,653,088)	--
Sales of purchased gas for hedging and optimization	56,916	(56,916)	--
Purchased power expense for hedging and optimization	1,394,871	(1,394,871)	--
Purchased gas expense for hedging and optimization	52,856	(52,856)	--
Fuel expense	327,947	(4,060)	323,887

	GAAP Balance	Total Net Hedging, Balancing & Optimization Activity	Netted Non-GAAP Balance
Nine months ended September 30, 2002			
Electricity and steam revenue	$ 2,269,892	$ 486,601	$ 2,756,493
Sales of purchased power for hedging and optimization	2,526,555	(2,526,555)	--
Sales of purchased gas for hedging and optimization	666,095	(666,095)	--
Purchased power expense for hedging and optimization	2,039,954	(2,039,954)	--
Purchased gas expense for hedging and optimization	678,192	(678,192)	--
Fuel expense	1,208,092	12,097	1,220,189
Nine months ended September 30, 2001			
Electricity and steam revenue	$ 1,804,889	$ 283,684	$ 2,088,573
Sales of purchased power for hedging and optimization	2,680,488	(2,680,488)	--
Sales of purchased gas for hedging and optimization	412,782	(412,782)	--
Purchased power expense for hedging and optimization	2,396,804	(2,396,804)	--
Purchased gas expense for hedging and optimization	389,814	(389,814)	--
Fuel expense	846,195	(22,968)	823,227

Overview

Summary of Key Activities

Power Plant Development and Construction:

Date	Project	Description
7/02	Freestone Energy Center	Commenced operations
7/02	Bethpage Power Plant Peaker	Commenced operations
7/02	Oneta Energy Center	Partial Commencement of operations
8/02	Yuba City Energy Center	Commenced Operations
8/02	Acadia Energy Center	Commenced Operations
8/02	Hermiston Energy Center	Commenced Operations
8/02	Auburndale Peaking Energy Center	Commenced Operations

10/02 Corpus Christi Energy Center Commenced Operations

Finance

Note Repayments and New Funding:

Date	Approximate Amount	Description
8/7/02	$50.0 million	Repayment of peaker funding
8/22/02	$106.0 million	Non-Recourse project financing for the construction of the Blue Spruce Energy Center
8/29/02	US$147.5 million, Cdn$230 million	Canadian Power Income Fund
8/29/02	US$81.0 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	Canadian Power Income Fund
10/1/02	US$243.7 million, Cdn$387.5 million	Sale of substantially all of our British Columbia oil and gas properties to Calgary, Alberta-based Pengrowth Corporation

Other:

Date	Description
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
10/31/02	Received approximately $3 million from Goldking Energy Corporation for all of the oil and gas properties in Drake Bay Field

California Power Market

On April 22, 2002, we announced that we had renegotiated CES' long-term power contracts with the California Department of Water Resources (the "DWR"). The Office of the Governor of California, the California Public Utilities Commission (the "CPUC"), the California Electricity Oversight Board (the "EOB") and the California Attorney General (the "AG") endorsed the renegotiated contracts and agreed to drop all pending claims against us and our affiliates, including withdrawing the complaint under Section 206 of the Federal Power Act that had been filed by the CPUC and EOB with FERC, and the termination by the CPUC and the EOB of their efforts to seek refunds from us and our affiliates through FERC refund proceedings. In connection with the renegotiation, we have agreed to pay $6 million over three years to the AG to resolve any and all possible claims against us and our affiliates brought by the AG without admitting any liability on the part of the Company.

CES had signed three long-term contracts with DWR in February 2001, comprising two 10-year baseload energy contracts and one 20-year peaking contract. The renegotiation provided for the shortening of the duration of each of the two 10-year, baseload energy contracts by two years and of the 20-year peaker contract by ten years. These changes reduced DWR's long-term purchase obligations. In addition, CES agreed to reduce the energy price on one baseload contract from $61.00 to $59.60 per megawatt-hour, and to convert the energy portion of the peaker contract to gas index pricing from fixed energy pricing. CES also agreed to deliver up to 12.2 million megawatt-hours of additional energy pursuant to the baseload energy contracts in 2002 and 2003. In connection with the renegotiation, CES also agreed with DWR that DWR will have the right to assume and complete four of our projects currently planned for California and in the advanced development stage if we do not meet certain milestones with respect to each project assumed, provided that DWR reimburses us for all construction costs and certain other costs incurred by us to the date DWR assumes the relevant project. Based on the terms of the DWR contracts, we expect to generate over $8.7 billion in revenue between 2002 and 2011 from the DWR contracts.

In addition, the negotiation resolved the dispute with DWR concerning payment of the capacity payment on the peaking contract. The contract provides that through December 31, 2002, CES may earn a capacity payment by committing to supply electricity to DWR from a source other than the peaker units designated in the contract. DWR had made certain assertions challenging CES' right to substitute units or provide replacement energy and had withheld capacity payments in the amount of approximately $15.0 million since December 2001. As part of the renegotiation, we have received payment in full on these withheld capacity payments and will have the right to provide replacement capacity

through December 31, 2002, on the original contract terms. On May 2, 2002, each of the CPUC and the EOB filed a Notice of Partial Withdrawal with Prejudice of Complaint as to Calpine Energy Services, L.P. with the FERC.

Financial Market Risks

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 (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. We enter into commodity financial 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 our vulnerability to reductions in electric prices for the electricity we generate, to reductions in gas prices for the gas we produce, and to increases in gas prices for the fuel we consume in our power plants. We seek to "self-hedge" our gas consumption exposure to an extent with our own gas production position. Any hedging, balancing, or optimization activities that we engage in are directly related to our asset-based business model of owning and operating gas-fired electric power plants and are designed to protect our "spark spread" (the difference between our fuel cost and the revenue we receive for our electric generation). We hedge exposures that arise from the ownership and operation of power plants and related sales of electricity and purchases of natural gas, and we utilize derivatives to optimize the returns we are able to achieve from these assets for our shareholders. From time to time we have entered into contracts considered energy trading contracts under EITF Issue No. 98-10, "Accounting for Contracts Involved in Energy Trading and Risk Management Activities." However, our traders 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, as discussed above, due to industry-wide credit restrictions, our hedging, balancing and optimization activities have been reduced and may be further reduced in the future.

The change in fair value of outstanding commodity derivative instruments from January 1, 2002, through September 30, 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)	(149,536)
Changes in fair value attributable to changes in valuation techniques and assumptions	--
Change in fair value attributable to new contracts and price movements (2)	159,769
Terminated derivatives (2)	239,573
Fair value of contracts outstanding at September 30, 2002 (3)	$ 161,683

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(1) Recognized gains from commodity cash flow hedges of $134.3 million reported in Note 8 of the financial statements and $15.3 million realized gain on trading activity reported in the Statement of Operations under trading revenue, net.

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

(3) Net commodity derivative assets reported in Note 8 of the Notes to Consolidated Financial Statements included in this filing.

The fair value of outstanding derivative commodity instruments at September 30, 2002, based on price source and the period during which the instruments will mature are summarized in the table below (in thousands):

Fair Value Source	2002	2003-2004	2005-2006	After 2006	Total
Prices actively quoted	$ 2,779	$ 102,030	$ --	$ --	$ 104,809
Prices provided by other external sources	16,087	31,777	37,252	--	85,116
Prices based on models and other valuation methods	(276)	3,220	(24,713)	(6,473)	(28,242)
Total fair value	$ 18,590	$ 137,027	$ 12,539	$ (6,473)	$ 161,683

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 function. 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.

The counterparty credit quality associated with the fair value of outstanding derivative commodity instruments at September 30, 2002, and the period during which the instruments will mature are summarized in the table below (in thousands):

Credit Quality (based on October 16, 2002, ratings)	2002	2003-2004	2005-2006	After 2006	Total
Investment grade	$ (7,671)	$ 129,826	$ 14,386	$ (11,089)	$ 125,452
Non-investment grade	26,031	7,814	(1,750)	4,660	36,755
No external ratings	230	(613)	(97)	(44)	(524)
Total fair value	$ 18,590	$ 137,027	$ 12,539	$ (6,473)	$ 161,683

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):

	Fair Value	Fair Value After 10% Adverse Price Change
At September 30, 2002:		
Crude oil	$ (4,664)	$ (9,063)
Electricity	162,086	73,536
Natural gas	4,261	(120,464)
Total	$ 161,683	$ (55,991)

Derivative commodity instruments included in the table are those included in Note 8 to the unaudited Consolidated Condensed 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 physical positions exposed to the cash market. 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 Calpine's 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 65% from December 31, 2001, to September 30, 2002, while the total volume of open power derivative positions decreased 17% 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 OCI, net of tax, or in the statement of operations as an item (gain or loss) of current earnings. As of September 30, 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 nine months ended September 30, 2002, have reflected this. See Note 8 for additional information on derivative activity and also the 2001 Form 10-K for a further discussion of our accounting policies related to derivative accounting. How we account for our derivatives depends upon whether

we have designated the derivative as a cash flow or fair value hedge or not designated the derivative in a hedge relationship. The following accounting applies:

o Changes in the value of derivatives designated as cash flow hedges, net of any ineffectiveness, are recorded to OCI.

o Changes in the value of derivatives designated as fair value hedges are recorded in the statement of operations with the offsetting change in value of the hedge item also recorded in the statement of operations. Any difference between these two entries to the statement of operations represents hedge ineffectiveness.

o The change in value of derivatives not designated in hedge relationships is recorded to the statement of operations.

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 $85.0 million at September 30, 2002. The following tables present our different classes of collateral debt securities by expected maturity date and fair market value as of September 30, 2002, (dollars in thousands):

		Expected Maturity Date					
	Weighted Average Interest Rate	2003	2004	2005	2006	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	105,250	119,015
Total		$ 8,040	$ 6,050	$ 9,800	$ 9,700	$105,250	$138,840

	Fair Market Value
Corporate Debt Securities.....	$ 16,892
Government Agency Debt Securities...	1,994
U.S. Treasury Notes.....	2,223
U.S. Treasury Securities (non-interest bearing).....	83,387
Total.....	$104,496

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 September 30, 2002, (dollars in thousands):

Maturity Date	Weighted Average Notional Principal Amount	Weighted Average Interest Rate (Pay)	Interest Rate (Receive)	Fair Market Value
2008.....	$ 44,250	4.2%	(1)	$ (4,681)
2011.....	51,760	6.9%	3-month US LIBOR	(7,838)
2012.....	117,936	6.5%	3-month US LIBOR	(19,416)
2014.....	67,929	6.7%	3-month US LIBOR	(10,432)
Total.....	$ 281,875	6.3%		$ (42,367)

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

Maturity Date	Notional Principal (Pay/Receive)	Fixed Currency Exchange (Pay/Receive)	Frequency of Currency Exchange	Fair Market Value
2007.....	US$127,763/Cdn$200,000	US$5,545/Cdn$8,750	Semi-annually	$ (9,176)
2008.....	Pound sterling 109,550/Euro 175,000	Pound sterling 5,152/Euro 7,328	Semi-annually	(4,461)
Total.....				$ (13,637)

Debt financing -- Because of the significant capital requirements within our industry, debt financing is often needed to fund our growth. We have used three primary forms of debt: (1) long-term senior notes and related instruments, including the Convertible Senior Notes Due 2006; (2) construction/project financing; and (3) revolving credit and term loan agreements. Our senior notes and related instruments bear fixed interest rates and are generally used to fund acquisitions, replace construction financing for power plants once they achieve commercial operations, and for general corporate purposes. Our 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 bear variable interest rates, and are used exclusively to fund the construction of our power plants. Our revolving credit and term loan facilities bear variable interest rates and are used for general corporate purposes.

The following table summarizes the fair market value of our existing debt financing as of September 30, 2002, (dollars in thousands):

Instrument	Outstanding Balance	Weighted Average Interest Rate	Fair Market Value
Long-term senior notes:			
Senior Notes Due 2005.....	$ 250,000	8.3%	$ 115,000
Senior Notes Due 2006.....	171,750	10.5%	85,875
Senior Notes Due 2006.....	250,000	7.6%	107,500
Convertible Senior Notes Due 2006.....	1,200,000	4.0%	499,788
Senior Notes Due 2007.....	275,000	8.8%	115,500
Senior Notes Due 2007.....	126,120	8.8%	63,060
Senior Notes Due 2008.....	400,000	7.9%	156,000
Senior Notes Due 2008.....	2,030,000	8.5%	832,300
Senior Notes Due 2008.....	172,856	8.4%	58,771
Senior Notes Due 2009.....	350,000	7.8%	136,500
Senior Notes Due 2010.....	750,000	8.6%	300,000
Senior Notes Due 2011.....	2,000,000	8.5%	820,000
Senior Notes Due 2011.....	314,020	8.9%	103,627
Total long-term senior notes.....	$ 8,289,746	7.8%	$ 3,393,921
Construction/project financing:			
Blue Spruce Energy Center project financing.....	$ 47,228	1-month US LIBOR	$ 47,228
Term loan due (due 2004).....	1,000,000	3-month US LIBOR	1,000,000
Calpine Construction Finance Company L.P. (due 2003).....	969,771	1-month US LIBOR	969,771
Calpine Construction Finance Company II, LLC (due 2004).....	2,493,596	1-month US LIBOR	2,493,596
Total long-term construction/project financing.....	$ 4,510,595		$ 4,510,595

Construction/project financing facilities -- In 2003 and 2004, $969.8 million and $2,493.6 million, respectively, under our secured construction financing revolving facilities will mature, requiring us to refinance this indebtedness. We remain confident that we will have the ability to refinance 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. At September 30, 2002, we had $1.0 billion in funded borrowings outstanding under the term loan facility, and $250.0 million in funded borrowings outstanding, and $595.2 million in outstanding letters of credit under the revolving credit facilities. The revolving credit facilities expire in 2003. However, any letters of credit under the $600 million revolving credit facility can be extended for one year at our option. In 2004 the $1 billion term loan matures.

New Accounting Pronouncements

In July 2001 we adopted SFAS No. 141, "Business Combinations," which supersedes 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 our consolidated financial statements.

On January 1, 2002, we 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. We were 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. We completed the transitional goodwill impairment test as required and determined that the fair value of the reporting units holding goodwill exceeded their net carrying values. See Note 4 -- Goodwill and Other Intangible Assets, for further information.

In June 2001 the FASB issued SFAS No. 143, "Accounting for Asset Retirement Obligations," which amends SFAS No. 19, "Financial Accounting and Reporting by Oil and Gas Producing Companies." SFAS No. 143 addresses financial accounting and reporting for obligations associated with the retirement of tangible long-lived assets and the associated asset retirement costs. SFAS No. 143 requires that the fair value of a liability for an asset retirement obligation be recognized in the period in which it is incurred if a reasonable estimate of fair value can be made. SFAS No. 143 is effective for financial statements issued for fiscal years beginning after June 15, 2002. We have not completed our assessment of the impact of SFAS No. 143.

On January 1, 2002, we adopted SFAS No. 144, "Accounting for the Impairment or Disposal of Long-Lived Assets," 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 consolidated financial statements, although certain reclassifications have been made to 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" assts (of which there are none to date) are included in discontinued operations net of tax. See Note 7 - Discontinued Operations, for further information.

In April 2002 the FASB issued SFAS No. 145, "Rescission of FASB Statements No. 4, 44, and 64, Amendment of FASB Statement No. 13, and Technical Corrections." 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" stating that gains or losses from extinguishment of debt that fall outside 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. We have elected early adoption 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 or loss to other (income) expense. The provisions related to SFAS No. 13 shall be effective for transactions occurring after May 15, 2002. The provisions related to SFAS No. 13 shall be effective for transactions occurring after May 15, 2002. All other provisions shall be effective for financial statements issued on or after May 15, 2002, with early adoption encouraged. We believe that the SFAS No. 145 provisions relating to extinguishment of debt may have a material effect on future presentation of our financial statements but no impact on net income.

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)." We 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. We do not believe that SFAS No. 146 will have a material effect on our consolidated financial statements other than timing of exit costs, potentially.

In October 2002 the EITF discussed EITF Issue No. 02-3, "Issues Related to Accounting for Contracts Involved in Energy Trading and Risk Management Activities." 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 Task Force 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. We expect that further clarifications may be forthcoming from the EITF on this issue that could have an affect on the presentation of our financial statements. We have not completed our assessment of the impact that EITF No. 02-3 will have on our financial statements. Effective July 1, 2002, we reclassified certain revenue and cost of revenue to a net rather than gross basis in all periods presented in our Statement of Operations.

Item 3. Quantitative and Qualitative Disclosures About Market Risk.

See "Financial Market Risks" in Item 2.

Item 4. Controls and Procedures.

The Company's senior management, including the Company's Chief Executive Officer and Chief Financial Officer, evaluated the effectiveness of the Company's disclosure controls and procedures within 90 days of the filing date of this quarterly report. Based upon this evaluation, the Company's Chairman, President and Chief Executive Officer along with the Company's Executive Vice President and Chief Financial Officer concluded that the Company's disclosure controls and procedures are effective in ensuring that material information required to be disclosed is included in the reports that it files with the Securities and Exchange Commission. There were no significant changes in the Company's internal controls or, to the knowledge of the management of the Company, in other factors that could significantly affect these controls subsequent to the evaluation date. The certificates required by this item are filed as a part of this Form 10-Q. See Certifications.

PART II - OTHER INFORMATION

Item 1. Legal Proceedings.

Securities Derivative Lawsuit. On December 17, 2001, a shareholder filed a derivative lawsuit on behalf of Calpine against our directors and one of our senior officers. This lawsuit is captioned Johnson v. Cartwright, et al. (No. CV803872), and is pending in the California Superior Court, Santa Clara County. Calpine is 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. We have filed a demurrer asking the court to dismiss the complaint on the ground that the shareholder plaintiff lacks standing to pursue claims on behalf of Calpine. The individual defendants have filed a demurrer asking the court to dismiss the complaint on the ground that it fails to state any claims against them. We consider this lawsuit to be without merit and intend to vigorously defend against it.

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. Gustaferro v. Calpine Corp., filed April 18, 2002, is a purported class action on behalf of purchasers of Calpine stock between February 6, 2001, and December 13, 2001. The eleven other actions, captioned Local 144 Nursing Home Pension Fund v. Calpine Corp., Lukowski v. Calpine Corp., Hart v. Calpine Corp., Atchison v. Calpine Corp., Laborers Local 1298 v. Calpine Corp., Bell v. Calpine Corp., Nowicki v. Calpine Corp., Pallotta v. Calpine Corp., Knepell v. Calpine Corp., Staub v. Calpine Corp., and Rose v. Calpine Corp., were filed between March 18, 2002, and April 23, 2002. The complaints in these eleven actions are virtually identical--they were filed by three law firms, in conjunction with other law firms as co-counsel. 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. We expect that these actions, as well as any related actions that may be filed in the future, will be consolidated by the court into a single securities class action.

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 to 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 our officers and directors, and the underwriters of the offering, and seeks an unspecified amount of damages, in addition to other forms of relief. We expect that this action will either be consolidated with the above-referenced actions or will proceed as a parallel related action before the same judge presiding over the other actions. We consider the allegations against Calpine in each of these lawsuits to be without merit, and we intend to defend vigorously against them.

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., was served on May 2, 2002, by T&E Pastorino Nursery, on behalf of itself and all others similarly situated. This purported class action complaint 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 five other similar complaints for violations of
Section 17200 captioned Bronco Don Holdings, LLP. v. Duke Energy Marketing and Trading, et al.; Century Theatres, Inc. v. Allegheny Energy Supply Company, LLC; RDJ Farms, Inc. v. Allegheny Energy Supply Company, LLC; J&M Karsant Family Limited Partnership v. Duke Energy Trading and Marketing, LLC; and Leo's Day and Night Pharmacy v. Duke Energy Trading and Marketing, LLC. All six of these cases have been removed in a multidistrict litigation proceeding from the various state courts in which they were originally filed to federal court, where a motion is now pending to transfer and consolidate these cases for pretrial proceedings with other cases in which we are not named as a defendant. In addition, plaintiffs in the T&E Pastorino Nursery 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 we intend to vigorously defend against them.

California Department of Water Resources Case. On May 1, 2002, California State Senator Tom McClintock and others filed a complaint against Vikram Budhraja, a consultant to 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 Budhraja, who negotiated the contracts on behalf of 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. We consider the allegations against Calpine in this lawsuit to be without merit and intend to vigorously defend against them.

Nevada Section 206 Complaint. On December 4, 2001, NPC and SPPC filed a complaint with the Federal Energy Regulatory Commission ("FERC") under Section 206 of the Federal Power Act against a number of parties to their power sales agreements, including Calpine. 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.

Emissions Credits Lawsuit. As described in our previous reports, 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 should have been held in our account with U.S. Trust Company ("US Trust"). 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, and we dismissed our complaint against 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.

We are involved in various other claims and legal actions arising out of the normal course of our 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 6. Exhibits and Reports on Form 8-K.

(a)Exhibits

The following exhibits are filed herewith unless otherwise indicated:

EXHIBIT INDEX

EXHIBIT NUMBER	DESCRIPTION
*3.1	Amended and Restated Certificate of Incorporation of Calpine Corporation (a)
*3.2	Certificate of Correction of Calpine Corporation (b)
*3.3	Certificate of Amendment of Amended and Restated Certificate of Incorporation of Calpine Corporation (c)
*3.4	Certificate of Designation of Series A Participating Preferred Stock of Calpine Corporation (b)
*3.5	Amended Certificate of Designation of Series A Participating Preferred Stock of Calpine Corporation (b)
*3.6	Amended Certificate of Designation of Series A Participating Preferred Stock of Calpine Corporation (c)
*3.7	Certificate of Designation of Special Voting Preferred Stock of Calpine Corporation (d)
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(continues next page)

EXHIBIT INDEX
(continued)

EXHIBIT NUMBER	DESCRIPTION
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+99.2	Certification of Robert D. Kelly Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002

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* Incorporated by reference
+ 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.

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(g) 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.

(b) Reports on Form 8-K

The registrant filed the following reports on Form 8-K or Form 8-K/A during the quarter ended September 30, 2002:

Date of Report	Date Filed	Item Reported
July 23, 2002.....	July 24, 2002	Item 5,7
August 1, 2002.....	August 2, 2002	Item 5,7
August 9, 2002.....	August 12, 2002	Item 9
August 26, 2002.....	August 27, 2002	Item 5,7
August 29, 2002.....	August 30, 2002	Item 5,7
September 10, 2002.....	September 11, 2002	Item 5,7
September 19, 2002.....	September 20, 2002	Item 5,7

SIGNATURES

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

CALPINE CORPORATION

Date: November 14, 2002

By: /s/ ROBERT D. KELLY

Robert D. Kelly
Executive Vice President and
Chief Financial Officer
(Principal Financial Officer)

Date: November 14, 2002

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

Charles B. Clark, Jr.
Senior Vice President and
Corporate Controller
(Principal Accounting Officer)

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 quarterly report on Form 10-Q of Calpine Corporation (the "registrant");

2. Based on my knowledge, this quarterly 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 quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly 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 quarterly 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 quarterly 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 quarterly report (the "Evaluation Date"); and

c) Presented in this quarterly 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 the 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 quarterly report whether or not 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: November 14, 2002

/s/ Peter Cartwright

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 quarterly report on Form 10-Q of Calpine Corporation (the "registrant");

2. Based on my knowledge, this quarterly 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 quarterly report;

3. Based on my knowledge, the financial statements, and other financial information included in this quarterly 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 quarterly 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 quarterly 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 quarterly report (the "Evaluation Date"); and

c) Presented in this quarterly 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 the 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 quarterly report whether or not 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: November 14, 2002

/s/ Robert D. Kelly

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

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CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO

SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Calpine Corporation (the "Company") on Form 10-Q for the period ending September 30, 2002, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Peter Cartwright, Chairman, President and Chief Executive Officer of the Company, do hereby certify, pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that, to the best of my knowledge, based upon a review of the Report:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operation of the Company.

Peter Cartwright
Chairman, President and Chief
Executive Officer
Calpine Corporation
November 14, 2002

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO

SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Calpine Corporation (the "Company") on Form 10-Q for the period ending September 30, 2002, as filed with the Securities and Exchange Commission on the date hereof (the "Report"), I, Robert D. Kelly, Executive Vice President and Chief Financial Officer of the Company, do hereby certify, pursuant to 18 U.S.C. ss. 1350, as adopted pursuant to ss. 906 of the Sarbanes-Oxley Act of 2002, that, to the best of my knowledge, based upon a review of the Report:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operation of the Company.

Robert D. Kelly
Executive Vice President and
Chief Financial Officer
Calpine Corporation
November 14, 2002

FOURTH AMENDMENT TO
SECOND AMENDED AND RESTATED CREDIT AGREEMENT

THIS FOURTH AMENDMENT TO SECOND AMENDED AND RESTATED CREDIT AGREEMENT, dated as of September 26, 2002 (herein called this "Amendment"), is entered into by and among CALPINE CORPORATION, a Delaware corporation (herein called the "Company"), the various financial institutions listed on the signature page hereof (the "Lenders") and THE BANK OF NOVA SCOTIA, as administrative agent for the Lenders (herein, in such capacity, called the "Agent").

W I T N E S S E T H:

WHEREAS, the Company, the Lenders and the Agent have heretofore entered into a certain Second Amended and Restated Credit Agreement, dated as of May 23, 2000, as amended by that certain First Amendment and Waiver to Second Amended and Restated Credit Agreement, dated as of April 19, 2001, that certain Second Amendment to Second Amended and Restated Credit Agreement, dated as of March 8, 2002 and that certain Third Amendment to Second Amended and Restated Credit Agreement, dated as of May 9, 2002 (herein called the "Credit Agreement"); and

WHEREAS, the Company, the Lenders and the Agent now desire to amend the Credit Agreement in certain respects, as hereinafter provided; and

NOW, THEREFORE, in consideration of the premises and the mutual agreements herein contained, the Company, the Lenders and the Agent hereby agree as follows:

SECTION 1. Subsection (i) of clause (b) of Section 8.2.6 of the Credit Agreement is hereby amended and restated in its entirety to read as follows:

"(i) make any payment or prepayment of principal of, or make any payment of interest on, any Senior Notes (as such term is defined in the 2002 Credit Agreement) or any Subordinated Debt on any day other than the stated date for such payment or prepayment set forth in the documents and instruments memorializing any Senior Notes or such Subordinated Debt, or which would violate the subordination provisions of any such Subordinated Debt; provided, that the Borrower may so pay or prepay all or a portion of the Senior Notes (as such term is defined in the 2002 Credit Agreement) if either (A) both before and after giving effect thereto, no Default shall have occurred or be continuing and there are no Loans outstanding hereunder or (B) both before and after giving effect thereto, no Default shall have occurred and be continuing and the aggregate amount of all such prepayments shall not exceed 50% of aggregate Net Equity Proceeds received by the Borrower from and after March 8, 2002."

SECTION 2. The effectiveness of this Amendment is conditioned upon receipt by the Agent of all the following documents, each in form and substance satisfactory to the Agent:

(i) This Amendment duly executed by the Company and Required Lenders; and

(ii) Such other documents as the Agent shall have reasonably requested.

SECTION 3. This Amendment shall be deemed to be an amendment to the Credit Agreement, and the Credit Agreement, as amended hereby, is hereby ratified, approved and confirmed in each and every respect. All references to the Credit Agreement in any other document, instrument, agreement or writing shall hereafter be deemed to refer to the Credit Agreement as amended hereby.

SECTION 4. THIS AMENDMENT SHALL BE A CONTRACT MADE UNDER AND GOVERNED BY AND CONSTRUED IN ACCORDANCE WITH THE INTERNAL LAWS OF THE STATE OF NEW YORK. All obligations of the Company and rights of the Lenders and the Agent expressed herein shall be in addition to and not in limitation of those provided by applicable law. Whenever possible each provision of this Amendment shall be interpreted in such manner as to be effective and valid under applicable law, but if any provision of this Amendment shall be prohibited by or invalid under applicable law, such provision shall be ineffective to the extent of such prohibition or invalidity, without invalidating the remainder of such provision or the remaining provisions of this Amendment.

SECTION 5. This Amendment may be executed in any number of counterparts, all of which taken together shall constitute one and the same instrument, and any party hereto may execute this Amendment by signing one or more counterparts.

SECTION 6. This Amendment shall be binding upon the Company, the Lenders and the Agent and their respective successors and assigns, and shall inure to the benefit of the Company, the Lenders and the Agent and the successors and assigns of the Lenders and the Agent.

SECTION 7. THE COMPANY HEREBY KNOWINGLY, VOLUNTARILY AND INTENTIONALLY WAIVES ANY RIGHT TO A TRIAL BY JURY IN ANY ACTION OR PROCEEDING TO ENFORCE OR DEFEND ANY RIGHTS UNDER THIS AMENDMENT OR UNDER ANY AMENDMENT, INSTRUMENT, DOCUMENT OR AGREEMENT DELIVERED OR WHICH MAY IN THE FUTURE BE DELIVERED IN CONNECTION HEREWITH OR ARISING FROM ANY BANKING RELATIONSHIP EXISTING IN CONNECTION WITH THIS AMENDMENT, AND AGREES THAT ANY SUCH ACTION OR PROCEEDING SHALL BE TRIED BEFORE A COURT

AND NOT BEFORE A JURY.

IN WITNESS WHEREOF, the parties hereto have caused this Amendment to be executed by their respective officers thereunto duly authorized as of the day and year first above written.

CALPINE CORPORATION

By: /s/ Michael Thomas
Name: Michael Thomas
Title: Senior Vice President - Treasury

THE BANK OF NOVA SCOTIA, as Agent and Lender

By: /s/ Denis P. O'Meara
Name: Denis P. O'Meara
Title: Managing Director

BAYERISCHE LANDESBANK

By: /s/ C. Stolarski
Name: C. Stolarski
Title: V.P.

By: /s/ C. Wintergerst
Name: C. Wintergerst
Title: V.P.

CIBC INC.

By:

Name:
Title:

CREDIT SUISSE FIRST BOSTON, NEW YORK
BRANCH

By: /s/ James Moran
Name: James Moran
Title: Director

By: /s/ Thomas Murray
Name: Thomas Murray
Title: Directors

BAYERISCHE HYPO-UND VEREINSBANK AG

By:

Name:
Title:

By:
Name:
Title:

ING CAPITAL LLC

By: /s/ Erwin Thomet
Name: Erwin Thomet
Title: Managing Director

By: /s/ G. Dominick Bellamy, Jr.
Name: G. Dominick Bellamy, Jr.
Title: Director

TORONTO DOMINION (TEXAS) INC.

By: /s/ Mark A. Baird
Name: Mark A. Baird
Title: Vice President

UNION BANK OF CALIFORNIA, N.A.

By: /s/ Bryan Read
Name: Bryan Read
Title: Vice President

BANK OF AMERICA, N.A.

By: /s/ Gabriela Millhorn
Name: Gabriela Millhorn
Title: Principal

CREDIT LYONNAIS NEW YORK BRANCH

By: /s/ Martin C. Livingston
Name: Martin C. Livingston
Title: Vice President

DRESDNER BANK AG, NEW YORK AND GRAND CAYMAN BRANCHES

By:

Name:
Title:

By:
Name:
Title:

FLEET NATIONAL BANK

By:

Name:
Title:

FORTIS CAPITAL CORP.

By:

Name:
Title:

End of Filing

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