UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2009

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 No. 001-12079

Calpine Corporation

(A Delaware Corporation)

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

717 Texas Avenue, Suite 1000, Houston, Texas 77002
Telephone: (713) 830-8775

Not Applicable
(Former Address)

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. [X] Yes[ ] No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). [ ] Yes[ ] No

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

Large accelerated filer	[X]		Accelerated filer	[ ]
Non-accelerated filer	[ ]	(Do not check if a smaller reporting company)	Smaller reporting company	[ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). [ ] Yes [X] No

Indicate by check mark whether the registrant has filed all documents and reports required to be filed by Sections 12, 13 or 15(d) of the Securities Exchange Act of 1934 subsequent to the distribution of securities under a plan confirmed by a court. [X] Yes [ ] No

Indicate the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date: 442,151,580 shares of Common Stock, par value $.001 per share, outstanding on July 28, 2009.

CALPINE CORPORATION AND SUBSIDIARIES

REPORT ON FORM 10-Q
For the Quarter Ended June 30, 2009

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Forward-Looking Information

In addition to historical information, this Report contains forward-looking statements within the meaning of Section 27A of the Securities Act and Section 21E of the Exchange Act. We use words such as "believe," "intend," "expect," "anticipate," "plan," "may," "will" and similar expressions to identify forward-looking statements. Such statements include, among others, those concerning our expected financial performance and 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 that a number of risks and uncertainties could cause actual results to differ materially from those anticipated in the forward-looking statements. Such risks and uncertainties include, but are not limited to:

- The uncertain length and severity of the current general financial and economic downturn and its impacts on our business including demand for our power and steam products, the ability of our counterparties to perform under their contracts with us and the cost and availability of capital and credit;
- Fluctuations in prices for commodities such as natural gas and power including the effects of fluctuations in liquidity and volatility in the energy commodities markets including our ability to hedge risks;
- The ability of our customers, suppliers, service providers and other contractual counterparties to perform under their contracts with us;
- Our ability to manage our significant liquidity needs and to comply with covenants under our Exit Credit Facility and other existing financing obligations;
- Financial results that may be volatile and may not reflect historical trends due to, among other things, general economic and market conditions outside of our control;
- Our ability to attract and retain customers and counterparties, including suppliers and service providers, and to manage our customer and counterparty exposure and credit risk, including our commodity positions;
- Competition, including risks associated with marketing and selling power in the evolving energy markets;
- Regulation in the markets in which we participate and our ability to effectively respond to changes in laws and regulations or the interpretation thereof including changing market rules and evolving federal, state and regional laws and regulations including those related to GHG emissions;
- Natural disasters such as hurricanes, earthquakes and floods that may impact our power plants or the markets our power plants serve;
- Seasonal fluctuations of our results and exposure to variations in weather patterns;
- Disruptions in or limitations on the transportation of natural gas and transmission of power;
- Our ability to attract, retain and motivate key employees;
- Our ability to implement our new business plan and strategy;
- Risks related to our geothermal resources, including the adequacy of our steam reserves, unusual or unexpected steam field well and pipeline maintenance requirements and variables associated with the injection of waste water to the steam reservoir;
- Present and possible future claims, litigation and enforcement actions, including our ability to complete the implementation of our Plan of Reorganization;
- The expiration or termination of our PPAs and the related results on revenues;
- Risks associated with the operation, construction and development of power plants including unscheduled outages or delays and plant efficiencies; and
- Other risks identified in this Report and our 2008 Form 10-K.

You should also carefully review other reports that we file with the SEC. We undertake no obligation to update any forward-looking statements, whether as a result of new information, future developments or otherwise.

Where You Can Find Other Information

We file annual, quarterly and other 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 room at 100 F Street, NE, Room 1580, Washington, D.C. 20549. 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 100 F Street, NE, Room 1580, Washington, D.C. 20549-1004. The SEC maintains an Internet website at http://www.sec.gov that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC. Our SEC filings, including exhibits filed herewith, are accessible through the Internet at that website.

Our reports on Forms 10-K, 10-Q and 8-K, and amendments to those reports as well as our other filings with the SEC, are available for download, free of charge, as soon as reasonably practicable after these reports are filed with the SEC, at our website at http://www.calpine.com. The content of our website is not a part of this Report. You may request a copy of our SEC filings, at no cost to you, by writing or telephoning us at: Calpine Corporation, 717 Texas Avenue, Suite 1000, Houston, Texas 77002, attention: Investor Relations, telephone: (713) 830-8775. We will not send exhibits to the documents, unless the exhibits are specifically requested and you pay our fee for duplication and delivery.

DEFINITIONS

As used in this Report, the following abbreviations and terms have the meanings as listed below. Additionally, the terms “Calpine,” “we,” “us” and “our” refer to Calpine Corporation and its consolidated subsidiaries, unless the context clearly indicates otherwise. The term “Calpine Corporation” refers only to Calpine Corporation and not to any of its subsidiaries. Unless and as otherwise stated, any references in this Report to any agreement means such agreement and all schedules, exhibits and attachments in each case as amended, restated, supplemented or otherwise modified to the date of filing this Report.

ABBREVIATION	DEFINITION
2008 Form 10-K	Calpine Corporation’s Annual Report on Form 10-K for the year ended December 31, 2008, filed with the SEC on February 27, 2009, as amended by Amendment No. 1 thereto on Form 10-K/A, filed with the SEC on March 31, 2009
Adjusted EBITDA	EBITDA adjusted to remove the income effects of (a) non-cash losses on sales, dispositions or impairments of assets, (b) any unrealized gains or losses and any non-cash realized gains or losses from accounting for derivatives, (c) non-cash stock compensation expense, (d) operating lease expense, (e) non-cash gains and losses from intercompany foreign currency translations, (f) reorganization items, (g) major maintenance expense, (h) gains or losses on the repurchase or extinguishment of debt and (i) any other extraordinary, unusual or non-recurring income plus our net interest in the Adjusted EBITDA of our unconsolidated investments
AOCI	Accumulated Other Comprehensive Income
ASC	FASB Accounting Standards Codification, effective July 1, 2009, which summarizes all authoritative GAAP into one source
Auburndale	Auburndale Holdings, LLC
Average 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
Average capacity factor (excluding peakers)	The average capacity factor (excluding peakers) is a measure of total actual generation as a percent of total potential generation. It is calculated by dividing (a) total MWh generated by our power plants (excluding peakers) by (b) the product of multiplying (i) the weighted average capacity during the period by (ii) the total hours in the period. The weighted average capacity reflects the seasonally adjusted capacity of our plants (except our mothballed plants) during the period, including any time the plants may not be operating due to scheduled and unscheduled outages for maintenance and repair requirements or because we elect not to generate when power prices are too low or natural gas prices are too high to operate profitably
Bankruptcy Code	U.S. Bankruptcy Code
Bankruptcy Courts	The U.S. Bankruptcy Court and the Canadian Court
BLM	Bureau of Land Management of the U.S. Department of the Interior
Bridge Facility	Bridge Loan Agreement, dated as of January 31, 2008, among Calpine Corporation as borrower, the lenders party thereto, Goldman Sachs Credit Partners L.P., Credit Suisse, Deutsche Bank Securities Inc. and Morgan Stanley Senior Funding Inc., as co-documentation agents, and Goldman Sachs Credit Partners L.P., as administrative agent and collateral agent
Btu	British thermal unit(s), a measure of heat content
CAA	Federal Clean Air Act, United States Code Title 42, Chapter 85
CalGen	Calpine Generating Company, LLC

ABBREVIATION	DEFINITION
CalGen Third Lien Debt	Together, the $680,000,000 Third Priority Secured Floating Rate Notes Due 2011, issued by CalGen and CalGen Finance Corp.; and the $150,000,000 11 1/2% Third Priority Secured Notes Due 2011, issued by CalGen and CalGen Finance Corp., in each case repaid on March 29, 2007
Calpine Equity Incentive Plans	Collectively, the MEIP and the DEIP, which provide for grants of equity awards to Calpine employees and non-employee members of Calpine's Board of Directors
Canadian Court	The Court of Queen's Bench of Alberta, Judicial District of Calgary
Canadian Debtors	The subsidiaries and affiliates of Calpine Corporation that have been granted creditor protection under the CCAA in the Canadian Court
Canadian Effective Date	February 8, 2008, the date on which the Canadian Court ordered and declared that the Canadian Debtors' proceedings under the CCAA were terminated
CCAA	Companies' Creditors Arrangement Act (Canada)
CCFC	Calpine Construction Finance Company, L.P.
CCFC Finance	CCFC Finance Corp.
CCFC Guarantors	Hermiston Power LLC and Brazos Valley Energy LLC, wholly owned subsidiaries of CCFC
CCFC New Notes	The $1.0 billion aggregate principal amount of 8.0% Senior Secured Notes due 2016 issued May 19, 2009, by CCFC and CCFC Finance
CCFC Old Notes	The $415 million total aggregate principal amount of Second Priority Senior Secured Floating Rate Notes Due 2011 issued by CCFC and CCFC Finance, comprising $365 million aggregate principal amount issued August 14, 2003, and $50 million aggregate principal amount issued September 25, 2003, and redeemed on June 18, 2009
CCFC Refinancing	The issuance of the CCFC New Notes on May 19, 2009, pursuant to Rule 144A and Regulation S under the Securities Act, and the related transactions including repayment of the CCFC Term Loans and the redemption of the CCFC Old Notes and CCFCP Preferred Shares
CCFC Term Loans	The $385 million First Priority Senior Secured Institutional Term Loans due 2009 borrowed by CCFC under the Credit and Guarantee Agreement, dated as of August 14, 2003, among CCFC, the guarantors party thereto, and Goldman Sachs Credit Partners L.P., as sole lead arranger, sole bookrunner, administrative agent and syndication agent, and repaid on May 19, 2009
CCFCP	CCFC Preferred Holdings, LLC
CCFCP Preferred Shares	The $300 million of six-year redeemable preferred shares due 2011 issued by CCFCP and redeemed on or before July 1, 2009
CFR	Code of Federal Regulations
CFTC	U.S. Commodities Futures Trading Commission
Channel Energy Center	Our 593 MW natural gas-fired cogeneration power plant located in Houston, Texas
Chapter 11	Chapter 11 of the Bankruptcy Code
Cogeneration	Using a portion or all of the steam generated in the power generating process to supply a customer with steam for use in the customer's operations

ABBREVIATION	DEFINITION
Commodity Collateral Revolver	Commodity Collateral Revolving Credit Agreement, dated as of July 8, 2008, among Calpine Corporation as borrower, Goldman Sachs Credit Partners L.P., as payment agent, sole lead arranger and sole bookrunner, and the lenders from time to time party thereto
Commodity expense	The sum of our GAAP expenses from fuel expense, purchased power and natural gas expense, fuel transportation expense, transmission expense and cash settlements from our marketing, hedging and optimization activities that are included in our mark-to-market activity in fuel and purchased energy expense
Commodity Margin	Non-GAAP financial measure that includes power and steam revenues, capacity revenue, REC revenue and expense, transmission revenue and expenses, fuel and purchased energy expense, and cash settlements from our marketing, hedging and optimization activities that are included in mark-to-market activity, but excludes the unrealized portion of our mark-to-market activity and other revenues
Commodity revenue	The sum of our GAAP revenues from power and steam sales, sales of purchased power and natural gas, capacity revenue, REC revenue, transmission revenue, and cash settlements from our marketing, hedging and optimization activities that are included in our mark-to-market activity in operating revenues
Company	Calpine Corporation, a Delaware corporation, and subsidiaries
Confirmation Order	The order of the U.S. Bankruptcy Court entitled "Findings of Fact, Conclusions of Law, and Order Confirming Sixth Amended Joint Plan of Reorganization Pursuant to Chapter 11 of the Bankruptcy Code," entered December 19, 2007, confirming the Plan of Reorganization pursuant to section 1129 of the Bankruptcy Code
Convertible Senior Notes	Collectively, Calpine Corporation's 4% Contingent Convertible Notes Due 2006, 6% Contingent Convertible Notes Due 2014, 7 3/4% Contingent Convertible Notes Due 2015 and 4 3/4% Contingent Convertible Senior Notes Due 2023
CPUC	California Public Utilities Commission
Deer Park	Deer Park Energy Center Limited Partnership
DEIP	Calpine Corporation 2008 Director Incentive Plan, which provides for grants of equity awards to non-employee members of Calpine's Board of Directors
DIP	Debtor-in-possession
DIP Facility	The Revolving Credit, Term Loan and Guarantee Agreement, dated as of March 29, 2007, among the Company, as borrower, certain of the Company's subsidiaries, as guarantors, the lenders party thereto, Credit Suisse, Goldman Sachs Credit Partners L.P. and JPMorgan Chase Bank, N.A., as co-syndication agents and co-documentation agents, General Electric Capital Corporation, as sub-agent, and Credit Suisse, as administrative agent and collateral agent, with Credit Suisse Securities (USA) LLC, Goldman Sachs Credit Partners L.P., JPMorgan Securities Inc., and Deutsche Bank Securities Inc. acting as Joint Lead Arrangers and Bookrunners
EBITDA	Earnings before interest, taxes, depreciation and amortization
Effective Date	January 31, 2008, the date on which the conditions precedent enumerated in the Plan of Reorganization were satisfied or waived and the Plan of Reorganization became effective
Emergence Date Market Capitalization	Determined as Calpine's Market Capitalization using the 30-day weighted average stock price following the Effective Date
EPA	U.S. Environmental Protection Agency

ABBREVIATION	DEFINITION
ERCOT	Electric Reliability Council of Texas
Exchange Act	U.S. Securities Exchange Act of 1934, as amended
Exit Credit Facility	Credit Agreement, dated as of January 31, 2008, among Calpine Corporation, as borrower, the lenders party thereto, General Electric Capital Corporation, as sub-agent, Goldman Sachs Credit Partners L.P., Credit Suisse, Deutsche Bank Securities Inc., and Morgan Stanley Senior Funding, Inc., as co-syndication agents and co-documentation agents, and Goldman Sachs Credit Partners L.P., as administrative agent and collateral agent
Exit Facilities	Together, the Exit Credit Facility and the Bridge Facility
FASB	Financial Accounting Standards Board
FDIC	Federal Deposit Insurance Corporation
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation
Fremont	Fremont Energy Center, LLC
FSP	FASB Staff Position
GAAP	Generally accepted accounting principles in the United States
GE	General Electric International, Inc.
Geysers Assets	Our geothermal power plant assets located in northern California consisting of 15 operating power plants with 17 turbines and two plants not in operation
GHG	Greenhouse gas(es), primarily CO_2, and including methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs)
Greenfield LP	Greenfield Energy Centre LP
Heat Rate(s)	A measure of the amount of fuel required to produce a unit of power
Hillabee	Hillabee Energy Center, LLC
IRC	Internal Revenue Code
IRS	U.S. Internal Revenue Service
Knock-in Facility	Letter of Credit Facility Agreement, dated as of June 25, 2008, among Calpine Corporation as borrower and Morgan Stanley Capital Services Inc., as issuing bank
KWh	Kilowatt hour(s), a measure of power produced
LIBOR	London Inter-Bank Offered Rate
LSTC	Liabilities subject to compromise
Market Capitalization	Market value of Calpine Corporation common stock outstanding, calculated in accordance with the Calpine Corporation amended and restated certificate of incorporation
Market Heat Rate(s)	The regional power price divided by the corresponding regional natural gas price
MEIP	Calpine Corporation 2008 Equity Incentive Plan, which provides for grants of equity awards to Calpine employees and non-employee members of Calpine's Board of Directors
Metcalf	Metcalf Energy Center, LLC
MMBtu	Million Btu

ABBREVIATION	DEFINITION
MW	Megawatt(s), a measure of plant capacity
MWh	Megawatt hour(s), a measure of power produced
Ninth Circuit	U.S. Court of Appeals for the Ninth Circuit
NOL(s)	Net operating loss(es)
NYMEX	New York Mercantile Exchange
OCI	Other Comprehensive Income
OMEC	Otay Mesa Energy Center, LLC
OTC	Over-the-Counter
PCF	Power Contract Financing, L.L.C.
PCF III	Power Contract Financing III, LLC
Petition Date	December 20, 2005
PG&E	Pacific Gas & Electric Company
Plan of Reorganization	Debtors' Sixth Amended Joint Plan of Reorganization Pursuant to Chapter 11 of the Bankruptcy Code filed by the U.S. Debtors with the U.S. Bankruptcy Court on December 19, 2007, as amended, modified or supplemented through the filing of this Report
PPA(s)	Any term power purchase agreement or other contract for a physically settled sale (as distinguished from a financially settled future, option or other derivative or hedge transaction) of any electric power product, including electric energy, capacity and/or ancillary services, in the form of a bilateral agreement or a written or oral confirmation of a transaction between two parties to a master agreement, including sales related to a tolling transaction in which part of the consideration provided by the purchaser of an electric power product is the fuel required by the seller to generate such electric power
PUCT	Public Utility Commission of Texas
REC	Renewable Energy Credit
RGGI	Regional Greenhouse Gas Initiative
RockGen	RockGen Energy LLC
SDG&E	San Diego Gas & Electric Company
SDNY Court	U.S. District Court for the Southern District of New York
SEC	U.S. Securities and Exchange Commission
Second Circuit	U.S. Court of Appeals for the Second Circuit
Second Priority Debt	Collectively, the Second Priority Notes and Second Priority Senior Secured Term Loans Due 2007
Second Priority Notes	Calpine Corporation's Second Priority Senior Secured Floating Rate Notes Due 2007, 8 1/2% Second Priority Senior Secured Notes Due 2010, 8 3/4% Second Priority Senior Secured Notes Due 2013 and 9 7/8% Second Priority Senior Secured Notes Due 2011
Securities Act	U.S. Securities Act of 1933, as amended
SFAS	Statement of Financial Accounting Standards
SO_2	Sulfur dioxide

ABBREVIATION	DEFINITION
Spark spread(s)	The difference between the sales price of power per MWh and the cost of fuel to produce it
Steam Adjusted Heat Rate	The adjusted Heat Rate for our natural gas-fired power plants, excluding peakers, calculated by dividing (a) the fuel consumed in Btu reduced by the net equivalent Btu in steam exported to a third party by (b) the KWh generated. Steam Adjusted Heat Rate is a measure of fuel efficiency, so the lower our Steam Adjusted Heat Rate, the lower our cost of generation
TCEQ	Texas Commission on Environmental Quality
TMG	Turbine Maintenance Group
Unsecured Senior Notes	Collectively, Calpine Corporation's 7 5/8% Senior Notes due 2006, 10 1/2% Senior Notes due 2006, 8 3/4% Senior Notes due 2007, 7 7/8% Senior Notes due 2008, 7 3/4% Senior Notes due 2009, 8 5/8% Senior Notes due 2010 and 8 1/2% Senior Notes due 2011
U.S.	United States of America
U.S. Bankruptcy Court	U.S. Bankruptcy Court for the Southern District of New York
U.S. Debtors	Calpine Corporation and each of its subsidiaries and affiliates that have filed voluntary petitions for reorganization under Chapter 11 of the Bankruptcy Code in the U.S. Bankruptcy Court, which matters are being jointly administered in the U.S. Bankruptcy Court under the caption *In re Calpine Corporation, et al.*, Case No. 05-60200 (BRL)
VAR	Value-at-risk
VIE(s)	Variable interest entity(ies)
Whitby	Whitby Cogeneration Limited Partnership

PART I — FINANCIAL INFORMATION

Item 1. ***Financial Statements***

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED CONDENSED BALANCE SHEETS
(Unaudited)

	June 30, 2009	December 31, 2008
	(in millions, except share and per share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,482	$ 1,657
Accounts receivable, net of allowance of $40 and $42	822	850
Inventory	171	163
Margin deposits and other prepaid expense	590	776
Restricted cash, current	484	337
Current derivative assets	3,361	3,653
Other current assets	58	64
Total current assets	6,968	7,500
Property, plant and equipment, net	11,760	11,908
Restricted cash, net of current portion	50	166
Investments	204	144
Long-term derivative assets	387	404
Other assets	606	616
Total assets	$ 19,975	$ 20,738
LIABILITIES & STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 588	$ 574
Accrued interest payable	59	85
Debt, current portion	634	716
Current derivative liabilities	3,231	3,799
Income taxes payable	6	5
Other current liabilities	223	437
Total current liabilities	4,741	5,616
Debt, net of current portion	9,955	9,756
Deferred income taxes, net of current portion	93	93
Long-term derivative liabilities	479	698
Other long-term liabilities	209	203
Total liabilities	15,477	16,366
Commitments and contingencies (see Note 12)		
Stockholders' equity:		
Preferred stock, $.001 par value per share; 100,000,000 shares authorized; none issued and outstanding at June 30, 2009, and December 31, 2008	—	—
Common stock, $.001 par value per share; 1,400,000,000 shares authorized; 432,412,629 shares issued and 432,112,939 shares outstanding at June 30, 2009; 429,025,057 shares issued and 428,960,025 shares outstanding at December 31, 2008	1	1
Treasury stock, at cost, 299,690 shares at June 30, 2009, and 65,032 shares at December 31, 2008	(3)	(1)
Additional paid-in capital	12,240	12,217
Accumulated deficit	(7,735)	(7,689)
Accumulated other comprehensive loss	(5)	(158)
Total Calpine stockholders' equity	4,498	4,370
Noncontrolling interest	—	2
Total stockholders' equity	4,498	4,372
Total liabilities and stockholders' equity	$ 19,975	$ 20,738

The accompanying notes are an integral part of these Consolidated Condensed Financial Statements.

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CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED CONDENSED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(in millions, except share and per share amounts)			
Operating revenues	$ 1,471	$ 2,828	$ 3,148	$ 4,779
Cost of revenue:				
Fuel and purchased energy expense	922	2,008	1,937	3,613
Plant operating expense	210	206	458	438
Depreciation and amortization expense	113	108	222	219
Other cost of revenue	20	30	43	62
Total cost of revenue	1,265	2,352	2,660	4,332
Gross profit	206	476	488	447
Sales, general and other administrative expense	48	48	93	96
Income from unconsolidated investments in power plants	(23)	(16)	(40)	(13)
Other operating expense	6	11	9	13
Income from operations	175	433	426	351
Interest expense	207	206	417	625
Interest (income)	(4)	(14)	(10)	(27)
Debt extinguishment costs	33	6	33	13
Other (income) expense, net	—	(5)	4	(2)
Income (loss) before reorganization items and income taxes	(61)	240	(18)	(258)
Reorganization items	3	18	6	(261)
Income (loss) before income taxes	(64)	222	(24)	3
Income tax expense	15	25	24	20
Net income (loss)	(79)	197	(48)	(17)
Add: Net loss attributable to the noncontrolling interest	1	—	2	—
Net income (loss) attributable to Calpine	$ (78)	$ 197	$ (46)	$ (17)
Basic earnings (loss) per common share:				
Weighted average shares of common stock outstanding (in thousands)	485,675	485,004	485,560	485,002
Net income (loss) per common share attributable to Calpine – basic	$ (0.16)	$ 0.41	$ (0.09)	$ (0.04)
Diluted earnings (loss) per common share:				
Weighted average shares of common stock outstanding (in thousands)	485,675	485,732	485,560	485,002
Net income (loss) per common share attributable to Calpine – diluted	$ (0.16)	$ 0.41	$ (0.09)	$ (0.04)

The accompanying notes are an integral part of these
Consolidated Condensed Financial Statements.

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED CONDENSED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30, 2009	Six Months Ended June 30, 2008
	(in millions)	
Cash flows from operating activities:		
Net loss	$ (48)	$ (17)
Adjustments to reconcile net loss to net cash used in operating activities:		
Depreciation and amortization expense (1)	268	280
Debt extinguishment costs	7	7
Deferred income taxes	26	85
Loss on disposal of assets, excluding reorganization items	20	6
Mark-to-market activity, net	(23)	63
Income from unconsolidated investments in power plants	(40)	(13)
Stock-based compensation expense	22	19
Reorganization items	—	(322)
Other	1	—
Change in operating assets and liabilities:		
Accounts receivable	29	(246)
Derivative instruments	(257)	(255)
Other assets	173	(246)
Accounts payable, LSTC and accrued expenses	(23)	382
Other liabilities	(191)	(329)
Net cash used in operating activities	(36)	(586)
Cash flows from investing activities:		
Purchases of property, plant and equipment	(97)	(79)
Disposals of property, plant and equipment	—	11
Proceeds from sale of power plants, turbines and investments	—	398
Cash acquired due to reconsolidation of Canadian Debtors and other foreign entities	—	64
Contributions to unconsolidated investments	(8)	(9)
Return of investment from unconsolidated investment	—	24
(Increase) decrease in restricted cash	(31)	56
Other	(1)	4
Net cash provided by (used in) investing activities	(137)	469
Cash flows from financing activities:		
Repayments of notes payable	(54)	(49)
Repayments of project financing	(843)	(229)
Borrowings from project financing	1,027	356
Repayments of DIP Facility	—	(113)
Borrowings under Exit Facilities	—	3,473
Repayments on Exit Facilities	(30)	(855)
Repayments on Second Priority Debt	—	(3,672)
Repayments on capital leases	(31)	(26)
Redemptions of preferred interests	(41)	(159)
Financing costs	(29)	(187)
Derivative contracts classified as financing activities	—	34
Other	(1)	(1)
Net cash used in financing activities	(2)	(1,428)
Net decrease in cash and cash equivalents	(175)	(1,545)
Cash and cash equivalents, beginning of period	1,657	1,915
Cash and cash equivalents, end of period	$ 1,482	$ 370

The accompanying notes are an integral part of these
Consolidated Condensed Financial Statements.

CONSOLIDATED CONDENSED STATEMENTS OF CASH FLOWS – (Continued)
(Unaudited)

	Six Months Ended June 30,	
	2009	2008
Cash paid (received) during the period for:		
Interest, net of amounts capitalized	$ 398	$ 634
Income taxes	$ 2	$ 15
Reorganization items included in operating activities, net	$ 6	$ 109
Reorganization items included in investing activities, net	$ —	$ (414)
Supplemental disclosure of non-cash investing and financing activities:		
Settlement of commodity contract with project financing	$ 79	$ —
Change in capital expenditures included in accounts payable	$ —	$ (6)
Settlement of LSTC through issuance of reorganized Calpine Corporation common stock	$ —	$ 5,200
DIP Facility borrowings converted into exit financing under the Exit Facilities	$ —	$ 3,872
Settlement of Convertible Senior Notes and Unsecured Senior Notes with reorganized Calpine Corporation common stock	$ —	$ 3,703

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(1) Includes depreciation and amortization that is also recorded in sales, general and other administrative expense and interest expense on our Consolidated Condensed Statements of Operations.

The accompanying notes are an integral part of these
Consolidated Condensed Financial Statements.

CALPINE CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED CONDENSED FINANCIAL STATEMENTS
June 30, 2009
(**Unaudited**)

1. Basis of Presentation and Summary of Significant Accounting Policies

We are an independent wholesale power generation company engaged in the ownership and operation of natural gas-fired and geothermal power plants in North America. We have a significant presence in the major competitive power markets in the U.S., including California and Texas. We sell wholesale power, steam, capacity, renewable energy credits and ancillary services to our customers, including industrial companies, retail power providers, utilities, municipalities, independent electric system operators, marketers and others. We engage in the purchase of natural gas as fuel for our power plants and in related natural gas transportation and storage transactions, and in the purchase of electric transmission rights to deliver power to our customers. We also enter into natural gas and power, commodity and financial derivative transactions to economically hedge our business risks and optimize our portfolio of power plants.

Basis of Interim Presentation — The accompanying unaudited interim Consolidated Condensed Financial Statements of Calpine Corporation, a Delaware corporation, and consolidated subsidiaries have been prepared pursuant to the rules and regulations of the SEC. In the opinion of management, the Consolidated Condensed Financial Statements include the adjustments necessary for a fair statement of the information required to be set forth therein. Certain information and note disclosures normally included in financial statements prepared in accordance with GAAP 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 our audited Consolidated Financial Statements for the year ended December 31, 2008, included in our 2008 Form 10-K. The results for interim periods are not necessarily indicative of the results for the entire year primarily due to seasonal fluctuations in our revenues, major maintenance expenses and volatility of commodity prices.

During the period January 1, 2008, through January 31, 2008, we conducted our business in the ordinary course as debtors-in-possession under the protection of the Bankruptcy Courts. We emerged from Chapter 11 on January 31, 2008. In accordance with Financial Reporting by Entities in Reorganization under the Bankruptcy Code prescribed by GAAP, certain income, expenses, realized gains and losses and provisions for losses that were realized or incurred in our Chapter 11 cases are recorded in reorganization items on our Consolidated Condensed Statements of Operations. See Note 11 for further discussion of our Plan of Reorganization.

Canadian Subsidiaries — As a result of filings by the Canadian Debtors under the CCAA in the Canadian Court, we deconsolidated most of our Canadian Debtors and other foreign entities as of December 20, 2005, the Petition Date, as we determined that the administration of the CCAA proceedings in a jurisdiction other than that of the U.S. Debtors' Chapter 11 cases resulted in a loss of the elements of control necessary for consolidation and we fully impaired our investment in our Canadian Debtors and other foreign entities. On February 8, 2008, the Canadian Effective Date, the Canadian Court ordered and declared that the CCAA proceedings were terminated. The termination of the proceedings of the CCAA and our emergence under the Plan of Reorganization allowed us to maintain our equity interest in the Canadian Debtors and other foreign entities, whose principal assets include various working capital items and a 50% ownership interest in Whitby, an equity method investment. As a result, we regained control over our Canadian Debtors and other foreign entities which were reconsolidated into our Consolidated Condensed Financial Statements as of the Canadian Effective Date.

We accounted for the reconsolidation under the purchase method in a manner similar to a step acquisition. The excess of the fair market value of the reconsolidated net assets over the carrying value of our investment balance of $0 amounted to approximately $133 million. We recorded the Canadian assets acquired and the liabilities assumed based on their estimated fair value, with the exception of Whitby. We reduced the fair value of our Whitby equity investment (approximately $62 million) to $0 on the Canadian Effective Date and recorded the $71 million balance of the excess as a gain in reorganization items on our 2008 Consolidated Statement of Operations.

Equity Method Investments — We use the equity method of accounting to record our net interest in OMEC, a VIE where we have determined that we are not the primary beneficiary, Greenfield LP, a joint venture interest and Whitby, a less-than-majority-owned company in which we exercise significant influence over operating and financial policies. Our share of net income (loss) is calculated according to our equity ownership or according to the terms of the applicable partnership agreement. See Note 3 for further discussion of our VIEs and unconsolidated investments.

Reclassifications — Certain reclassifications have been made to our December 31, 2008 Consolidated Condensed Balance Sheet, our Consolidated Condensed Statements of Operations for the three and six months ended June 30, 2008, and our Consolidated Condensed Statement of Cash Flows for the six months ended June 30, 2008, to conform to the current period presentation. Our reclassifications are summarized as follows:

- We adopted the new accounting requirements under GAAP for noncontrolling interests in consolidated financial statements effective January 1, 2009, and accordingly have reclassified minority interest as "noncontrolling interest," a component of Stockholders' Equity, on our Consolidated Condensed Balance Sheets and included "net loss attributable to the noncontrolling interest" as a separate component on our Consolidated Condensed Statements of Operations. See "New Accounting Requirements and Disclosures" for a further discussion regarding this requirement.
- Our (income) loss from unconsolidated investments in power plants was previously included within other operating expense, but is now included as a separate line item on our Consolidated Condensed Statements of Operations.
- We have reclassified certain amounts within our cash flows used in operating activities on our Consolidated Condensed Statement of Cash Flows for the six months ended June 30, 2008, to separately state non-cash debt extinguishment costs previously reflected in changes in other assets and unrealized mark-to-market activity previously reflected in our changes in derivative instruments, in order to conform to our current period presentation.

Use of Estimates in Preparation of Financial Statements — The preparation of financial statements in conformity with GAAP requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and related disclosures included in the Consolidated Condensed Financial Statements. Actual results could differ from those estimates.

Fair Value of Financial Instruments — The carrying values of accounts receivable, accounts payable and other receivables and payables approximate their respective fair values due to their short-term maturities. See Note 6 for disclosures regarding the fair value of our debt instruments.

Concentrations of Credit Risk — Financial instruments that potentially subject us to credit risk consist of cash and cash equivalents, restricted cash, accounts receivable and derivative assets. Certain of our cash and cash equivalents as well as our restricted cash balances exceed FDIC insured limits or are invested in money market accounts with investment banks that are not FDIC insured. We place our cash and cash equivalents and restricted cash in what we believe to be credit-worthy financial institutions and certain of our money market accounts invest in U.S. Treasury securities or other obligations issued or guaranteed by the U.S. government or its agencies. Additionally, we actively monitor the credit risk of our receivable and derivative counterparties. Our accounts and notes receivable are concentrated within entities engaged in the energy industry, mainly within the U.S. We generally have not collected collateral for accounts receivable from utilities and end-user customers; however, we may require collateral in the future. For financial and commodity counterparties, we evaluate the net accounts receivable, accounts payable and fair value of commodity contracts and may require security deposits, cash margin or letters of credit to be posted if our exposure reaches a certain level.

Cash and Cash Equivalents — We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents. We have certain project finance facilities and lease agreements that establish segregated cash accounts which have been pledged as security in favor of the lenders under such project finance facilities, and the use of certain cash balances on deposit in such accounts is limited, at least temporarily, to the operations of the respective projects. At June 30, 2009, and December 31, 2008, we had cash and cash equivalents of $454 million and $296 million, respectively, that were subject to such project finance facilities and lease agreements.

Restricted Cash — We are required to maintain cash balances that are restricted by provisions of certain of our debt and lease agreements or other operating agreements. These amounts are held by depository banks in order to comply with the contractual provisions requiring reserves for payments such as for debt service, rent, major maintenance and debt repurchases or with applicable regulatory requirements. Funds that can be used to satisfy obligations due during the next 12 months are classified as current restricted cash, with the remainder classified as non-current restricted cash. Restricted cash is generally invested in accounts earning market rates; therefore, the carrying value approximates fair value. Such cash is excluded from cash and cash equivalents in the Consolidated Condensed Balance Sheets and Statements of Cash Flows.

The table below represents the components of our restricted cash as of June 30, 2009, and December 31, 2008 (in millions):

	June 30, 2009			December 31, 2008		
	Current	Non-Current	Total	Current	Non-Current	Total
Debt service	$ 202	$ 25	$ 227	$ 102	$ 121	$ 223
Rent reserve	17	—	17	34	—	34
Construction/major maintenance	76	16	92	72	18	90
Security/project	103	1	104	96	1	97
Collateralized letters of credit and other credit support	51	—	51	7	1	8
Other	35	8	43	26	25	51
Total	$ 484	$ 50	$ 534	$ 337	$ 166	$ 503

Income Taxes — As of June 30, 2009, our federal income tax reporting group is comprised primarily of two groups, CCFC and its subsidiaries, which we refer to as the CCFC group, and Calpine Corporation and its subsidiaries other than CCFC, which we refer to as the Calpine group. This is due to the issuance of the CCFCP Preferred Shares in 2005, which resulted in the deconsolidation of the CCFC group for income tax purposes. As of June 30, 2009, the CCFC group does not have a valuation allowance recorded against its deferred tax assets, whereas the Calpine group continues to have a valuation allowance. For the three and six months ended June 30, 2009, we used the effective rate method to determine both our CCFC and Calpine groups' tax provision; however, our income tax rates did not bear a customary relationship to statutory income tax rates as a result of the impact of state income taxes, changes in unrecognized tax benefits, the Calpine group valuation allowance, and intraperiod tax allocations as discussed below. For the three and six months ended June 30, 2008, we determined that the effective rate method for computing the Calpine group tax provision did not provide meaningful results because of the uncertainty in reliably estimating our 2008 annual effective tax rate. As a result, we calculated our tax provision for the three and six months ended June 30, 2008, based on an actual, or discrete, method. Under this method, we determined the Calpine group tax expense based upon actual results as if the interim period were an annual period. For the three and six months ended June 30, 2008, the CCFC group utilized the effective rate method to determine its income tax expense. Under both of these methods, our imputed tax rate was (23)% and 11% for the three months ended June 30, 2009 and 2008, respectively, and (100)% and 667% for the six months ended June 30, 2009 and 2008, respectively. Our consolidated income tax expense was $15 million and $25 million for the three months ended June 30, 2009 and 2008, respectively, and $24 million and $20 million for the six months ended June 30, 2009 and 2008, respectively. In accordance with intraperiod tax allocation provisions, our income tax expense (benefit) included $14 million and $(2) million for the three months ended June 30, 2009 and 2008, respectively, and $27 million and $(2) million for the six months ended June 30, 2009 and 2008, respectively, on our Consolidated Condensed Statements of Operations, with an offsetting tax benefit to OCI.

GAAP requires that we consider all available evidence, both positive and negative, and tax planning strategies to determine whether, based on the weight of that evidence, a valuation allowance is needed. Future realization of the tax benefit of an existing deductible temporary difference or carryforward ultimately depends on the existence of sufficient taxable income of the appropriate character within the carryback or carryforward periods available under the tax law. We have provided a valuation allowance on certain federal, state and foreign tax jurisdiction deferred tax assets of the Calpine group to reduce the gross amount of these assets to the extent necessary to result in an amount that is more likely than not of being realized. Projected future income from reversals of existing taxable temporary differences and tax planning strategies allowed a larger portion of the deferred tax assets to be offset against deferred tax liabilities resulting in a significant release of previously recorded valuation allowance.

As of June 30, 2009, we had unrecognized tax benefits of $97 million. If recognized, $48 million of our unrecognized tax benefits could impact the annual effective tax rate and $49 million related to deferred tax assets could be offset against the recorded valuation allowance within the next 12 months. We also had accrued interest and penalties of $18 million for income tax matters as of June 30, 2009, and if recognized, could also impact the annual effective tax rate. The amount of unrecognized tax benefits increased by $7 million for the six months ended June 30, 2009, primarily as a result of an increase of approximately $9 million for withholding taxes and reductions of approximately $2 million due to settlements with various state taxing authorities. We believe it is reasonably possible that a decrease of up to $6 million in unrecognized tax benefits could occur within the next 12 months primarily related to penalties and interest for federal and foreign tax filings as well as state tax liabilities as a result of settlements with the tax authorities.

Under federal income tax law, our NOL carryforwards can be utilized to reduce future taxable income subject to certain limitations, including if we were to undergo an ownership change as defined by the IRC. We experienced an ownership change on the Effective Date as a result of the cancellation of our old common stock and the distribution of our new common stock pursuant to the Plan of Reorganization. However, this ownership change and resulting annual limitations are not expected to result in the expiration of our NOL carryforwards if we are able to generate sufficient future taxable income within the carryforward periods. If a subsequent ownership change were to occur as a result of future transactions in our stock, accompanied by a significant reduction in our market value immediately prior to the ownership change, our ability to utilize the NOL carryforwards may be significantly limited.

To prevent the risk of loss of our ability to utilize our tax NOL carryforwards, our amended and restated certificate of incorporation permits our Board of Directors to meet to determine whether to impose certain transfer restrictions on our common stock in the following circumstances: if, prior to February 1, 2013, our Market Capitalization declines by at least 35% from our Emergence Date Market Capitalization of approximately $8.6 billion (in each case, as defined in and calculated pursuant to our amended and restated certificate of incorporation) and at least 25 percentage points of shift in ownership has occurred with respect to our equity for purposes of Section 382 of the IRC. As of the filing of this Report, our Market Capitalization decline threshold exceeds the 35% limit discussed above; however, our shift in ownership is approximately 15% and both circumstances are not met. Accordingly, the transfer restrictions are not currently operative but could become operative in the future if both of the foregoing events were to occur together and our Board of Directors were to elect to impose them. There can be no assurance that the circumstances will not be met in the future, or in the event that they are met, that our Board of Directors would choose to impose these restrictions or that, if imposed, such restrictions would prevent an ownership change from occurring.

We have filed a registration statement on Form S-3 registering the resale of the common stock held by two groups of related holders of our common stock that collectively owned approximately 42% of our common stock at June 30, 2009, which permits them to sell a large portion of their shares of common stock without being subject to the “trickle out” or other restrictions of Rule 144 under the Securities Act. If these shareholders sought to sell all of their remaining registered shares within a short period of time, pursuant to the Form S-3 or otherwise, it would result in a shift in ownership of greater than 25 percentage points and our Board of Directors could elect to impose certain trading restrictions on our common stock as described above.

We remain subject to various audits and reviews by state taxing authorities; however, we do not expect these will have a material effect on our tax provision. Any NOLs we claim in future years to reduce taxable income could be subject to IRS examination regardless of when the NOLs occurred. Due to significant NOLs, any adjustment of state returns or federal returns from 2007 and forward would likely result in a reduction of deferred tax assets rather than a cash payment of income taxes.

New Accounting Requirements and Disclosures

Accounting Standards Codification and GAAP Hierarchy — In June 2009, FASB issued SFAS No. 168, “The FASB Accounting Standards Codification and the Hierarchy of Generally Accepted Accounting Principles,” which supersedes SFAS No. 162, “The Hierarchy of Generally Accepted Accounting Principles” and makes the ASC the single official source of authoritative, nongovernmental GAAP. FASB’s purpose in implementing the ASC is to simplify GAAP, without change, by consolidating the numerous accounting rules into logically organized topics. All other literature not included in the ASC will be considered non-authoritative. For ease of reference by public companies, the ASC also includes relevant authoritative content issued by the SEC, as well as selected SEC Staff interpretations and administrative guidance. The ASC will be effective for all interim and annual periods ending after September 15, 2009, and will not have any impact on our future results of operations, financial condition or cash flows as it does not represent new accounting literature or requirements; however, it will change our references to authoritative GAAP sources for our accounting policies, presentation and disclosures in future filings.

Fair Value Measurements — In September 2006, FASB issued SFAS No. 157, “Fair Value Measurements,” which became effective for fiscal years beginning after November 15, 2007, and for interim periods within those years. SFAS No. 157 defines fair value, establishes a framework for measuring fair value under GAAP, and enhances disclosures about fair value measurements. SFAS No. 157 applies when other accounting pronouncements require fair value measurements; it does not require any new fair value measurements. We adopted SFAS No. 157 on January 1, 2008, for financial assets and liabilities that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually). In February 2008, the effective date of SFAS No. 157, was deferred for non-financial assets and liabilities until fiscal years and interim periods beginning after November 15, 2008. Accordingly, we adopted SFAS No. 157 as of January 1, 2009, with respect to non-financial assets and non-financial liabilities, which did not have a material effect on our results of operations, financial position or cash flows; however, adoption may impact measurements of asset impairments and asset retirement obligations if they occur in the future.

Determining Fair Value in Inactive Markets — In April 2009, FASB issued FSP No. FAS 157-4, "Determining Fair Value When the Volume and Level of Activity for the Asset or Liability Have Significantly Decreased and Identifying Transactions That Are Not Orderly," which applies to all fair value measurements when appropriate. Among other things, FSP No. FAS 157-4:

- affirms that the objective of fair value, when the market for an asset is not active, is the price that would be received in a sale of the asset in an orderly transaction;
- clarifies certain factors and includes additional factors for determining whether there has been a significant decrease in market activity for an asset when the market for that asset is not active;
- provides that a transaction for an asset or liability may not be presumed to be distressed (not orderly) simply because there has been a significant decrease in the volume and level of activity for the asset or liability, rather, a company must determine whether a transaction is not orderly based on the weight of the evidence, and includes a non-exclusive list of the evidence that may indicate that a transaction is not orderly; and
- requires disclosure in interim and annual periods of the inputs and valuation techniques used to measure fair value and any change in valuation technique (and the related inputs) resulting from the application of the FSP, including quantification of its effects, if practicable.

FSP No. FAS 157-4 must be applied prospectively and retrospective application is not permitted. FSP No. FAS 157-4 is effective for interim and annual periods ending after June 15, 2009. We adopted this standard as of June 30, 2009. Adoption of this standard resulted in a clarification of existing accounting guidance with no change to our accounting policies and had no effect on our results of operations, cash flows or financial position. See Note 7 for disclosure of our fair value measurements.

Interim Disclosures About Fair Value of Financial Instruments — In April 2009, FASB issued FSP No. FAS 107-1 and APB 28-1, "Interim Disclosures about Fair Value of Financial Instruments." FSP No. FAS 107-1 and APB 28-1 amends FASB Statement No. 107, "Disclosures about Fair Value of Financial Instruments," as well as APB Opinion No. 28, "Interim Financial Reporting," to require disclosures about fair value of financial instruments in interim financial statements as well as in annual financial statements. FSP No. FAS 107-1 and APB 28-1 is effective for interim and annual periods ending after June 15, 2009, with early adoption permitted for periods ending after March 15, 2009. We adopted this standard as of June 30, 2009. Adoption of this standard resulted in the addition of interim disclosures of the fair values of our financial instruments, which previously had only been required annually. Adoption of this standard resulted in no change to our accounting policies and had no effect on our results of operations, cash flows or financial position. See Note 6 for disclosure of the fair value of our debt.

Business Combinations — In December 2007, FASB issued SFAS No. 141(R), "Business Combinations," which replaces SFAS No. 141 and establishes principles and requirements for how the acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree. In addition, SFAS No. 141(R) recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase. SFAS No. 141(R) also establishes disclosure requirements to enable users to evaluate the nature and financial effects of the business combination. In April 2009, FASB issued FSP No. FAS 141(R)-1, "Accounting for Assets Acquired and Liabilities Assumed in a Business Combination That Arises from Contingencies," which amends and clarifies SFAS No. 141(R) on initial recognition and measurement, subsequent measurement and accounting, and disclosure of assets and liabilities arising from contingencies in a business combination. SFAS No. 141(R) and FSP No. FAS 141(R)-1 are effective as of the beginning of an entity's fiscal year that begins after December 15, 2008, with early adoption prohibited. We adopted SFAS No. 141(R) and FSP No. FAS 141(R)-1 effective January 1, 2009. Adoption of these standards did not have a material effect on our results of operations, cash flows or financial position.

Noncontrolling Interests in Consolidated Financial Statements — In December 2007, FASB issued SFAS No. 160, "Noncontrolling Interests in Consolidated Financial Statements – An Amendment of ARB No. 51." SFAS No. 160 establishes accounting and reporting standards for ownership interests in subsidiaries held by parties other than the parent, the amount of consolidated net income attributable to the parent and to the noncontrolling interest, and changes in a parent's ownership interest while the parent retains its controlling financial interest in its subsidiary. In addition, SFAS No. 160 establishes principles for valuation of retained noncontrolling equity investments and measurement of gain or loss when a subsidiary is deconsolidated. SFAS No. 160 also establishes disclosure requirements to clearly identify and distinguish between interests of the parent and the interests of the noncontrolling owners. SFAS No. 160 is effective for fiscal years and interim periods beginning after December 15, 2008, with early adoption prohibited. We adopted SFAS No. 160 as of January 1, 2009, which did not have a material impact on our results of operations, financial position or cash flows; however, adoption did result in the reclassification of minority interest to noncontrolling interest on our Consolidated Condensed Balance Sheets and Statements of Operations.

Disclosures About Derivative Instruments and Hedging Activities — In March 2008, FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities – An Amendment of FASB Statement No. 133." SFAS No. 161 requires enhanced disclosures about an entity's derivative and hedging activities to enable investors to better understand their effects on the entity's financial position, financial performance, and cash flows. SFAS No. 161 is effective for fiscal years and interim periods beginning after November 15, 2008, with early adoption encouraged. We adopted SFAS No. 161 as of January 1, 2009. Adoption of this standard resulted in additional disclosures related to our derivatives and hedging activities including additional disclosures regarding our objectives for entering into derivative transactions, increased balance sheet and financial performance disclosures, volume information and credit enhancement disclosures. See Note 8 for our derivative disclosures.

Disclosures About Credit Derivatives and Certain Guarantees — In September 2008, FASB issued FSP No. FAS 133-1 and FIN 45-4, "Disclosures about Credit Derivatives and Certain Guarantees: An Amendment of FASB Statement No. 133 and FASB Interpretation No. 45; and Clarification of the Effective Date of FASB Statement No. 161." This FSP requires enhanced disclosures for credit derivatives and certain guarantees about the potential adverse effects of changes in credit risk, financial position, financial performance and cash flows of an entity selling credit derivatives. FSP No. FAS 133-1 and FIN 45-4 is effective for fiscal years and interim periods beginning after November 15, 2008, with early adoption encouraged. FSP No. FAS 133-1 and FIN 45-4 requires enhanced disclosures specific to credit derivatives and certain guarantees. We adopted FSP No. FAS 133-1 and FIN 45-4 as of January 1, 2009. Currently, we do not have instruments that meet the requirements for additional disclosure, and adoption of this standard did not have any impact on our results of operations, cash flows or financial position.

Subsequent Events — In May 2009, FASB issued SFAS No. 165, "Subsequent Events," which establishes general standards of accounting for and disclosure of events that occur after the balance sheet date but before financial statements are issued or are available to be issued. This standard is effective for interim and annual financial periods ending after June 15, 2009, and shall be applied prospectively. This standard does not change the accounting for subsequent events; but does require disclosure of the date an entity has evaluated subsequent events. We adopted SFAS No. 165 effective for the three and six month periods ended June 30, 2009, which had no impact on our results of operations, financial condition or cash flows. We have evaluated subsequent events through July 30, 2009.

Consolidation of Variable Interest Entities — In June 2009, FASB issued SFAS No. 167, an amendment of FIN 46(R), "Consolidation of Variable Interest Entities." SFAS No. 167 amends FIN 46(R) to replace standards for determining which enterprise has a controlling financial interest in a VIE and amends guidance in FIN 46(R) for determining whether an entity is a VIE. This statement also adds reconsideration events for determining whether an entity is a VIE and requires ongoing reassessment of which entity is determined to be the VIE's primary beneficiary. In addition, SFAS No. 167 requires enhanced disclosures about the enterprise's involvement in a VIE and nullifies FSP 140-4 and FIN 46(R)-8, "Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interests in Variable Interest Entities." SFAS No. 167 is effective for interim and annual periods beginning after November 15, 2009, with earlier application prohibited. We are currently assessing the future impact this statement will have on our results of operations, financial position or cash flows. See Note 3 for a discussion of our VIEs.

2. Property, Plant and Equipment, Net

As of June 30, 2009, and December 31, 2008, the components of property, plant and equipment are stated at cost less accumulated depreciation as follows (in millions):

	June 30, 2009	December 31, 2008
Buildings, machinery and equipment	$ 13,370	$ 13,360
Geothermal properties	1,018	979
Other	257	258
	14,645	14,597
Less: Accumulated depreciation	(3,134)	(2,932)
	11,511	11,665
Land	76	76
Construction in progress	173	167
Property, plant and equipment, net	$ 11,760	$ 11,908

We are in the process of reviewing our accounting policies related to depreciation including our estimates of useful lives to determine if other depreciation methods allowed under GAAP may be preferable (i.e. changing certain assets from composite depreciation to component depreciation). If, as a result of our review and upon the completion of a depreciable life study currently underway, we determine that another depreciation method is preferred under GAAP, we may change our accounting policies to the more preferred method as appropriate and anticipate that we would account for any such change on a prospective basis as a change in estimate in accordance with GAAP. At this time, we are unable to determine if a change to another GAAP depreciation method is preferred and, if preferred, the impact these changes could have on our future financial statements. However, such changes, if any, could be material.

3. Variable Interest Entities and Unconsolidated Investments

We consolidate all VIEs where we are the primary beneficiary. This determination is made at the inception of our involvement with the VIE and, in accordance with GAAP, is updated only in response to a reconsideration event. Beginning on January 1, 2010, new accounting requirements will require us to perform an ongoing reassessment of whether we continue to be the primary beneficiary. We consider both qualitative and quantitative factors to form a conclusion as to whether we, or another interest holder, absorbs a majority of the entity's risk of expected losses, receives a majority of the entity's potential for expected residual returns, or both. Our consolidated VIEs are aggregated into the following classifications in order of priority:

- *Consolidated VIEs with a Purchase Option* — Certain of our subsidiaries have PPAs or other agreements that provide third parties the option to purchase power plant assets, an equity interest, or a portion of the future cash flows generated from an asset. For these VIEs, we determined at the time we entered into the contractual arrangement that consolidation was appropriate because exercise of the option was considered unlikely or would not provide the majority of the risk or reward from the project.

- *Consolidated Subsidiaries with Project Debt* — Certain of our subsidiaries have project debt that contains provisions which we have determined create variability. We retain ownership and absorb the full risk of loss and potential for reward once the project debt is paid in full. Actions by the lender to assume control of collateral can occur only under limited circumstances such as upon the occurrence of an event of default, which we have determined to be unlikely. Accordingly, we are the primary beneficiary of these VIEs. See Note 6 for further information regarding our project debt and Note 1 for information regarding our restricted cash balances.

- *Consolidated Subsidiaries with PPAs* — Certain of our 100% owned subsidiaries have PPAs that are deemed to be a form of subordinated financial support and thus constitute a VIE. For all such VIEs we have determined that we are the primary beneficiary as we retain the primary risk of loss over the life of the project.

- *Other Consolidated VIEs* — Our other consolidated VIEs primarily consist of monetized assets secured by financing. For each of these arrangements we are the primary beneficiary as we retain both the primary risk of loss and potential for reward associated with the assets of the subsidiary.

The table below details the assets and liabilities (excluding intercompany balances which are eliminated in consolidation) for our VIEs, combined by VIE classification, that are included in our Consolidated Condensed Balance Sheets as of June 30, 2009, and December 31, 2008 (in millions):

Condensed Combined VIE Assets and Liabilities

	June 30, 2009			
	Purchase Options	Project Debt	PPAs	Other
Assets:				
Current assets	$ 263	$ 542	$ 108	$ 209
Restricted cash, net of current portion	11	13	17	—
Property, plant and equipment, net	2,622	3,129	1,322	—
Other assets	82	62	13	—
Total assets(1)	$ 2,978	$ 3,746	$ 1,460	$ 209
Liabilities:				
Current liabilities	$ 133	$ 361	$ 33	$ 223
Long-term debt	1,132	1,958	9	—
Long-term derivative liabilities	7	6	—	—
Other liabilities	10	11	9	—
Total liabilities(1)	$ 1,282	$ 2,336	$ 51	$ 223

	December 31, 2008			
	Purchase Options	Project Debt	PPAs	Other
Assets:				
Current assets	$ 224	$ 369	$ 152	$ 103
Restricted cash, net of current portion	3	16	27	111
Property, plant and equipment, net	2,863	2,438	1,413	—
Other assets	94	32	7	4
Total assets(1)	$ 3,184	$ 2,855	$ 1,599	$ 218
Liabilities:				
Current liabilities	$ 204	$ 412	$ 33	$ 142
Long-term debt	1,413	1,313	58	131
Long-term derivative liabilities	11	14	—	—
Other liabilities	10	5	9	—
Total liabilities(1)	$ 1,638	$ 1,744	$ 100	$ 273

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(1) The assets and liabilities listed above for our VIEs with purchase options may not be indicative of our risk of loss. Some of the assets and liabilities above include VIEs where the sale options are held by us, some are for only a minority interest, some are effective only upon the occurrence of an event of default and some are only for a portion of a VIE’s total assets and liabilities.

Unconsolidated VIEs and Investments

We do not consolidate OMEC, a VIE where we have determined that we are not the primary beneficiary. We also have a joint venture interest in Greenfield LP and a less-than-majority equity interest in Whitby where we do not have control and therefore do not consolidate. We account for these entities under the equity method of accounting and include our net equity interest in investments on our Consolidated Condensed Balance Sheets as we exercise significant influence over operating and financial policies. Our equity interest in the net income from our unconsolidated VIE, joint venture and equity interest is recorded in income from unconsolidated investments in power plants on a net basis.

At June 30, 2009, and December 31, 2008, our equity method investments included on our Consolidated Condensed Balance Sheets were comprised of the following (in millions):

	Ownership Interest as of June 30, 2009	June 30, 2009	December 31, 2008
OMEC	100%	$ 135	$ 98
Greenfield LP	50%	67	46
Whitby	50%	2	—
Total investments		$ 204	$ 144

OMEC — OMEC, an indirect wholly owned subsidiary, is the owner of the Otay Mesa Energy Center, a 596 MW natural gas-fired power plant currently under construction in southern San Diego County, California. OMEC has a ten-year tolling agreement with SDG&E. We do not consolidate OMEC as a result of a put option held by OMEC to sell the Otay Mesa Energy Center for $280 million to SDG&E, and a call option held by SDG&E to buy the Otay Mesa Energy Center for $377 million at the end of the agreement. We determined SDG&E has a greater variability of risk compared to us and we are not the primary beneficiary.

OMEC has a $377 million non-recourse project finance facility structured as a construction loan, which converts to a term loan upon commercial operation of Otay Mesa Energy Center, and matures in April 2019. Borrowings under the project finance facility are initially priced at LIBOR plus 1.5%. We contributed $4 million and $8 million during the three and six months ended June 30, 2009, respectively, and $9 million for both the three and six months ended June 30, 2008, as an additional investment in OMEC.

Greenfield LP — Greenfield LP is a limited partnership between certain subsidiaries of ours and of Mitsui & Co., Ltd., which operates the Greenfield Energy Centre, a 1,005 MW natural gas-fired power plant in Ontario, Canada. We and Mitsui & Co., Ltd. each hold a 50% interest in Greenfield LP. Greenfield LP holds an 18-year term loan in the amount of Can$648 million. Borrowings under the project finance facility are initially priced at Canadian LIBOR plus 1.2% or Canadian prime rate plus 0.2%.

Whitby — Represents our 50% investment in Whitby held by our Canadian subsidiaries, which were reconsolidated on the Canadian Effective Date.

RockGen — During the first quarter of 2008, we deconsolidated RockGen and subsequently reconsolidated RockGen in December 2008.

The following details our (income) loss and distributions from unconsolidated investments in power plants for the three and six months ended June 30, 2009 and 2008 (in millions):

	Three Months Ended June 30,			
	2009	2008	2009	2008
	(Income) Loss from Unconsolidated Investments in Power Plants		Distributions	
OMEC	$ (16)	$ (15)	$ —	$ —
Greenfield LP	(5)	2	—	—
RockGen	—	(1)	—	—
Whitby	(2)	(2)	—	—
Total	$ (23)	$ (16)	$ —	$ —

	Six Months Ended June 30,			
	2009	2008	2009	2008
	(Income) Loss from Unconsolidated Investments in Power Plants		Distributions	
OMEC	$ (26)	$ (15)	$ —	$ —
Greenfield LP	(10)	8	—	24
RockGen	—	(4)	—	—
Whitby	(4)	(2)	2	—
Total	$ (40)	$ (13)	$ 2	$ 24

Our risk of loss related to our unconsolidated VIEs is limited to our investment balance and our construction cost and operational risk related to OMEC. The debt on the books of our unconsolidated investments is not reflected on our Consolidated Condensed Balance Sheets. As of June 30, 2009, and December 31, 2008, equity method investee debt was approximately $777 million and $697 million, respectively. Based on our pro rata share of each of the investments, our share of such debt would be approximately $547 million and $477 million as of June 30, 2009, and December 31, 2008, respectively. All such debt is non-recourse to us.

Inland Empire Energy Center Put and Call Options — We hold a call option to purchase the Inland Empire Energy Center development project (a 775 MW natural gas-fired power plant located in California) from GE that may be exercised between years 7 and 14 of the life of the power plant. GE holds a put option whereby they can require us to purchase the power plant, if certain plant performance criteria are met during year 15 of the life of the power plant. We determined that we were not the primary beneficiary of the Inland Empire power plant as we do not absorb the majority of the risk of loss associated with the project due to factors including, but not limited to, the fact that GE will manage and fully fund the construction of the power plant, as well as manage and operate the power plant after the power plant reaches commercial operations. Additionally, if we purchase the power plant under the call or put options, GE will continue to provide critical plant maintenance services throughout the remaining estimated useful life of the power plant.

Significant Subsidiary — OMEC and Greenfield LP meet the criteria of a significant subsidiary as defined under SEC guidelines, based upon the relationship of our equity income from our investment in these subsidiaries to our consolidated net income before income taxes. The Condensed Statements of Operations for OMEC and Greenfield LP for the three and six months ended June 30, 2009 and 2008, are set forth below (in millions):

OMEC
Condensed Statements of Operations

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Revenues	$ —	$ —	$ —	$ —
Operating expenses	1	—	2	—
Loss from operations	(1)	—	(2)	—
Interest income(1)	(22)	(15)	(33)	(15)
Other (income) expense, net	5	—	5	—
Net income	$ 16	$ 15	$ 26	$ 15

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(1) Interest income is the result of unrealized mark-to-market gains from an interest rate swap contract.

Greenfield LP
Condensed Statements of Operations

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008[(1)]	2009	2008[(1)]
Revenues	$ 43	$ —	$ 103	$ —
Operating expenses	28	3	73	3
Income (loss) from operations	15	(3)	30	(3)
Interest (income) expense	7	(1)	11	(1)
Other (income) expense, net	(2)	(1)	(1)	1
Net income (loss)	$ 10	$ (1)	$ 20	$ (3)

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(1) Greenfield LP began commercial operations on October 17, 2008.

4. Asset Sales

On February 14, 2008, we completed the sale of substantially all of the assets comprising the Hillabee development project, a partially completed 774 MW combined-cycle power plant located in Alexander City, Alabama, to CER Generation, LLC for approximately $156 million, plus the assumption by CER Generation LLC of certain liabilities. We recorded a pre-tax gain of approximately $63 million in reorganization items on our Consolidated Condensed Statement of Operations for the six months ended June 30, 2008.

On March 5, 2008, we completed the sale of substantially all of the assets comprising the Fremont development project, a partially completed 550 MW natural gas-fired power plant located in Fremont, Ohio, to First Energy Generation Corp. for approximately $254 million, plus the assumption by First Energy Generation Corp. of certain liabilities. We recorded a pre-tax gain of approximately $136 million in reorganization items on our Consolidated Condensed Statement of Operations for the six months ended June 30, 2008.

The sales of the Hillabee and Fremont development projects did not meet the criteria for discontinued operations due to our continuing activity in the markets in which these power plants were located; therefore, the results of operations for all periods prior to sale are included in our continuing operations.

5. Comprehensive Income (Loss)

Comprehensive income (loss) includes our net income (loss), unrealized gains and losses from derivative instruments, net of tax that qualify as cash flow hedges, our share of equity method investees' OCI and the effects of foreign currency translation adjustments. We report AOCI on our Consolidated Condensed Balance Sheets. The table below details the components of our comprehensive income (loss) during the three and six months ended June 30, 2009 and 2008 (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Net income (loss)	$ (79)	$ 197	$ (48)	$ (17)
Other comprehensive income (loss):				
Gain (loss) on cash flow hedges before reclassification adjustment for cash flow hedges realized in net income (loss)	108	(168)	310	(572)
Reclassification adjustment for cash flow hedges realized in net income (loss)	(118)	12	(185)	22
Foreign currency translation gain (loss)	3	—	1	(6)
Income tax benefit (expense)	14	(4)	27	(4)
Total comprehensive income (loss)	$ (72)	$ 37	$ 105	$ (577)

6. Debt

Our debt at June 30, 2009, and December 31, 2008, was as follows (in millions):

	June 30, 2009	December 31, 2008
Exit Credit Facility	$ 6,615	$ 6,645
Commodity Collateral Revolver	100	100
Project financing	1,614	1,525
CCFC New Notes	956	—
CCFC Old Notes and CCFC Term Loans	—	778
Preferred interests	294	335
Notes payable and other borrowings	305	356
Capital lease obligations	705	733
Total debt	10,589	10,472
Less: Current maturities	634	716
Debt, net of current portion	$ 9,955	$ 9,756

Exit Credit Facility — As of June 30, 2009, and December 31, 2008, our primary debt facility was the Exit Credit Facility. The Exit Credit Facility includes approximately $6.0 billion of senior secured term loans, a $1.0 billion senior secured revolver, and the ability, subject to market conditions, to raise up to $2.0 billion of incremental term loans available on a senior secured basis in order to refinance secured debt of subsidiaries under an "accordion" provision.

As of June 30, 2009, under the Exit Credit Facility we had approximately $5.9 billion outstanding under the term loan facilities, $725 million outstanding under the revolver and $220 million of letters of credit issued against the revolver. Borrowings under the Exit Credit Facility bear interest at a floating rate, at our option, of LIBOR plus 2.875% per annum or base rate plus 1.875% per annum. Borrowings under the Exit Credit Facility term loan facility require quarterly payments of principal equal to 0.25% of the original principal amount of the term loan. The Exit Credit Facility matures on March 29, 2014.

The obligations under the Exit Credit Facility are unconditionally guaranteed by certain of our direct and indirect domestic subsidiaries and are secured by a security interest in substantially all of the tangible and intangible assets of Calpine Corporation and the guarantors. The obligations under the Exit Credit Facility are also secured by a pledge of the equity interests of the direct subsidiaries of each guarantor, subject to certain exceptions, including exceptions for equity interests in foreign subsidiaries, existing contractual prohibitions and prohibitions under other legal requirements. The Exit Credit Facility contains restrictions, including limiting our ability to, among other things:

- incur additional indebtedness and issue stock;
- make prepayments on or purchase indebtedness in whole or in part;
- pay dividends and other distributions with respect to our stock or repurchase our stock or make other restricted payments;
- use money borrowed under the Exit Credit Facility for non-guarantors (including foreign subsidiaries);
- make certain investments;
- create or incur liens to secure debt;
- consolidate or merge with another entity, or allow one of our subsidiaries to do so;
- lease, transfer or sell assets and use proceeds of permitted asset leases, transfers or sales;
- limit dividends or other distributions from certain subsidiaries up to Calpine Corporation;
- make capital expenditures beyond specified limits;
- engage in certain business activities; and
- acquire power plants or other businesses.

The Exit Credit Facility also requires compliance with financial covenants that include a maximum ratio of total net debt to Consolidated EBITDA (as defined in the Exit Credit Facility), a minimum ratio of Consolidated EBITDA to cash interest expense, and a maximum ratio of total senior net debt to Consolidated EBITDA.

CCFC Refinancing — On May 19, 2009, CCFC and CCFC Finance issued $1.0 billion in aggregate principal amount of CCFC New Notes in a private placement. Interest on the CCFC New Notes accrues at the rate of 8.0% per annum and is payable semi-annually in arrears on each June 1 and December 1, commencing on December 1, 2009. The CCFC New Notes which mature on June 1, 2016, are guaranteed by two of CCFC's subsidiaries. The CCFC New Notes and the related guarantees are secured, subject to certain exceptions and permitted liens, by all real and personal property of CCFC and CCFC's material subsidiaries (including the CCFC Guarantors), consisting primarily of six natural gas power plants as well as the equity interests in CCFC and the CCFC Guarantors. The net proceeds received of $939 million, together with CCFC cash on hand of $271 million, were used to:

- repay the $364 million outstanding under the CCFC Term Loans on May 19, 2009;
- redeem the $415 million outstanding principal amount of CCFC Old Notes on June 18, 2009;
- distribute $327 million to CCFC's indirect parent, CCFCP, which was used by CCFCP to redeem its $300 million CCFCP Preferred Shares on or before July 1, 2009; and
- in each case, pay any interest, prepayment penalties and other amounts due through the date of such repayment or redemption.

In connection with the CCFC Refinancing, we recorded $33 million in debt extinguishment costs for the three and six months ended June 30, 2009, from the write-off of unamortized deferred financing costs and unamortized debt discount of $7 million and prepayment penalties of $24 million related to the CCFC Old Notes, and $2 million related to the CCFCP Preferred Shares redeemed on or before June 30, 2009. These items are recorded in debt extinguishment costs on our Consolidated Condensed Statements of Operations for the three and six months ended June 30, 2009. We also recorded approximately $21 million in new deferred financing costs on our Consolidated Condensed Balance Sheet at June 30, 2009.

We offered early redemption prior to July 1, 2009, to each holder of the CCFCP Preferred Shares. As of June 30, 2009, $36 million of the CCFCP Preferred Shares had been redeemed. The remaining $264 million is reported as debt, current portion on our Consolidated Condensed Balance Sheet. This balance was redeemed on July 1, 2009, and we recorded an additional $15 million in debt extinguishment costs related to prepayment penalties and the write-off of unamortized deferred financing costs on July 1, 2009.

Other Financing Activities — On January 21, 2009, Deer Park, our indirect wholly owned subsidiary, closed on $156 million of senior secured credit facilities, which include a $150 million term facility and a $6 million letter of credit facility. Proceeds received were used to settle an existing commodity contract of approximately $79 million, pay financing and legal fees of approximately $8 million and fund approximately $22 million in restricted cash. The remainder was distributed to Calpine Corporation for general corporate purposes. The senior term loan facility matures on January 21, 2012, and bears interest of LIBOR plus 3.5% or base rate plus 2.5% at Deer Park's option.

Letter of Credit Facilities — The table below represents amounts outstanding under our letter of credit facilities as of June 30, 2009, and December 31, 2008 (in millions):

	June 30, 2009	December 31, 2008
Exit Credit Facility	$ 220	$ 259
Calpine Development Holdings, Inc.	148	148
Knock-in Facility(1)	—	50
Various project financing facilities	98	99
Total	$ 466	$ 556

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(1) The Knock-in Facility matured on June 30, 2009, and is no longer available.

Fair Value of Debt

We did not elect to apply the alternative GAAP provisions of the fair value option for recording financial assets and financial liabilities. We record our debt instruments based on contractual terms, net of any applicable premium or discount. We measured the fair value of our debt instruments as of June 30, 2009, and December 31, 2008, using market information including credit default swap rates and historical default information, quoted market prices or dealer quotes for the identical liability when traded as an asset and discounted cash flow analyses based on our current borrowing rates for similar types of borrowing arrangements. The following table details the fair values and carrying values of our debt instruments as of June 30, 2009, and December 31, 2008 (in millions):

	June 30, 2009		December 31, 2008	
	Fair Value	Carrying Value	Fair Value	Carrying Value
Exit Credit Facility	$ 5,954	$ 6,615	$ 4,812	$ 6,645
Commodity Collateral Revolver	90	100	85	100
Project financing	1,559	1,614	1,420	1,525
CCFC New Notes	963	956	—	—
CCFC Old Notes and CCFC Term Loans	—	—	727	778
Preferred interests	294	294	305	335
Notes payable and other borrowings	285	305	330	356
Total	$ 9,145	$ 9,884	$ 7,679	$ 9,739

7. Fair Value Measurements

Derivatives — We enter into a variety of derivative instruments including both exchange traded and OTC power and natural gas forwards, options, instruments that settle on power price to natural gas price relationships (Heat Rate swaps and options) and interest rate swaps.

Our level 1 fair value derivative instruments primarily consist of natural gas futures and options traded on the NYMEX.

Our level 2 fair value derivative instruments primarily consist of our interest rate swaps and our OTC power and natural gas forwards where market data for pricing inputs is observable. Generally, we obtain our level 2 pricing inputs from markets such as the Intercontinental Exchange. In certain instances, our level 2 derivative instruments may utilize models to measure fair value. These models are primarily industry-standard models that incorporate various assumptions, including quoted interest rates and time value, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

Our level 3 fair value derivative instruments primarily consist of our OTC power and natural gas forwards and options where pricing inputs are unobservable, as well as other complex and structured transactions. Complex or structured transactions are tailored to our or our customers' needs and can introduce the need for internally-developed model inputs which might not be observable in or corroborated by the market. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized in level 3. Our valuation models may incorporate historical correlation information and extrapolate available broker and other information to future periods. In cases where there is no corroborating market information available to support significant model inputs, we initially use the transaction price as the best estimate of fair value. OTC options are valued using industry-standard models, including the Black-Scholes pricing model. At each balance sheet date, we perform an analysis of all instruments subject to fair value measurement and include in level 3 all of those whose fair value is based on significant unobservable inputs.

We utilize market data (such as pricing services and broker quotes) and assumptions that we believe market participants would use in pricing our assets or liabilities including assumptions about risks and the risks inherent to the inputs in the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. The market data obtained from broker pricing services is evaluated to determine the nature of the quotes obtained and, where accepted as a reliable quote, used to validate our assessment of fair value; however, other qualitative assessments are used to determine the level of activity in any given market. We primarily apply the market approach and income approach for recurring fair value measurements and utilize what we believe to be the best available information. We utilize valuation techniques that seek to maximize the use of observable inputs and minimize the use of unobservable inputs. We classify fair value balances based on the observability of those inputs.

The primary factors affecting the fair value of our commodity derivatives at any point in time are the volume of open derivative positions (MMBtu and MWh), changing commodity market prices, principally for power and natural gas, the credit standing of our counterparties, changing interest rates and our own credit rating. Prices for power and natural gas are volatile, which can result in material changes in the fair value measurements reported in our financial statements in the future.

The fair value of our derivatives includes consideration of the credit standing of the counterparties involved and the impact of credit enhancements, if any. We have also recorded credit reserves in the determination of fair value based on our expectation of how market participants would determine fair value. Such valuation adjustments are generally based on market evidence, if available, or our best estimate.

Margin Deposits — Our margin deposits are cash and cash equivalents and are generally classified within level 1 of the fair value hierarchy as the amounts approximate fair value.

The following tables present our financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2009, and December 31, 2008, by level within the fair value hierarchy. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

	Recurring Fair Value Measures at Fair Value as of June 30, 2009			
	Level 1	Level 2	Level 3	Total
	(in millions)			
Assets:				
Commodity derivatives	$ 2,872	$ 728	$ 148	$ 3,748
Interest rate derivatives	—	—	—	—
Total derivative assets	2,872	728	148	3,748
Cash equivalents(1)	1,525	—	—	1,525
Margin deposits(2)	476	—	—	476
Total	$ 4,873	$ 728	$ 148	$ 5,749
Liabilities:				
Commodity derivatives	$ 2,837	$ 453	$ 57	$ 3,347
Interest rate derivatives	—	363	—	363
Total derivative liabilities	2,837	816	57	3,710
Margin deposits held by us posted by our counterparties(2)	2	—	—	2
Total	$ 2,839	$ 816	$ 57	$ 3,712

	Recurring Fair Value Measures at Fair Value as of December 31, 2008			
	Level 1	Level 2	Level 3	Total
	(in millions)			
Assets:				
Commodity derivatives	$ 3,263	$ 634	$ 160	$ 4,057
Interest rate derivatives	—	—	—	—
Total derivative assets	3,263	634	160	4,057
Cash equivalents(1)	2,092	—	—	2,092
Margin deposits(2)	653	—	—	653
Total	$ 6,008	$ 634	$ 160	$ 6,802
Liabilities:				
Commodity derivatives	$ 3,515	$ 475	$ 55	$ 4,045
Interest rate derivatives	—	452	—	452
Total derivative liabilities	3,515	927	55	4,497
Margin deposits held by us posted by our counterparties(2)	169	—	—	169
Total	$ 3,684	$ 927	$ 55	$ 4,666

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(1) Amounts represent cash equivalents invested in money market accounts and are included in cash and cash equivalents and restricted cash on our Consolidated Condensed Balance Sheets. As of June 30, 2009, and December 31, 2008, we had cash equivalents of $1,094 million and $1,597 million included in cash and cash equivalents and $431 million and $495 million included in restricted cash, respectively.

(2) Margin deposits and margin deposits held by us posted by our counterparties represent cash collateral paid between our counterparties and us to support our commodity contracts.

Gains or losses associated with level 3 balances may not necessarily reflect trends occurring in the underlying business. Further, unrealized gains and losses for the period from level 3 items are often offset by unrealized gains and losses on positions classified in level 1 or 2, as well as positions that have been realized during the quarter. Certain of our level 3 balances qualify for hedge accounting for which any unrealized gains and losses are recorded in OCI. Gains and losses for level 3 balances that do not qualify for hedge accounting are recorded in earnings.

The following table sets forth a reconciliation of changes in the fair value of our net derivatives classified as level 3 in the fair value hierarchy for the three and six months ended June 30, 2009 and 2008 (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Balance, beginning of period	$ 114	$ (560)	$ 105	$ (23)
Realized and unrealized gains (losses):				
Included in net income (loss)(1)	(4)	107	11	(153)
Included in OCI	5	(470)	18	(955)
Purchases, issuances and settlements, net	(13)	119	(26)	248
Transfers in and/or out of level 3(2)	(11)	155	(17)	234
Balance, end of period	$ 91	$ (649)	$ 91	$ (649)
Change in unrealized gains and (losses) relating to instruments still held as of June 30, 2009 and 2008	$ (4)(1)	$ 107(1)	$ 11(1)	$ (157)(3)

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(1) Includes $(1) million and $3 million recorded in operating revenues (for power contracts and Heat Rate swaps and options) and $(3) million and $8 million recorded in fuel and purchased energy expense (for natural gas contracts) for the three and six months ended June 30, 2009, respectively, and includes $3 million and $(174) million recorded in operating revenues (for power contracts and Heat Rate swaps and options) and $104 million and $21 million recorded in fuel and purchased energy expense (for natural gas contracts) for the three and six months ended June 30, 2008, respectively, as shown on our Consolidated Condensed Statements of Operations.

(2) We transfer amounts among levels of the fair value hierarchy as of the end of each period.

(3) Includes $(201) million recorded in operating revenues (for power contracts and Heat Rate swaps and options) and $44 million recorded in fuel and purchased energy expense (for natural gas contracts), as shown on our Consolidated Condensed Statement of Operations for the six months ended June 30, 2008.

8. Derivative Instruments and Collateral

The table below reflects the amounts that are recorded as derivative assets and liabilities on our Consolidated Condensed Balance Sheets at June 30, 2009, and December 31, 2008, for our derivative instruments (in millions):

	June 30, 2009		
	Interest Rate Swaps	**Commodity Instruments**	**Total Derivative Instruments**
Current derivative assets	$ —	$ 3,361	$ 3,361
Long-term derivative assets	—	387	387
Total derivative assets	$ —	$ 3,748	$ 3,748
Current derivative liabilities	$ 214	$ 3,017	$ 3,231
Long-term derivative liabilities	149	330	479
Total derivative liabilities	$ 363	$ 3,347	$ 3,710
Net derivative assets (liabilities)	$ (363)	$ 401	$ 38

	December 31, 2008		
	Interest Rate Swaps	**Commodity Instruments**	**Total Derivative Instruments**
Current derivative assets	$ —	$ 3,653	$ 3,653
Long-term derivative assets	—	404	404
Total derivative assets	$ —	$ 4,057	$ 4,057
Current derivative liabilities	$ 179	$ 3,620	$ 3,799
Long-term derivative liabilities	273	425	698
Total derivative liabilities	$ 452	$ 4,045	$ 4,497
Net derivative assets (liabilities)	$ (452)	$ 12	$ (440)

We adopted the new accounting requirements related to disclosures about derivative instruments and hedging activities as of January 1, 2009, which require enhanced disclosures about an entity's derivative and hedging activities to enable investors to better understand their effects on the entity's financial position, financial performance, and cash flows as well as qualitative disclosures about our fair value amounts of gains and losses associated with derivative instruments and disclosures about credit-risk-related contingent features in derivative agreements.

Commodity Instruments — We are susceptible to changes in prices for the purchase and sale of power, natural gas and other energy commodities. We utilize derivatives, which include physical commodity contracts and financial commodity instruments such as swaps and options and NYMEX contracts to attempt to maximize the risk-adjusted returns by economically hedging a portion of the commodity price risk associated with our assets. These transactions primarily act as fair value and cash flow hedges. By entering into these transactions, we are able to economically hedge a portion of our spark spread at pre-determined generation and price levels.

Interest Rate Swaps — A significant portion of our debt is indexed to base rates, primarily LIBOR. We utilize interest rate swaps to adjust the mix between fixed and floating rate debt to hedge our interest rate risk for potential adverse changes in interest rates. These transactions act as economic hedges for our interest cash flow.

As of June 30, 2009, the maximum length of our PPAs extend until 24 years into the future and the maximum length of time over which we were hedging using commodity and interest rate derivative instruments was 4 and 17 years, respectively.

Accounting for Derivative Instruments

We recognize all derivative instruments that qualify for derivative accounting treatment as either assets or liabilities and measure those instruments at fair value unless they qualify for and we elect the normal purchases or normal sales exemption. Revenues derived from these instruments that qualify for hedge accounting are recorded on a net basis in the period that the hedged item is recognized in earnings. Hedge accounting requires us to formally document, designate and assess the effectiveness of transactions that receive hedge accounting. We present the cash flows from our derivatives in the same category as the item being hedged within operating activities on our Consolidated Condensed Statements of Cash Flows unless they contain an other-than-insignificant financing element in which case their cash flows are classified within financing activities.

Cash Flow Hedges — We report the effective portion of the unrealized gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument as a component of OCI and reclassify such gains and losses into earnings in the same period during which the hedged forecasted transaction affects earnings. Gains and losses due to ineffectiveness on commodity hedging instruments are included in unrealized mark-to-market gains and losses and are recognized currently in earnings as a component of operating revenues (for power contracts), fuel and purchased energy expense (for natural gas contracts) and interest expense (for interest rate swaps). If it is determined that the forecasted transaction is no longer probable of occurring, then hedge accounting will be discontinued prospectively and the associated gain or loss previously deferred in OCI is reclassified into current income. If the hedging instrument is terminated or de-designated prior to the occurrence of the hedged forecasted transaction, the gain or loss associated with the hedge instrument remains deferred in OCI until such time as the forecasted transaction impacts earnings, or until it is determined that the forecasted transaction is no longer probable of occurring.

Fair Value Hedges — 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 or liability, or unrecognized firm commitment is recorded in earnings. If the fair value hedge is effective, the amounts recorded will offset in earnings. If the underlying asset, liability or firm commitment being hedged is disposed of or otherwise terminated, the gain or loss associated with the underlying hedged item is recognized currently in earnings. If the hedging instrument is terminated or de-designated prior to the settlement of the hedged asset, liability or firm commitment, the carrying amount of the hedged item is adjusted by any gain or loss from the hedging instrument and remains until the hedged item is recognized in earnings.

Derivatives Not Designated as Hedging Instruments — Along with our portfolio of hedging transactions, we enter into power, natural gas and interest rate transactions that primarily act as economic hedges to our asset portfolio, but either do not qualify as hedges under hedge accounting criteria guidelines or qualify under the hedge accounting guidelines and the hedge accounting designation has not been elected, such as commodity options transactions and instruments that settle on power price to natural gas price relationships (Heat Rate swaps and options). Changes in fair value of derivatives not designated as hedging instruments are recognized currently in earnings as a component of operating revenues (for power contracts and Heat Rate swaps and options), fuel and purchased energy expense (for natural gas contracts) and interest expense (for interest rate swaps).

Derivatives Included on Our Consolidated Condensed Balance Sheet

The following table presents the fair values and locations of our net derivative instruments recorded in our Consolidated Condensed Balance Sheet at June 30, 2009 (in millions):

	Fair Value of Derivative Assets(1)	Fair Value of Derivative Liabilities(2)
Derivatives designated as cash flow hedging instruments:		
Interest rate swaps	$ —	$ 346
Commodity instruments	626	171
Total derivatives designated as cash flow hedging instruments	$ 626	$ 517
Derivatives designated in fair value hedging relationships:		
Commodity instruments, hedging instrument	$ —	$ 42
Commodity instruments, hedged item	42	—
Total derivatives designated in fair value hedging relationships	$ 42	$ 42
Derivatives not designated as hedging instruments:		
Interest rate swaps	$ —	$ 17
Commodity instruments	3,080	3,134
Total derivatives not designated as hedging instruments	$ 3,080	$ 3,151
Total derivatives	$ 3,748	$ 3,710

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(1) Included in derivative assets on our Consolidated Condensed Balance Sheet as of June 30, 2009.

(2) Included in derivative liabilities on our Consolidated Condensed Balance Sheet as of June 30, 2009.

We execute forward physical and financial commodity purchase and sales agreements to hedge our exposure to underlying commodity risk. Through hedging and optimization activities it is not uncommon for us to purchase and sell forward natural gas and power in both the physical and financial markets. As of June 30, 2009, the net forward notional buy (sell) position of our outstanding commodity and interest rate swap contracts that do not qualify under the normal purchases or normal sales exemption are as follows (in millions):

Derivative Instruments	Notional Volumes
Power (MWh)	(62)
Natural gas (MMBtu)	113
Interest rate swaps	$ 7,105

Certain of our derivative instruments contain credit-contingent provisions that require us to maintain our current credit rating or higher from each of the major credit rating agencies. If our credit rating were to be downgraded, it could require us to post additional collateral or could potentially allow our counterparty to request immediate, full settlement on certain derivative instruments in liability positions. The aggregate fair value of our derivative liabilities with credit-contingent provisions as of June 30, 2009, was $112 million for which we have posted collateral of $55 million from margin deposits or granted additional first priority liens on the assets currently subject to first priority liens under our Exit Credit Facility. However, if our credit rating were downgraded by one rating level, we estimate that any additional collateral would not be material and that no counterparty could request immediate, full settlement.

Derivatives Included on Our Consolidated Condensed Statements of Operations, OCI and AOCI

Changes in the fair values of our derivative instruments (both assets and liabilities) are reflected either in cash for option premiums paid or collected, in OCI, net of tax for the effective portion of derivative instruments which qualify for cash flow hedge accounting treatment, or on our Consolidated Condensed Statements of Operations as a component of mark-to-market activity within our net income (loss).

The table below details the components of our total mark-to-market activity which includes the realized and unrealized gains (losses) recognized from our derivative instruments not designated as hedging instruments and the ineffectiveness related to our hedging instruments and where they are recorded on our Consolidated Condensed Statements of Operations for the three and six months ended June 30, 2009 and 2008 (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Power contracts included in operating revenues	$ (49)	$ (8)	$ (9)	$ (104)
Natural gas contracts included in fuel and purchased energy expense	(15)	32	12	(23)
Interest rate swaps included in interest expense	(2)	12	(5)	(4)
Total mark-to-market activity	$ (66)	$ 36	$ (2)	$ (131)

The following table details the effect of our net derivative instruments that qualify for hedge accounting treatment on our Consolidated Condensed Statements of Operations, OCI and AOCI for the three and six months ended June 30, 2009 (in millions):

	Gain (Loss) Recognized in OCI (Effective Portion)		Gain (Loss) Reclassified from AOCI into Income (Effective Portion)		Gain (Loss) Reclassified from AOCI into Income (Ineffective Portion)	
	Three Months Ended June 30, 2009	Six Months Ended June 30, 2009	Three Months Ended June 30, 2009	Six Months Ended June 30, 2009	Three Months Ended June 30, 2009	Six Months Ended June 30, 2009
Interest rate swaps	$ 80	$ 87	$ (48)(1)	$ (92)(1)	$ —	$ —
Commodity instruments	(90)	38	166(2)	277(2)	(1)(2)(3)	—
Total	$ (10)	$ 125	$ 118	$ 185	$ (1)	$ —

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(1) Included in interest expense on our Consolidated Condensed Statements of Operations.

(2) Included in operating revenues and fuel and purchased energy expense on our Consolidated Condensed Statements of Operations.

(3) The ineffective portion of gains (losses) reclassified from AOCI into income on commodity hedging instruments was $(1) million and $5 million for the three and six months ended June 30, 2008, respectively.

Assuming constant June 30, 2009 power and natural gas prices and interest rates, we estimate that pre-tax, net gains of $161 million would be reclassified from AOCI into earnings during the next 12 months as the hedged transactions settle; however, the actual amounts that will be reclassified will likely vary based on changes in natural gas and power prices as well as interest rates. Therefore, we are unable to predict what the actual reclassification from AOCI to earnings (positive or negative) will be for the next 12 months.

The following table details the net unrealized gain (loss) from our net derivative instruments on our Consolidated Condensed Statements of Operations for the three and six months ended June 30, 2009, which do not qualify as hedges under the hedge accounting guidelines or qualify under the hedge accounting guidelines and the hedge accounting designation has not been elected (in millions):

	Gain (Loss) in Income	
	Three Months Ended June 30, 2009	Six Months Ended June 30, 2009
Interest rate swaps(1)	$ 5	$ 6
Commodity instruments(2)	(108)	17
Total	$ (103)	$ 23

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(1) Included in interest expense on our Consolidated Condensed Statements of Operations.

(2) Included in operating revenues and fuel and purchased energy expense on our Consolidated Condensed Statements of Operations.

Collateral — We use margin deposits, prepayments and letters of credit as credit support with and from our counterparties for commodity procurement and risk management activities. In addition, we have granted additional first priority liens on the assets currently subject to first priority liens under the Exit Credit Facility as collateral under certain of our power and natural gas agreements that qualify as "eligible commodity hedge agreements" under the Exit Credit Facility and certain of our interest rate swap agreements in order to reduce the cash collateral and letters of credit that we would otherwise be required to provide to the counterparties under such agreements. The counterparties under such agreements would share the benefits of the collateral subject to such first priority liens ratably with the lenders under the Exit Credit Facility.

The table below summarizes the balances outstanding under margin deposits, natural gas and power prepayments, and exposure under letters of credit and first priority liens for commodity procurement and risk management activities as of June 30, 2009, and December 31, 2008 (in millions):

	June 30, 2009	December 31, 2008
Margin deposits(1)	$ 476	$ 653
Natural gas and power prepayments	54	60
Total margin deposits and natural gas and power prepayments with our counterparties(2)	$ 530	$ 713
Letters of credit issued	$ 370	$ 455
First priority liens under power and natural gas agreements(3)	2	—
First priority liens under interest rate swap agreements	360	477
Total letters of credit and first priority liens with our counterparties	$ 732	$ 932
Margin deposits held by us posted by our counterparties(1)(4)	$ 2	$ 169
Letters of credit posted with us by our counterparties	225	95
Total margin deposits and letters of credit posted with us by our counterparties	$ 227	$ 264

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(1) Balances are subject to master netting agreements and presented on a gross basis on our Consolidated Condensed Balance Sheets.

(2) At June 30, 2009 and December 31, 2008, $509 million and $693 million are included in margin deposits and other prepaid expense, respectively, and $21 million and $20 million are included in other assets on our Consolidated Condensed Balance Sheets, respectively.

(3) The fair value of our commodity derivatives collateralized by first priority liens include assets of $308 million and a liability of $(2) million at June 30, 2009, and assets of $201 million at December 31, 2008. We only include our liabilities in our table above as our commodity derivative assets have no collateral exposure on the balance sheet date.

(4) Included in other current liabilities on our Consolidated Condensed Balance Sheets.

Future collateral requirements for cash, first priority liens and letters of credit may increase or decrease based on the extent of our involvement in hedging and optimization contracts, movements in commodity prices, and also based on our credit ratings and general perception of creditworthiness in our market.

9. Earnings (Loss) per Share

Pursuant to the Plan of Reorganization, all shares of our common stock outstanding prior to the Effective Date were canceled and the issuance of 485 million new shares of reorganized Calpine Corporation common stock was authorized to resolve allowed unsecured claims. A portion of the 485 million authorized shares was immediately distributed, and the remainder was reserved for distribution to holders of certain disputed claims that, although unresolved as of the Effective Date, later become allowed. To the extent that any of the reserved shares remain undistributed upon resolution of the disputed claims, such shares will not be returned to us but rather will be distributed pro rata to claimants with allowed claims to increase their recovery. Therefore, pursuant to the Plan of Reorganization, all 485 million shares ultimately will be distributed. Accordingly, although the reserved shares are not yet issued and outstanding, all conditions of distribution had been met for these reserved shares as of the Effective Date, and such shares are considered issued and are included in our calculation of weighted average shares outstanding. We also include restricted stock units for which no future service is required as a condition to the delivery of the underlying common stock in our calculation of weighted average shares outstanding.

Reconciliations of the amounts used in the basic and diluted earnings (loss) per common share computations for the three and six months ending June 30, 2009 and 2008, are:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(shares in thousands)			
Diluted weighted average shares calculation:				
Weighted average shares outstanding (basic)	485,675	485,004	485,560	485,002
Restricted stock awards	—	723	—	—
Employee stock options	—	5	—	—
Weighted average shares outstanding (diluted)	485,675	485,732	485,560	485,002

As we incurred a net loss for the three and six months ended June 30, 2009, and the six months ended June 30, 2008, diluted loss per share for those periods is computed on the same basis as basic loss per share as the inclusion of any other potential shares outstanding would be anti-dilutive. We excluded the following potentially dilutive securities from our calculation of diluted earnings (loss) per common share for the three and six months ended June 30, 2009 and 2008:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
	(shares in thousands)			
Restricted stock awards(1)	368	—	831	503
Employee stock options(1)	13,171	4,760	12,977	3,652
Common stock warrants(1)(2)	—	48,497	—	36,507

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(1) Excluded from diluted weighted average shares as these equity-based instruments are anti-dilutive due to the net loss incurred during the period or in accordance with the calculation under the treasury stock method prescribed by GAAP.

(2) Pursuant to the Plan of Reorganization, holders of allowed interests (primarily holders of our old common stock canceled on the Effective Date) received a pro rata share of warrants to purchase approximately 48.5 million shares of our new, reorganized Calpine Corporation common stock at $23.88 per share. Warrants for 21,499 shares of common stock were exercised prior to expiration. The remaining warrants expired unexercised on August 25, 2008.

10. Stock-Based Compensation

The Calpine Equity Incentive Plans were approved as part of our Plan of Reorganization. These plans are administered by the Compensation Committee of our Board of Directors and provide for the issuance of equity awards to all employees as well as the non-employee members of our Board of Directors. The equity awards may include incentive or non-qualified stock options, restricted stock, restricted stock units, stock appreciation rights, performance compensation awards and other stock-based awards. Under the MEIP and DEIP there are 14,833,000 shares and 167,000 shares, respectively, of our common stock authorized for issuance to participants.

The equity awards granted under the Calpine Equity Incentive Plans include both graded and cliff vesting options which vest over periods between one and five years, contain contractual terms of seven and ten years and are subject to forfeiture provisions under certain circumstances including termination of employment prior to vesting. In addition, employment inducement options to purchase a total of 4,636,734 shares were granted outside of the Calpine Equity Incentive Plans in connection with our hiring of a new Chief Executive Officer and a new Chief Legal Officer in August 2008, and a new Chief Commercial Officer in September 2008. No grants of options or shares of restricted stock were made outside of the Calpine Equity Incentive Plans during the six months ended June 30, 2009. Each of the employment inducement options vests over a period of five years, contains a contractual term of seven years and is subject to forfeiture under certain circumstances including termination of employment prior to vesting.

We use the Black-Scholes option-pricing model to estimate the fair value of our employee stock options or its equivalent on the grant date, which takes into account the exercise price and expected life of the stock option, the current price of the underlying stock and its expected volatility, expected dividends on the stock, and the risk-free interest rate for the expected term of the stock option as of the grant date. For our restricted stock and restricted stock units, we use our closing stock price on the date of grant or the last trading day preceding the grant date, for restricted stock granted on non-trading days, as the fair value for measuring compensation expense. Compensation expense is recognized over the period in which the related employee services are rendered. The service period is generally presumed to begin on the grant date and end when the equity award is fully vested. We use the graded vesting attribution method to recognize fair value of the equity award over the service period. For example, the graded vesting attribution method views one three-year option grant with annual graded vesting as three separate sub-grants, each representing 33 1/3% of the total number of stock options granted. The first sub-grant vests over one year, the second sub-grant vests over two years and the third sub-grant vests over three years. A three-year option grant with cliff vesting is viewed as one grant vesting over three years.

Stock-based compensation expense recognized was $9 million and $13 million for the three months ended June 30, 2009 and 2008, respectively, and $22 million and $19 million for the six months ended June 30, 2009 and 2008, respectively. We did not record any tax benefits related to stock-based compensation expense in any period as we are not benefiting from a significant portion of our deferred tax assets including deductions related to stock-based compensation expense. In addition, we did not capitalize any stock-based compensation expense as part of the cost of an asset for the three and six months ended June 30, 2009 and 2008. At June 30, 2009, there was $56 million of unrecognized compensation cost related to equity awards, which is expected to be recognized over a weighted average period of 2.0 years for options, 2.1 years for restricted shares and 0.9 years for restricted stock units. We issue new shares from our reserves set aside for our MEIP, DEIP and employment inducement options when stock options are exercised and for other stock-based awards.

A summary of all of our non-qualified stock option activity for the MEIP and DEIP for the six months ended June 30, 2009, is as follows:

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Term (in years)	Aggregate Intrinsic Value (in millions)
Outstanding – December 31, 2008	12,840,754	$ 19.72	7.5	$ —
Granted	911,500	$ 9.42		
Exercised	—	$ —		
Forfeited	152,424	$ 17.96		
Expired	147,358	$ 17.22		
Outstanding – June 30, 2009	13,452,472	$ 19.07	7.1	$ 2
Exercisable – June 30, 2009	2,429,878	$ 17.33	8.4	$ —
Vested and expected to vest – June 30, 2009	13,130,520	$ 19.19	7.1	$ 2

There were no employee stock options exercised during the six months ended June 30, 2009 and 2008.

The fair value of options granted during the six months ended June 30, 2009 and 2008, was determined on the grant date using the Black-Scholes pricing model. Certain assumptions were used in order to estimate fair value for options as noted in the following table.

	2009	2008
Expected term (in years)(1)	6.0 – 6.5	5.4 – 6.1
Risk-free interest rate(2)	2.3 – 2.9%	2.7 – 3.3%
Expected volatility(3)	60.1 – 73.0%	34.8 – 40.9%
Dividend yield(4)	—	—
Weighted average grant-date fair value (per option)	$ 5.66	$ 7.22

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(1) Expected term calculated using the simplified method prescribed by the SEC.

(2) Zero Coupon U.S. Treasury rate or equivalent based on expected term.

(3) For the six months ended June 30, 2009, we calculated volatility using the implied volatility of our exchange traded stock options. For the six months ended June 30, 2008, we calculated volatility using the weighted average implied volatility of our industry peers' exchange traded stock options.

(4) We are currently prohibited under the Exit Credit Facility and certain of our other debt agreements from paying any cash dividends on our common stock.

No restricted stock or restricted stock units have been granted other than under our MEIP and DEIP. A summary of our restricted stock and restricted stock unit activity for the MEIP and DEIP for the six months ended June 30, 2009, is as follows:

	Number of Restricted Stock Awards	Weighted Average Grant-Date Fair Value
Nonvested – December 31, 2008	1,742,242	$ 16.69
Granted	1,468,616	$ 9.49
Forfeited	109,256	$ 15.43
Vested	772,250	$ 16.67
Nonvested – June 30, 2009	2,329,352	$ 12.21

The total fair value of our restricted stock and restricted stock units that vested during the six months ended June 30, 2009 and 2008, was $6 million and nil, respectively.

11. Our Emergence from Chapter 11

From December 20, 2005, through January 31, 2008, the U.S. Debtors operated as debtors-in-possession under the protection of the U.S. Bankruptcy Court. In addition, the Canadian Debtors operated as debtors-in-possession under the jurisdiction of the Canadian Court from December 20, 2005, through February 8, 2008, the date on which the Canadian Court ordered and declared that the Canadian Debtors' proceedings under the CCAA were terminated.

Our Plan of Reorganization provides for the treatment of claims against and interests in the U.S. Debtors. Allowed administrative, tax and secured claims generally have been or are being paid in cash and cash equivalents or, with respect to certain secured claims, had the collateral securing such claims returned to the secured creditor. Allowed unsecured claims generally have been or are being paid with a distribution of common stock. Pursuant to the Plan of Reorganization, 485 million shares of common stock were authorized to be issued to settle such claims.

Through the filing of this Report, approximately 439 million shares have been distributed to holders of allowed unsecured claims and approximately 46 million shares remain in reserve for distribution to holders of disputed claims whose claims ultimately become allowed. We estimate that the number of shares reserved is sufficient to satisfy the U.S. Debtors' obligations under the Plan of Reorganization even if all disputed unsecured claims ultimately become allowed. As disputed claims are resolved, the claimants receive distributions of shares from the reserve on the same basis as if such distributions had been made on or about the Effective Date. To the extent that any of the reserved shares remain undistributed upon resolution of the remaining disputed claims, such shares will not be returned to us but rather will be distributed pro rata to claimants with allowed claims to increase their recovery. We are not required to issue additional shares above the 485 million shares authorized to settle unsecured claims, even if the shares remaining for distribution are not sufficient to fully pay all allowed unsecured claims. Accordingly, resolution of these claims could have a material effect on creditor recoveries under the Plan of Reorganization as the total number of shares of common stock that remain available for distribution upon resolution of disputed claims is limited pursuant to the Plan of Reorganization. However, certain disputed claims, including prepayment premium and default interest claims asserted by the holders of CalGen Third Lien Debt, may be required to be settled with available cash and cash equivalents to the extent reorganized Calpine Corporation common stock held in reserve pursuant to the Plan of Reorganization for such claims is insufficient in value to satisfy such claims in full. No assurances can be given that settlements may not be materially higher or lower than confirmed in the Plan of Reorganization or than we originally estimated.

Reorganization Items — Reorganization items represent the direct and incremental costs related to our Chapter 11 cases. These include professional and trustee fees, pre-petition liability claim adjustments and losses that are probable and can be estimated, net of interest income earned on accumulated cash during the Chapter 11 process and net of gains on the sale of assets or resulting from certain settlement agreements related to our restructuring activities. We expect to continue to pay professional and trustee fees related to our Chapter 11 cases through 2009 and thereafter until the claims resolution process is completed and our Chapter 11 case is formally dismissed by the U.S. Bankruptcy Court.

The table below lists the significant components of reorganization items for the three and six months ended June 30, 2009 and 2008 (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Provision for expected allowed claims	$ 2	$ 5	$ 2	$ (54)
Professional and trustee fees	1	14	4	76
Gains on asset sales	—	—	—	(203)
Loss (gain) on reconsolidation of Canadian Debtors and other foreign entities	—	5	—	(65)
Interest (income) on accumulated cash	—	—	—	(7)
Other	—	(6)	—	(8)
Total reorganization items	$ 3	$ 18	$ 6	$ (261)

Provision for expected allowed claims — During the six months ended June 30, 2008, our provision for expected allowed claims consisted primarily of a $62 million credit related to the settlement of claims with the Canadian Debtors.

Gains on asset sales, net of equipment impairments — Represents gains on the sales of the Hillabee and Fremont development project assets for the six months ended June 30, 2008. See Note 4 for further discussion of our sales of Hillabee and Fremont.

12. Commitments and Contingencies

Litigation

We are party to various litigation matters, including regulatory and administrative proceedings arising out of the normal course of business, the more significant of which are summarized below. The ultimate outcome of each of these matters cannot presently be determined, nor can the liability that could potentially result from a negative outcome be reasonably estimated presently for every case. The liability we may ultimately incur with respect to any one of these matters in the event of a negative outcome may be in excess of amounts currently accrued with respect to such matters and, as a result of these matters, may potentially be material to our financial position or results of operations. We review our litigation activities and determine if an unfavorable outcome to us is considered “remote,” “reasonably possible” or “probable” as defined by GAAP. Where we have determined an unfavorable outcome is probable and is reasonably estimable, we have accrued for potential litigation losses. During the pendency of our Chapter 11 cases through the Effective Date, pursuant to automatic stay provisions under the Bankruptcy Code and orders granted by the Canadian Court, all actions to enforce or otherwise effect repayment of liabilities preceding the Petition Date as well as all pending litigation against the U.S. Debtors and the Canadian Debtors generally were stayed. Following the Effective Date, pending actions to enforce or otherwise effect repayment of liabilities preceding the Petition Date, as well as pending litigation against the U.S. Debtors related to such liabilities generally have been permanently enjoined. Any unresolved claims will continue to be subject to the claims reconciliation process under the supervision of the U.S. Bankruptcy Court. However, certain pending litigation related to pre-petition liabilities may proceed in courts other than the U.S. Bankruptcy Court to the extent the parties to such litigation have obtained relief from the permanent injunction. In particular, certain pending actions against us are anticipated to proceed as described below. See Note 11 for information regarding our emergence from our Chapter 11 and our CCAA proceedings. In addition to the Chapter 11 cases and CCAA proceedings (in connection with which certain of the matters described below arose), and the other matters described below, we are involved in various other claims and legal actions, including regulatory and administrative proceedings arising out of the normal course of our business. We do not expect that the outcome of such other claims and legal actions will have a material adverse effect on our financial position or results of operations.

Hawaii Structural Ironworkers Pension Fund v. Calpine, et al. This case resides in the Santa Clara County Superior Court. Defendants in this case are Calpine Corporation, Peter Cartwright, Ann B. Curtis, John Wilson, Kenneth Derr, George Stathakis, Credit Suisse First Boston LLC, Banc of America Securities LLC, Deutsche Bank Securities, Inc. and Goldman Sachs & Co. The Hawaii Structural Ironworkers Pension Trust Fund alleges that the prospectus and registration statement for an April 2002 offering of Calpine Corporation securities contained false or misleading statements regarding: Calpine Corporation’s actual financial results for 2000 and 2001; Calpine Corporation’s projected financial results for 2002; Mr. Cartwright’s alleged agreement not to sell or purchase shares within 90 days of the April 2002 offering; and Calpine Corporation’s alleged involvement in “wash trades.” The action was temporarily stayed during Calpine Corporation’s Chapter 11 filing.

On December 19, 2007, Calpine Corporation entered into an agreement with the Hawaii Structural Ironworkers Pension Trust Fund to allow the action to proceed. Calpine Corporation remains a defendant to the action. The December 19, 2007, agreement provides that the Hawaii Structural Ironworkers Pension Fund waived its right to collect from Calpine Corporation on the claim it had filed in the Chapter 11 cases, or for any settlement with Calpine Corporation, and agreed to seek recovery to satisfy its claim against Calpine Corporation, or for any settlement with Calpine Corporation, solely from insurance coverage available to Calpine Corporation. However, the December 19, 2007, agreement does not address the Hawaii Structural Ironworkers Pension Fund's claims against any of the other defendants. Some or all of the other defendants have asserted or may assert indemnification claims against Calpine Corporation in connection with this action.

On July 1, 2008, a second amended complaint was filed against the same defendants. The second amended complaint repeated the allegations from the first amended complaint and added allegations that the above-described prospectus and registration statement included false or misleading statements related, among other things, to Calpine Corporation's cash balances and cash flow, construction projects and asset sales. The parties completed fact discovery in February 2009 and are conducting expert discovery. No trial date has been set in this action. The parties attended mediation on June 1, 2009, and currently remain in settlement discussions. Any settlement is expected to be covered by insurance.

Pit River Tribe, et al. v. Bureau of Land Management, et al. On June 17, 2002, the Pit River Tribe filed suit against the BLM and other federal agencies in the U.S. District Court for the Eastern District of California seeking to enjoin further exploration, construction and development of the Calpine Fourmile Hill Project in the Glass Mountain and Medicine Lake geothermal areas. Its complaint challenged the validity of the decisions of the BLM and the U.S. Forest Service to permit the development of the proposed project under two geothermal mineral leases previously issued by the BLM. The lawsuit also sought to invalidate the leases. Only declaratory and equitable relief was sought.

The case was temporarily stayed during our Chapter 11 case; however, we and Pit River filed a stipulation to lift the automatic stay. On November 5, 2006, the Ninth Circuit issued a decision granting the plaintiffs relief by holding that the BLM had not complied with the National Environmental Policy Act, and other procedural requirements and, therefore, held that the lease extensions were invalid. The Ninth Circuit remanded the matter back to the U.S. District Court to implement its decision. On December 22, 2008, the U.S. District Court ruled that the lease extension for the two Fourmile Hill leases and the approval to construct a proposed 49.9 MW Fourmile Hill power plant should be remanded to the federal agencies for curative action. The U.S. District Court also required that we notify the BLM and the U.S. Forest Service that we affirm the original plan of utilization for 49.9 MW Fourmile Hill power project by April 1, 2009, or to submit a new plan of utilization for review by a date to be set by the agencies. The Pit Tribe timely appealed the Court's December 22, 2008, order and written briefing is scheduled to be complete in August 2009. On March 31, 2009, in compliance with the Court's December 22, 2008, order, we informed the BLM that we did not want the BLM to perform the curative actions in its environmental impact assessment and other procedural steps based upon the previously proposed 49.9 MW Fourmile Hill power project. Instead, we would likely construct a larger project to be located on both the Fourmile Hill leases and the Telephone Flat leases. We requested the federal agencies prepare a programmatic environmental impact statement for the Medicine Lake and Glass Mountain geothermal areas and determine whether and how geothermal exploration and development should occur in those areas based upon a reasonable foreseeable development scenario which assumes the BLM's previously published resource potential of 480 MW.

In addition, Pit River and other interested parties filed two separate suits in the U.S. District Court for the Eastern District of California seeking to enjoin exploration, construction, and development of the Telephone Flat leases and proposed project at Glass Mountain in May 2004. These two related cases continue to be subject to the discharge injunction as described in the Order confirming the Plan of Reorganization. Similar to above, we are now in communication with the U.S. Department of Justice regarding these two cases; but, the cases remain mostly inactive pending the outcome of the above described Pit River Tribe case.

Appeal of Confirmation Order. Several parties filed appeals in the SDNY Court seeking reconsideration of the Confirmation Order of the U.S. Bankruptcy Court, despite the effectiveness of the Plan of Reorganization. On June 6, 2008, the SDNY Court entered an order denying the appeals, finding that all of the appeals were equitably moot. One of the shareholders (Mr. Felluss) filed a motion for reconsideration, which was denied on June 24, 2008. On July 3, 2008, Mr. Felluss filed a notice of appeal with the Second Circuit. In addition, on August 8, 2008, Mr. Felluss filed a motion with the Second Circuit seeking to stay the expiration of the warrants that had been issued pursuant to the Plan of Reorganization and were scheduled to expire August 25, 2008; the Second Circuit denied the motion on August 27, 2008. The parties then proceeded to brief the merits of Mr. Felluss' appeal. The Second Circuit recently advised the parties that it will schedule oral argument for the week of September 8, 2009.

Other Contingencies

Texas City and Clear Lake Environmental Matters. As part of an internal review of our Texas City and Clear Lake power plants, we determined that these facilities were in violation of the requirements of the Acid Rain Program found in 40 CFR Parts 72-78. These facilities were originally exempt from these provisions because each plant was a qualifying cogeneration facility in operation before November 1990 with qualifying original PPAs in place. However, the PPAs expired in 2002 for Texas City and 1999 for Clear Lake. To remedy the violations, the facilities are required to retire the number of SO_2 emission allowances equal to actual SO_2 emitted since the expiration of the exemption and remit an excess emission fee for each ton of SO_2 emitted during the period of non-compliance. We have recorded estimated excess emission fees totaling $298,000 for Texas City and Clear Lake. We self-reported these violations to the TCEQ and the EPA, and are currently working with both agencies in an effort to resolve these issues. Compliance agreements between each power plant and the TCEQ were executed on September 26, 2008, and limit enforcement by the TCEQ. The EPA does have authority and discretion to issue substantial fines that could be material; however, based on the circumstances and on consideration of recent cases addressed by the agencies involved, we do not believe that the maximum penalty will be assessed or that penalties, if any, resulting from these matters will have a material adverse effect on our business, financial condition or results of operations.

Lyondell Bankruptcy. On January 6, 2009, Lyondell Chemical Co. and certain of its subsidiaries, including Houston Refining LP, filed for protection under Chapter 11 in the U.S. Bankruptcy Court. Channel Energy Center leases its project site from Houston Refining LP and is granted certain easements in, over, under and on the site pursuant to the lease. Channel Energy Center provides power and steam to Houston Refining LP pursuant to a power services agreement and, pursuant to a power plant services agreement, provides clarified water and treated water to Houston Refining LP. Channel Energy Center is provided with raw water, refinery gas and certain other power plant services by Houston Refining LP.

The Lyondell debtors may exercise their right under the Bankruptcy Code to reject the lease, the power services agreement and/or the power plant services agreement. The potential damages to us if any or all of these agreements is rejected are uncertain and would represent an unsecured bankruptcy claim with Lyondell. To the extent that any such damages would be recoverable under the laws of the State of Texas, the governing law under the agreements, they would be treated as an unsecured claim against the Lyondell debtors in bankruptcy. The percentage of recovery on unsecured claims in the Lyondell bankruptcy is unknown at this time, but is expected to be low.

We continue to monitor this matter closely and will seek vigorously to protect our rights under our various agreements with the Lyondell debtors.

Communications with the SEC. As disclosed in our 2008 Form 10-K, we were contacted by and had meetings with the staff of the SEC regarding our financial statements and internal control over financial reporting, as well as those of CalGen, a wholly owned subsidiary. We cooperated with the SEC Staff and provided information in response to the Staff's request. On June 10, 2009, we received a confirmation letter from the SEC staff informing us that the SEC had completed its investigation and did not recommend any enforcement action. Accordingly, we consider this matter closed.

13. Segment Information

We are an independent wholesale power generation company engaged in the ownership and operation of natural gas-fired and geothermal power plants in North America. We assess our business primarily on a regional basis due to the impact on our financial performance of the differing characteristics of these regions, particularly with respect to competition, regulation and other factors impacting supply and demand. Accordingly, our reportable segments are West (including geothermal), Texas, Southeast and North (including Canada). We continue to evaluate the optimal manner in which we assess our performance including our segments and future changes may result.

Commodity Margin includes our power and steam revenues, capacity revenue, REC revenue and expense, transmission revenue and expenses, fuel and purchased energy expense, and cash settlements from our marketing, hedging and optimization activities that are included in mark-to-market activity, but excludes the unrealized portion of our mark-to-market activity and other revenue. Commodity Margin is a key operational measure reviewed by our chief operating decision maker to assess the performance of our segments.

During the first quarter of 2009, we began assessing the performance of our regional segments to include the allocation, based upon MWh, of revenues and expenses from our fuel management, TMG, certain non-region specific natural gas marketing and optimization and other corporate activities to our operating segments that were formerly non-allocated and previously reported as our "Other" segment. Additionally, we have modified our definition of Commodity Margin to include cash settlements from our marketing, hedging and optimization activities that were previously included in mark-to-market activity. Our 2008 segment information has been reclassified to conform to the current period presentation. Financial data for our segments were as follows (in millions):

	Three Months Ended June 30, 2009					
	West	Texas	Southeast	North	Consolidation and Elimination	Total
Revenues from external customers	$ 789	$ 371	$ 178	$ 133	$ —	$ 1,471
Intersegment revenues	9	20	21	2	(52)	—
Total operating revenues	$ 798	$ 391	$ 199	$ 135	$ (52)	$ 1,471
Commodity Margin	$ 304	$ 196	$ 80	$ 70	$ —	$ 650
Add: Mark-to-market commodity activity, net and other revenue(1)	57	(140)	(25)	14	(9)	(103)
Less:						
Plant operating expense	100	50	35	23	2	210
Depreciation and amortization expense	52	31	17	15	(2)	113
Other cost of revenue(2)	12	2	1	7	(4)	18
Gross profit (loss)	197	(27)	2	39	(5)	206
Other operating expenses	2	21	8	—	—	31
Income (loss) from operations	195	(48)	(6)	39	(5)	175
Interest expense, net of interest income						203
Debt extinguishment costs and other (income) expense, net						33
Loss before reorganization items and income taxes						(61)
Reorganization items						3
Loss before income taxes						$ (64)

	Three Months Ended June 30, 2008					
	West	Texas	Southeast	North	Consolidation and Elimination	Total
Revenues from external customers	$ 1,165	$ 1,115	$ 417	$ 131	$ —	$ 2,828
Intersegment revenues	15	79	60	7	(161)	—
Total operating revenues	$ 1,180	$ 1,194	$ 477	$ 138	$ (161)	$ 2,828
Commodity Margin	$ 315	$ 215	$ 78	$ 67	$ —	$ 675
Add: Mark-to-market commodity activity, net and other revenue(1)	64	51	16	22	(8)	145
Less:						
Plant operating expense	101	52	23	24	6	206
Depreciation and amortization expense	44	33	19	13	(1)	108
Other cost of revenue(2)	18	6	9	7	(10)	30
Gross profit	216	175	43	45	(3)	476
Other operating expenses	10	22	6	5	—	43
Income from operations	206	153	37	40	(3)	433
Interest expense, net of interest income						192
Debt extinguishment costs and other (income) expense, net						1
Income before reorganization items and income taxes						240
Reorganization items						18
Income before income taxes						$ 222

	Six Months Ended June 30, 2009					
	West	Texas	Southeast	North	Consolidation and Elimination	Total
Revenues from external customers	$ 1,677	$ 856	$ 351	$ 264	$ —	$ 3,148
Intersegment revenues	17	53	55	13	(138)	—
Total operating revenues	$ 1,694	$ 909	$ 406	$ 277	$ (138)	$ 3,148
Commodity Margin	$ 601	$ 318	$ 141	$ 119	$ —	$ 1,179
Add: Mark-to-market commodity activity, net and other revenue(1)	79	(50)	6	16	(23)	28
Less:						
Plant operating expense	227	128	67	43	(7)	458
Depreciation and amortization expense	101	61	33	31	(4)	222
Other cost of revenue(2)	27	5	4	13	(10)	39
Gross profit	325	74	43	48	(2)	488
Other operating expenses	13	37	15	(3)	—	62
Income from operations	312	37	28	51	(2)	426
Interest expense, net of interest income						407
Debt extinguishment costs and other (income) expense, net						37
Loss before reorganization items and income taxes						(18)
Reorganization items						6
Loss before income taxes						$ (24)

	Six Months Ended June 30, 2008					
	West	Texas	Southeast	North	Consolidation and Elimination	Total
Revenues from external customers	$ 2,137	$ 1,690	$ 679	$ 273	$ —	$ 4,779
Intersegment revenues	25	120	94	12	(251)	—
Total operating revenues	$ 2,162	$ 1,810	$ 773	$ 285	$ (251)	$ 4,779
Commodity Margin	$ 593	$ 354	$ 113	$ 128	$ —	$ 1,188
Add: Mark-to-market commodity activity, net and other revenue(1)	15	(74)	3	45	(11)	(22)
Less:						
Plant operating expense	213	122	53	50	—	438
Depreciation and amortization expense	95	63	38	25	(2)	219
Other cost of revenue(2)	35	6	18	13	(10)	62
Gross profit	265	89	7	85	1	447
Other operating expenses	33	40	13	10	—	96
Income (loss) from operations	232	49	(6)	75	1	351
Interest expense, net of interest income						598
Debt extinguishment costs and other (income) expense, net						11
Loss before reorganization items and income taxes						(258)
Reorganization items						(261)
Income before income taxes						$ 3

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(1) Mark-to-market commodity activity represents the unrealized portion of our mark-to-market activity, net, as well as a non-cash gain from amortization of prepaid power sales agreements included in operating revenues and fuel and purchased energy expense on our Consolidated Condensed Statements of Operations.

(2) Excludes $2 million and $4 million of REC expense for the three and six months ended June 30, 2009, respectively, and nil for both the three and six months ended June 30, 2008, which is included as a component of Commodity Margin.

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

Introduction and Overview

We are an independent wholesale power generation company engaged in the ownership and operation of natural gas-fired and geothermal power plants in North America. We have a significant presence in the major competitive power markets in the U.S., including California and Texas. We sell wholesale power, steam, capacity, renewable energy credits and ancillary services to our customers, including industrial companies, retail power providers, utilities, municipalities, independent electric system operators, marketers and others. We engage in the purchase of natural gas as fuel for our power plants and in related natural gas transportation and storage transactions, and in the purchase of electric transmission rights to deliver power to our customers. We also enter into natural gas and power, commodity and financial derivative transactions to economically hedge our business risks and optimize our portfolio of power plants. We seek to grow our business through selective power plant development, construction and acquisition as well as through expansion or upgrades of our existing power plants, in each case, based primarily on whether we expect to achieve an attractive return on invested capital.

We are the largest publicly traded, independent wholesale power company in the U.S. measured by power produced in the U.S. in 2008. Our portfolio, including partnership interests, consists of 76 operating power plants, with an aggregate generation capacity of approximately 24,187 MW and our net interest in two additional power plants totaling nearly 1,000 MW under construction or in advanced development. Our portfolio is comprised of two types of power generation technologies: natural gas-fired combustion turbines (primarily combined-cycle) and renewable geothermal conventional steam turbines. We generate 4,080 MW of baseload capacity from our Geysers Assets and cogeneration power plants (natural gas-fired power plants that produce and sell both power and steam), 15,057 MW of intermediate load capacity from our combined-cycle combustion turbines and 5,050 MW of peaking capacity from our simple-cycle combustion turbines and duct-fired capability.

We assess our business on a regional basis due to the impact on our financial performance of the differing characteristics of these regions, particularly with respect to competition, regulation and other factors impacting supply and demand. Our reportable segments are West (including geothermal), Texas, Southeast and North (including Canada). In these segments we have an aggregate generation capacity of 7,246 MW in the West, 7,487 MW in Texas, 6,104 MW in the Southeast and 3,350 MW in the North (including Canada). Our Geysers Assets, located in northern California and included in our West segment, produce approximately 725 MW from 15 operating power plants and represent the largest geothermal power generation portfolio in the U.S.

We remain focused on increasing our earnings and generating cash flows sufficient to maintain adequate levels of liquidity to service our debt and to fund our operations. We will continue to pursue opportunities to improve our fleet performance and reduce operating costs. In order to manage our various physical assets and contractual obligations, we will continue to execute commodity hedging agreements within the guidelines of our commodity risk policy.

During the second quarter of 2009, we completed the $1.0 billion CCFC Refinancing, pursuant to which our subsidiaries CCFC and CCFC Finance issued $1.0 billion aggregate principal amount of 8.0% Senior Secured Notes due 2016 in a private placement. The net proceeds of $939 million received from the issuance of the notes, together with CCFC cash on hand of $271 million, were used to:

- repay the $364 million outstanding CCFC Term Loans, maturing in August 2009, on May 19, 2009;
- redeem the $415 million outstanding principal amount of CCFC Old Notes, maturing in August 2011, on June 18, 2009;
- redeem the $300 million outstanding CCFCP Preferred Shares, maturing in October 2011, on or before July 1, 2009; and
- in each case, pay any interest, prepayment penalties and other amounts due through the date of such repayment or redemption.

As a result of the CCFC Refinancing transactions, we were able to extend the maturities of approximately $1.0 billon of debt by several years, at the same time converting it from a floating to a fixed interest rate and lowering our interest rate on such debt to 8.0% from a current weighted average interest rate of approximately 9.4% with respect to the CCFC Term Loans, CCFC Old Notes and CCFCP Preferred Shares.

Legislative and Regulatory Update

Ongoing state, regional and federal initiatives to implement new environmental and other governmental regulations are expected to have a significant impact on the power generation industry. We are actively participating in these debates at the federal, regional and state levels concerning potential environmental regulation. For a further discussion of the environmental and other governmental regulations that affect us, please see "—Governmental and Regulatory Matters" in Part I, Item 1. of our 2008 Form 10-K. Below is a short discussion of the recent developments as they pertain to our business.

Climate Change

On June 26, 2009, the U.S. House of Representatives passed "The American Clean Energy and Security Act of 2009," a climate change and clean energy bill. The legislation includes, among other provisions:

- An economy-wide carbon cap-and-trade program that:

  i. sets reduction targets for carbon emissions from capped sources in several sectors of the economy, including the electricity sector, starting at a 3% reduction from 2005 levels by 2012, increasing to 80% by 2050,
  ii. starts in 2012 for the electricity sector and establishes the point of regulation at the power plant,
  iii. distributes 85% of emissions allowances for free, with 35.85% going to the electricity sector, including 1.5% to eligible generation facilities with qualifying long-term power and steam sales contracts,
  iv. requires an auction of the remaining 15% of emissions allowances with the proceeds of such auctions distributed to low- and moderate-income families, and
  v. delegates authority to FERC to regulate the cash market in emissions allowances and offsets and to the CFTC to regulate the associated derivatives market.

- A federal energy efficiency and renewable electricity standard which requires retail electricity suppliers to meet the needs of a specific percentage of their load from renewable energy resources and electricity savings

If this bill were to become law, we would have the obligation to obtain emissions allowances for the operation of our fossil-fuel power plants. While we expect the costs to acquire allowances to be a factor that will impact market price, there can be no assurance that market price will fully reflect these costs. With respect to our existing long-term steam and power contracts under which we would not be able to recover costs to acquire allowances from our customers, the bill allocates a pool of free allowances to generators with qualifying contracts to mitigate such costs. However, there can be no assurance there will be a sufficient number of free allowances in the pool to fully cover emissions related to generation under such contracts.

The Senate has commenced hearings on the climate change issue but has not yet introduced any legislation. Although we cannot predict the effect and ultimate content of final climate change legislation and regulations, if any, on our business, we continue to monitor and actively participate in the process where we anticipate an impact on our business.

Texas

Texas bill HB 2782, introduced and pending in the House State Affairs Committee earlier this year, could have required the divestiture of certain of our assets in ERCOT's Houston zone. This bill failed to reach final passage and no divestiture will be required. Generally, no legislation was passed that will have a material impact on our Texas operations.

The Sunset review process, implemented by the Texas Legislature in 1977, is the regular assessment of the need for a state agency to exist and to consider new and innovative changes to improve each agency's operations and activities. The Sunset process works by setting a date on which an agency will be abolished unless legislation is passed to continue its functions. The Sunset review process is scheduled to begin this summer for the PUCT, TCEQ and ERCOT. We will monitor the Sunset review process of these entities and will seek to participate in these processes where we anticipate an impact on our business.

Federal Regulation of GHG under Existing Law

As discussed in the 2008 Form 10-K, in 2007 the U.S. Supreme Court ruled in *Commonwealth of Massachusetts, et al. v. U.S. Environmental Protection Agency*, that the EPA has the authority to regulate GHG issues under language included in the CAA. On April 24, 2009, the EPA released its proposed finding that GHG emissions endanger the public health and welfare of current and future generations. Should the EPA finalize the finding, it may begin developing rules to regulate GHG emissions under the CAA. We are uncertain of the timing of the process for development of potential GHG emissions regulations or what form such regulations may take; accordingly, it is not clear what impact any regulations will have on us.

Stimulus Bill

The American Recovery and Reinvestment Act of 2009, also referred to as the Stimulus Bill, was signed into law on February 17, 2009. The Stimulus Bill includes approximately $787.0 billion in federal tax cuts, expansion of unemployment benefits and other social welfare provisions, and increased domestic spending for education, healthcare and infrastructure, including the energy sector. Approximately $43.0 billion will be available for loans and investments into green energy technology and a number of other renewable energy incentives that can impact our growth and development, particularly our geothermal assets. Specifically, the Stimulus Bill:

- extends the placed-in-service deadline through 2013 for geothermal projects to qualify for "production tax credits";
- allows geothermal developers to elect to receive a 30% "investment tax credit" in lieu of production tax credits with respect to certain "qualified property" placed in service during 2009 or 2010 (or, in certain cases, after 2010), or a cash grant in lieu of investment tax credits or production tax credits with respect to such qualified property (subject to satisfying certain procedural and other requirements mandated by recently-issued Department of Treasury guidance);
- designates $6.0 billion in funds to serve as a loss reserve and source of funding for a federal loan guarantee program anticipated to backstop renewable energy project financing; and
- designates $400 million in funds for the Department of Energy's Geothermal Technologies Program.

We anticipate that our planned investment in our current geothermal power plants, including the re-powering of many of our existing power plants, along with expansion efforts that may include new geothermal plant development, could all benefit from the additional funds and incentives provided by the Stimulus Bill. Applications for grants funded by the Stimulus Bill and implemented through the Department of Energy were due July 22, 2009, and July 30, 2009, respectively, and we applied for ten individual geothermal technology grants.

Geothermal Operations

In 2009, as part of a joint private and federally funded geothermal technology research project, a company unrelated to us commenced deepening an existing geothermal well on a property neighboring our Geysers Assets and reportedly is attempting to drill into the hot, low or non-permeable base rock that underlies the existing geothermal steam reservoir at The Geysers to engineer or create a "multilayered heat extraction system" below the reservoir by injecting water under very high pressure, fracturing the rock. This process has spawned public and political concern regarding increased seismicity risk. As a consequence, in July 2009, the Department of Energy temporarily halted funding of its portion of that project pending further seismicity studies. Although our geothermal operations do not include attempts to engineer or create new reservoirs from hot, non-permeable rock, the public concern regarding induced seismicity could delay or otherwise adversely impact our Department of Energy grant applications. In addition, it is possible that government agencies will seek to more stringently regulate the exploration, development, and operation of geothermal facilities, including our Geysers Assets, in order to mitigate induced seismicity resulting from geothermal operations.

Liquidity and Capital Resources

Our business is capital intensive. Our ability to successfully implement our strategy is dependent on the continued availability of capital on attractive terms. In addition, our ability to successfully operate our business and to meet certain near-term debt repayment obligations is dependent on maintaining sufficient liquidity.

As of June 30, 2009, we had approximately $1.5 billion in cash and cash equivalents and $534 million of restricted cash. Included in our cash and cash equivalents is $725 million borrowed on October 2, 2008 under our Exit Credit Facility revolver. Our borrowing under the Exit Credit Facility revolver was a proactive financial decision to increase our cash position and reduce the risk of nonperformance from institutions that hold a commitment in our Exit Credit Facility revolver during a period of uncertainty in the capital markets, and was invested in money market funds, which are mainly invested in U.S. Treasury securities or other obligations issued or guaranteed by the U.S. government, its agencies or instrumentalities. Our remaining availability under our Exit Credit Facility revolver as of June 30, 2009, is approximately $55 million for future letters of credit or cash borrowings. Our decision to repay or hold all or part of the cash from our $725 million draw under our Exit Credit Facility revolver, or to use all or part of that borrowing to pay down other debt with will be determined based upon our anticipated future liquidity needs and our expectations regarding future credit markets.

Volatility in the financial markets through 2008 and into 2009, including the failure or merger of certain financial institutions and continued uncertainty surrounding many others continues to constrict access to capital and credit markets in the U.S. and worldwide, including within our industry, for us and for our counterparties. We are unable to predict the length or severity of the economic downturn; but expect these conditions will persist during 2009 and possibly longer. As a result, we and the industry have experienced increased credit and liquidity risk over the past several months. Even if we are not impacted directly, we could be impacted indirectly in the event our counterparties are unable to perform under their contractual obligations with us. We actively monitor our exposure to our counterparties including their credit status.

We believe that we have adequate resources from a combination of cash and cash equivalents on hand and cash expected to be generated from future operations to continue to meet our obligations as they become due. Despite the current volatility in the financial markets and relative illiquidity, we have been able to close two significant financings during 2009 as further described below. If investor and creditor markets improve and more confidence returns, we may decide to refinance additional portions of our nearer term maturities or more costly debt. We are also seeking to amend certain terms of our Exit Credit Facility to allow us the option to buy back debt at a discount via auction and certain other amendments that permit additional flexibility to enhance the management of our capital structure.

CCFC Refinancing — On May 19, 2009, CCFC and CCFC Finance issued $1.0 billion in aggregate principal amount of CCFC New Notes in a private placement. Interest on the CCFC New Notes accrues at the rate of 8.0% per annum and is payable semi-annually in arrears on each June 1 and December 1, commencing on December 1, 2009. The CCFC New Notes which mature on June 1, 2016, are guaranteed by two of CCFC's subsidiaries. The CCFC New Notes and the related guarantees are secured, subject to certain exceptions and permitted liens, by all real and personal property of CCFC and CCFC's material subsidiaries (including the CCFC Guarantors), consisting primarily of six natural gas power plants as well as the equity interests in CCFC and the CCFC Guarantors. The net proceeds received of $939 million, together with CCFC cash on hand of $271 million, were used to:

- repay the $364 million outstanding under the CCFC Term Loans on May 19, 2009;
- redeem the $415 million outstanding principal amount of CCFC Old Notes on June 18, 2009;
- distribute $327 million to CCFC's indirect parent, CCFCP, which was used by CCFCP to redeem its $300 million CCFCP Preferred Shares on or before July 1, 2009; and
- in each case, pay any interest, prepayment penalties and other amounts due through the date of such repayment or redemption.

In connection with the CCFC Refinancing, we recorded $33 million in debt extinguishment costs for the three and six months ended June 30, 2009, from the write-off of unamortized deferred financing costs and unamortized debt discount of $7 million and prepayment penalties of $24 million related to the CCFC Old Notes, and $2 million related to the CCFCP

Preferred Shares redeemed on or before June 30, 2009. These items are recorded in debt extinguishment costs on our Consolidated Condensed Statements of Operations for the three and six months ended June 30, 2009. We also recorded approximately $21 million in new deferred financing costs on our Consolidated Condensed Balance Sheet at June 30, 2009.

As a result of the CCFC Refinancing transactions, we were able to extend the maturities of approximately $1.0 billon of debt by several years, at the same time converting it from a floating to a fixed interest rate and lowering our interest rate on such debt to 8.0% from a current weighted average interest rate of approximately 9.4% with respect to the CCFC Term Loans, CCFC Old Notes and CCFCP Preferred Shares.

We offered early redemption prior to July 1, 2009, to each holder of the CCFCP Preferred Shares. As of June 30, 2009, $36 million of the CCFCP Preferred Shares had been redeemed. The remaining $264 million is reported as debt, current portion on our Consolidated Condensed Balance Sheet. This balance was redeemed on July 1, 2009, and we recorded an additional $15 million in debt extinguishment costs related to prepayment penalties and the write-off of unamortized deferred financing costs on July 1, 2009.

Concurrent with the CCFC Refinancing, we replaced various intercompany agreements with our CCFC subsidiaries for the related sales and purchases of power, natural gas and the operation and maintenance of our CCFC power plants, which did not materially impact our results of operations, financial condition or cash flows on a consolidated basis.

Deer Park Financing — On January 21, 2009, Deer Park, our indirect wholly owned subsidiary, closed on $156 million of senior secured credit facilities, which include a $150 million term facility and a $6 million letter of credit facility. Proceeds received were used to settle an existing commodity contract of approximately $79 million, pay financing and legal fees of approximately $8 million and fund approximately $22 million in restricted cash. The remainder was distributed to Calpine Corporation for general corporate purposes. The senior term loan facility matures on January 21, 2012, and bears interest of LIBOR plus 3.5% or base rate plus 2.5% at Deer Park's option.

Liquidity Sensitivity — Significant changes in commodity prices and Market Heat Rates can have an impact on our liquidity as we use margin deposits, cash prepayments and letters of credit as credit support (collateral) with and from our counterparties for commodity procurement and risk management activities. Utilizing our portfolio of transactions subject to collateral exposure, we estimate that, as of July 10, 2009, an increase of $1/MMBtu in natural gas prices would result in an increase of collateral required of approximately $160 million. If natural gas prices decreased by $1/MMBtu, we estimate that our collateral requirements would decrease by approximately $136 million. Changes in Market Heat Rates also affect our liquidity. For example, as demand increases, less efficient generation is dispatched, which increases the Market Heat Rate and results in increased collateral requirements. Based upon historical relationships of natural gas and Market Heat Rate movements for our portfolio of assets, we derived a statistical analysis that indicates that a change of $1/MMBtu in natural gas is comparable to a Market Heat Rate change of 170 Btu/KWh. We estimate that, as of July 10, 2009, an increase of 170 Btu/KWh in the Market Heat Rate would result in an increase in collateral required of approximately $15 million. If Market Heat Rates were to fall at a similar rate, we estimate that our collateral required would decrease by $17 million. These amounts are not necessarily indicative of the actual amounts that could be required, which may be higher or lower than the amounts estimated above.

In order to reduce the cash collateral and letters of credit that we would otherwise be required to provide to our counterparties, we have granted additional liens on the assets currently subject to liens under the Exit Credit Facility to collateralize our obligations under certain of our power and natural gas agreements that qualify as "eligible commodity hedge agreements" under the Exit Credit Facility, and certain of our interest rate swap agreements. The counterparties under such agreements will share the benefits of the collateral subject to such liens ratably with the lenders under the Exit Credit Facility. We have increased our usage of these additional liens during the second quarter of 2009 in order to help manage cash collateral that would otherwise be required. See Note 8 of the Notes to Consolidated Condensed Financial Statements for further information on our margin deposits and collateral used for commodity procurement and risk management activities.

To provide for increased liquidity in periods of rising commodity prices, we have the Commodity Collateral Revolver that increases our liquidity available to collateralize obligations to counterparties under eligible commodity hedge agreements during periods of increasing natural gas prices. The Commodity Collateral Revolver, which matures July 8, 2010, provides up to a total maximum availability of $300 million contingent on mark-to-market exposure amounts under certain reference transactions. We received an initial advance of $100 million in 2008; however, it is unlikely that any additional amounts under this facility will be available as natural gas prices are not expected to exceed stated thresholds in the near future. Through June 30, 2009, the Knock-in Facility had provided additional letter of credit availability. The Knock-in Facility matured on June 30, 2009, and is therefore no longer a source of liquidity for us. We previously had approximately $44 million in letters of credit outstanding under the Knock-in Facility which terminated in June 2009 and were replaced with cash collateral of $30 million. See "— Letter of Credit Facilities" below.

We could potentially face downward pressure on our Commodity Margin as a result of the current economic recession. The impacts would be highly dependent on the severity and duration of the economic downturn. During pronounced recessionary periods, there can be a decrease in power demand primarily driven by decreased usage by the industrial and manufacturing sectors. This "softening" of demand typically results in more demand satisfied by baseload and intermediate units using lower variable cost fuel sources such as coal and nuclear fuel, and less demand served by higher variable cost units such as natural gas-fired peaking power plants. Additionally, a recessionary environment can result in lower natural gas pricing which may adversely impact our Commodity Margin as our cost of production advantage relative to less efficient natural gas-fired generation is diminished on an absolute basis. However, with our combined forward power sales and natural gas purchases, we believe that we have economically hedged a substantial portion of our Commodity Margin for the remainder of 2009. Additionally, we have economically hedged much of 2010 and therefore do not expect further declines in natural gas prices to result in a material detriment to our results of operations in the near term.

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 should financial market and commodity price volatility persist for a significant period of time. Our ability to generate sufficient cash is dependent upon, among other things:

- improving the profitability of our operations;
- continued compliance with the covenants under our Exit Credit Facility and other existing financing obligations;
- stabilizing and increasing future contractual cash flows; and
- our significant counterparties performing under their contracts with us.

Letter of Credit Facilities — The table below represents amounts outstanding under our letter of credit facilities as of June 30, 2009 (in millions):

		2009
Exit Credit Facility	$	220
Calpine Development Holdings, Inc.		148
Various project financing facilities		98
Total	$	466

Cash Management — We manage our cash in accordance with our intercompany cash management system subject to the requirements of the Exit Credit Facility and requirements under certain of our project debt and lease agreements or by regulatory agencies. Our cash and cash equivalents as well as our restricted cash balances generally exceed FDIC insured limits or are invested in money market accounts with investment banks that are not FDIC insured. We place our cash, cash equivalents and restricted cash in what we believe to be credit-worthy financial institutions and most of our money market accounts invest in U.S. Treasury securities or other obligations issued or guaranteed by the U.S. government, its agencies or instrumentalities.

We do not expect to pay any cash dividends on our common stock for the foreseeable future because we are currently prohibited under the Exit Credit Facility and certain of our other debt agreements from paying cash dividends. Future cash dividends, if any, will be at the discretion of our Board of Directors and will depend upon, among other things, our future operations and earnings, capital requirements, general financial condition, contractual and financing restrictions and such other factors as our Board of Directors may deem relevant.

NOLs — We have significant NOLs that will provide future tax deductions if we generate sufficient taxable income during the carryover periods. Our federal and state income tax reporting group is comprised primarily of two groups, CCFC and its subsidiaries, which we refer to as the CCFC group and Calpine Corporation and its subsidiaries other than CCFC, which we refer to as the Calpine group. As of December 31, 2008, our consolidated federal NOLs totaled approximately $7.5 billion, which consists of approximately $7.1 billion from our Calpine group and approximately $396 million from our CCFC group. We expect to generate approximately $60 million to $80 million in federal NOLs in 2009. In addition, we have approximately $1.0 billion in foreign NOLs and $4.4 billion in state NOLs. Our Calpine group has recorded a valuation allowance against the deferred taxes related to most of their NOLs as we determined it is more likely than not, that they will expire unutilized. Approximately $5.6 billion of our NOLs have annual limitations under Section 382 of the IRC. Amounts subject to limitations, but not used, can be carried forward to succeeding years.

Optimization of Existing Assets — We continue to review development opportunities, which were put on hold during the pendency of our Chapter 11 cases, to determine whether future actions are appropriate and we may pursue new opportunities that arise, particularly if power contracts and financing are available and attractive returns are expected. Currently, we have one project, Russell City Energy Center, in advanced development and our OMEC project remains under construction.

The Russell City Energy Center is currently contracted to deliver its full output to PG&E under a PPA which was executed in December 2006 and approved by the CPUC in January 2007. The PPA was amended in 2008 and was approved by the CPUC on April 16, 2009. All permits for the projects have been issued and approved with the exception of an air permit now pending before the local air quality board. Completion of the Russell City Energy Center is dependent upon obtaining the necessary permits, regulatory approvals, construction contracts and construction funding under project financing facilities. We do not expect the costs to complete the Russell City Energy Center to be material to us on a consolidated basis. Upon completion, this project would bring on line approximately 362 MW of net interest baseload capacity (390 MW with peaking capacity) representing our 65% share.

We hold all of the equity interest in one unconsolidated project under construction at June 30, 2009, OMEC, which is expected to achieve commercial operations in the fall of 2009. The completion of OMEC will bring on line approximately 596 MW of net interest baseload (with peaking) capacity. We also own a 50% equity interest in the Greenfield Energy Centre, which achieved commercial operations on October 17, 2008. Our net interest baseload (with peaking) capacity increased as a result of Greenfield Energy Centre by approximately 503 MW representing our 50% share.

Cash Flow Activities — The following table summarizes our cash flow activities for the six months ended June 30, 2009 and 2008 (in millions):

	2009	2008
Beginning cash and cash equivalents	$ 1,657	$ 1,915
Net cash provided by (used in):		
Operating activities	(36)	(586)
Investing activities	(137)	469
Financing activities	(2)	(1,428)
Net decrease in cash and cash equivalents	(175)	(1,545)
Ending cash and cash equivalents	$ 1,482	$ 370

Net Cash Used In Operating Activities

Cash flows used in operating activities for the six months ended June 30, 2009, improved to net outflows of $36 million compared to net outflows of $586 million for the same period in 2008. Our improvement in cash flows used in operating activities was primarily due to:

- Decrease in interest paid — Cash paid for interest decreased by $236 million, to $398 million for the six months ended June 30, 2009, as compared to $634 million for the same period in 2008, primarily due to the repayment of the Second Priority Debt, the one time payments of post-petition interest of $135 million related to pre-emergence debt and $27 million in post-petition interest paid by our Canadian subsidiaries as a result of our emergence from Chapter 11 on January 31, 2008 and, to a lesser extent, lower interest rates for the comparable period in 2009.
- Decrease in working capital — Working capital employed decreased by approximately $333 million for the 2009 period compared to the 2008 period, after adjusting for debt related balances and assets held for sale which did not impact cash provided by operating activities. The decrease was primarily due to reductions in margin deposits partially offset by increases in net current derivative assets.
- Decrease in reorganization costs — Cash payments for reorganization items decreased by $103 million.

Our improvements in net cash flows used in operating activities were partially offset by the following:

- Decrease in gross profit — Gross profit, excluding unrealized changes in mark-to-market activity and depreication and amortization expense, decreased by $18 million in the six months ended June 30, 2009, as compared to the same period in 2008. This was primarily attributable to lower Commodity Margin as a result of lower natural gas prices and lower Market Heat Rates which was partially offset by the positive impact of our heding activities and higher Market Heat Rates in the Southeast.
- Increase in debt extinguishment costs — Cash payments for debt extinguishment costs in the 2009 period were $26 million related to the CCFC Refinancing, compared to cash payments of $6 million related to the refinancing of Blue Spruce and Metcalf for the comparable period in 2008.
- Decrease in cash received for tax refunds — Cash received for tax refunds was approximately $18 million for the six months ended June 30, 2009, compared to approximately $77 million for the same period in 2008.

Net Cash Provided By (Used In) Investing Activities

Cash flows used in investing activities for the six months ended June 30, 2009, were $137 million compared to cash flows provided by investing activities of $469 million for the six months ended June 30, 2008. The difference was primarily due to the 2008 cash effects of:

- Sales of power plants, turbines and investments — We had no significant asset sales in 2009 compared to $398 million of cash received from the sales of the Fremont and Hillabee development projects in 2008.
- Reconsolidation of our Canadian Debtors and other foreign entities — In 2008, we had a favorable cash effect of $64 million from the reconsolidation of our Canadian Debtors and other foreign entities.
- Return of investment from unconsolidated investment — In the six months ended June 30, 2009 we received a return of investment of nil compared to $24 million for the six months ended June 30, 2008.
- Increased restricted cash requirements — Restricted cash increased $31 million in 2009, compared to a $56 million decrease in 2008.

Net Cash Used In Financing Activities

Because of our emergence from Chapter 11 during the first quarter of 2008, our financing activities are not comparable. Cash flows used in financing activities for the six months ended June 30, 2009, resulted in outflows of $2 million compared to outflows of $1.4 billion for the same period in 2008. Our significant 2009 and 2008 financing transactions are described below:

- During the 2009 period, we had net borrowings of approximately $1.0 billion from the issuance of the CCFC New Notes and from the refinancing of Deer Park, we repaid approximately $779 million of CCFC Old Notes and CCFC Term Loans and $36 million of CCFC Preferred Shares. We also made scheduled repayments of approximately $30 million under the Exit Credit Facility and $152 million on capital lease obligations, other project debt and notes payable.
- During the 2008 period, we borrowed approximately $3.5 billion under the Exit Facilities and used that borrowing and cash on hand to repay approximately $3.7 billion of the Second Priority Debt, $555 million on the Senior Secured Revolver and the $300 million Bridge Facility under the Exit Facilities, and incurred financing costs of $187 million. In addition, we received proceeds of $355 million from the Metcalf and Blue Spruce refinancings and repaid $463 million of other project debt, capital leases and notes payable.

Special Purpose Subsidiaries — Pursuant to applicable transaction agreements, we have established certain of our entities separate from Calpine and our other subsidiaries. In accordance with applicable accounting standards, we consolidate these entities. As of the date of filing this Report, these entities included: Rocky Mountain Energy Center, LLC, Riverside Energy Center, LLC, Calpine Riverside Holdings, LLC, PCF, PCF III, GEC Holdings, LLC, Gilroy Energy Center, LLC, Creed Energy Center, LLC, Goose Haven Energy Center, LLC, Calpine Gilroy Cogen, L.P., Calpine Gilroy 1, Inc., Calpine King City Cogen, LLC, Calpine Securities Company, L.P. (a parent company of Calpine King City Cogen, LLC), Calpine King City, LLC (an indirect parent company of Calpine Securities Company, L.P.), CCFCP, and Russell City Energy Company, LLC.

Results of Operations for the Three Months Ended June 30, 2009 and 2008

Below are the results of operations for the three months ended June 30, 2009, as compared to the same period in 2008 (in millions, except for percentages and operating performance metrics). We have modified our presentation of commodity revenue and commodity expense to include cash settlements from our marketing, hedging and optimization activities that were previously included in mark-to-market activity. Our 2008 commodity revenue and expense information has been reclassified to conform to the current period presentation. In the "$ Change" and ''% Change" columns below, increases in revenue/income or decreases in expense (favorable variances) are shown without brackets while decreases in revenue/income or increases in expense (unfavorable variances) are shown with brackets.

	2009	2008	$ Change	% Change
Operating revenues:				
Commodity revenue	$ 1,470	$ 2,844	$ (1,374)	(48) %
Mark-to-market activity(1)	(4)	(28)	24	86
Other revenue	5	12	(7)	(58)
Operating revenues	1,471	2,828	(1,357)	(48)
Cost of revenue:				
Fuel and purchased energy expense:				
Commodity expense	818	2,169	1,351	62
Mark-to-market activity(1)	104	(161)	(265)	#
Fuel and purchased energy expense	922	2,008	1,086	54
Plant operating expense	210	206	(4)	(2)
Depreciation and amortization expense	113	108	(5)	(5)
Other cost of revenue(2)	20	30	10	33
Total cost of revenue	1,265	2,352	1,087	46
Gross profit	206	476	(270)	(57)
Sales, general and other administrative expense	48	48	—	—
Income from unconsolidated investments in power plants	(23)	(16)	7	44
Other operating expense	6	11	5	45
Income from operations	175	433	(258)	(60)
Interest expense	207	206	(1)	—
Interest (income)	(4)	(14)	(10)	(71)
Debt extinguishment costs	33	6	(27)	#
Other (income) expense, net	—	(5)	(5)	#
Income (loss) before reorganization items and income taxes	(61)	240	(301)	#
Reorganization items	3	18	15	83
Income (loss) before income taxes	(64)	222	(286)	#
Income tax expense	15	25	10	40
Net income (loss)	(79)	197	(276)	#
Add: Net loss attributable to the noncontrolling interest	1	—	1	—
Net income (loss) attributable to Calpine	$ (78)	$ 197	$ (275)	#

Operating Performance Metrics:	2009	2008	Change	% Change
MWh generated (in thousands)(3)	19,399	21,211	(1,812)	(9) %
Average availability	90.8%	89.9%	0.9	1
Average total MW in operation	23,423	23,113	310	1
Average capacity factor, excluding peakers	43.0%	46.4%	(3.4)	(7)
Steam Adjusted Heat Rate	7,271	7,268	(3)	—

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\# Variance of 100% or greater

(1) Amount represents the unrealized portion of our mark-to-market activity as well as a non-cash gain from amortization of prepaid power sales agreements.

(2) Includes $2 million and nil of REC expense for the three months ended June 30, 2009 and 2008, respectively, which is a component of Commodity Margin.

(3) Represents generation from power plants that we both consolidate and operate.

Commodity revenue, net of commodity expense, decreased $23 million for the three months ended June 30, 2009, compared to the same period in 2008 primarily due to decreases in Commodity Margin in the West and Texas of $11 million and $19 million, respectively, resulting from lower market spark spreads given lower power demand and lower gas prices partially offset by higher hedge levels and hedge prices. Commodity Margin in the Southeast and North increased $2 million and $3 million, respectively.

Net unrealized mark-to-market activity primarily resulting from our portfolio hedging activities that do not qualify for hedge accounting decreased $241 million for the three months ended June 30, 2009, compared to the same period in 2008 primarily driven by the large mark-to-market gain in the second quarter of 2008 caused by the impact of rising natural gas prices on fuel purchases. In addition, the mark-to-market loss for the three months ended June 30, 2009, resulted from the impact of rising natural gas prices in the second quarter of 2009 on our gas sales used to economically hedge a portion of our spark spread for 2010 and 2011.

Other revenue decreased $7 million primarily related to a $3 million decrease in revenue from construction management projects completed in 2008 and a $3 million decrease in revenue from an operation and maintenance contract.

Normal, recurring costs in plant operating expense decreased in the three months ended June 30, 2009, compared to the same period in 2008 after accounting for $7 million in reimbursements for insurance claims from prior periods that reduced expenses in the second quarter of 2008.

Other cost of revenue decreased for the three months ended June 30, 2009, compared to the three months ended June 30, 2008, as a result of a decrease of $7 million related to the discontinuation of the amortization of other assets associated with the sale of Auburndale in 2008 as well as a $4 million decrease in royalty expense due to lower revenues from our Geysers Assets resulting from lower spot market power prices in the second quarter of 2009 compared to 2008.

Our income from unconsolidated investments in power plants increased for the three months ended June 30, 2009, compared to the three months ended June 30, 2008, primarily resulting from income from our investment in Greenfield LP of $5 million for the three months ended June 30, 2009, compared to a loss of $2 million for the three months ended June 30, 2008, which is due to Greenfield LP achieving commercial operations in October 2008.

Other operating expense decreased for the three months ended June 30, 2009, compared to the three months ended June 30, 2008, primarily due to a $6 million impairment related to the discontinuation of the development of a power project recorded during the second quarter of 2008.

Interest income decreased for the three months ended June 30, 2009, compared to the same period in 2008 due to lower average interest rates.

Debt extinguishment costs increased for the three months ended June 30, 2009, compared to the same period in 2008 primarily due to $33 million in debt extinguishment costs associated with the refinancing of our CCFC Old Notes and CCFC Term Loans in May and June 2009 and the CCFCP Preferred Shares that were redeemed on or before June 30, 2009. This was compared to a $6 million loss for the write-off of unamortized deferred financing costs and other costs associated with the refinancing of our Metcalf term loan facility and preferred interests in June 2008.

Other (income) expense, net changed unfavorably for the three months ended June 30, 2009, compared to the same period in 2008 due primarily to a $7 million unfavorable change in foreign exchange losses.

Reorganization items decreased for the three months ended June 30, 2009, compared to June 30, 2008, due to higher professional and trustee fees incurred in the second quarter of 2008 related to our Chapter 11 and CCAA cases.

For the three months ended June 30, 2009, we recorded income tax expense of $15 million compared to $25 million for the three months ended June 30, 2008. See Note 1 of the Notes to Consolidated Condensed Financial Statements for further information.

Results of Operations for the Six Months Ended June 30, 2009 and 2008

Below are the results of operations for the six months ended June 30, 2009, as compared to the same period in 2008 (in millions, except for percentages and operating performance metrics). We have modified our presentation of commodity revenue and commodity expense to include cash settlements from our marketing, hedging and optimization activities that were previously included in mark-to-market activity. Our 2008 commodity revenue and expense information has been reclassified to conform to the current period presentation. In the "$ Change" and ''% Change" columns below, increases in revenue/income or decreases in expense (favorable variances) are shown without brackets while decreases in revenue/income or increases in expense (unfavorable variances) are shown with brackets.

	2009	2008	$ Change	% Change
Operating revenues:				
Commodity revenue	$ 3,053	$ 4,960	$ (1,907)	(38) %
Mark-to-market activity(1)	84	(204)	288	#
Other revenue	11	23	(12)	(52)
Operating revenues	3,148	4,779	(1,631)	(34)
Cost of revenue:				
Fuel and purchased energy expense:				
Commodity expense	1,870	3,772	1,902	50
Mark-to-market activity(1)	67	(159)	(226)	#
Fuel and purchased energy expense	1,937	3,613	1,676	46
Plant operating expense	458	438	(20)	(5)
Depreciation and amortization expense	222	219	(3)	(1)
Other cost of revenue(2)	43	62	19	31
Total cost of revenue	2,660	4,332	1,672	39
Gross profit	488	447	41	9
Sales, general and other administrative expense	93	96	3	3
Income from unconsolidated investments in power plants	(40)	(13)	27	#
Other operating expense	9	13	4	31
Income from operations	426	351	75	21
Interest expense	417	625	208	33
Interest (income)	(10)	(27)	(17)	(63)
Debt extinguishment costs	33	13	(20)	#
Other (income) expense, net	4	(2)	(6)	#
Loss before reorganization items and income taxes	(18)	(258)	240	93
Reorganization items	6	(261)	(267)	#
Income (loss) before income taxes	(24)	3	(27)	#
Income tax expense	24	20	(4)	(20)
Net loss	(48)	(17)	(31)	#
Add: Net loss attributable to the noncontrolling interest	2	—	2	—
Net loss attributable to Calpine	$ (46)	$ (17)	$ (29)	#

Operating Performance Metrics:	2009	2008	Change	% Change
MWh generated (in thousands)(3)	38,666	42,117	(3,451)	(8) %
Average availability	90.8%	87.9%	2.9	3
Average total MW in operation	23,423	23,113	310	1
Average capacity factor, excluding peakers	43.1%	46.3%	(3.2)	(7)
Steam Adjusted Heat Rate	7,230	7,215	(15)	—

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\# Variance of 100% or greater

(1) Amount represents the unrealized portion of our mark-to-market activity as well as a non-cash gain from amortization of prepaid power sales agreements.

(2) Includes $4 million and nil of REC expense for the six months ended June 30, 2009 and 2008, respectively, which is a component of Commodity Margin.

(3) Represents generation from power plants that we both consolidate and operate.

Commodity revenue, net of commodity expense, decreased $5 million for the six months ended June 30, 2009, compared to the same period in 2008 primarily due to the following regional factors:

- *West* — Commodity Margin increased 1% as a result of higher hedge levels, higher average hedge prices and sales of surplus emission allowances in the first quarter of 2009.
- *Texas* — Commodity Margin decreased 10% due to weaker natural gas prices and Market Heat Rates as well as the comparative impact of congestion-driven pricing observed in the second quarter of 2008 that was much greater than the second quarter of 2009.
- *Southeast* — Commodity Margin increased 25% due to higher average hedge prices and higher Market Heat Rates. These factors were partially offset by the negative impact from an unfavorable arbitration ruling on a steam contract during the second quarter of 2009 and a gain of $21 million related to the temporary assignment of a transmission capacity contract in the second quarter of 2008.
- *North* — Commodity Margin decreased 7% due to lower average hedge prices which was partially offset by the impact of rate increases for the power sales agreements associated with our New York generation assets and lower fuel expenses.

Net unrealized mark-to-market activity primarily resulting from our portfolio hedging activities that do not qualify for hedge accounting increased $62 million for the six months ended June 30, 2009, compared to the same period in 2008 primarily driven by the positive impact of the difference in the large mark-to-market loss in the first half of 2008 related to power derivative contracts caused by the impact of rising power prices and mark-to-market gains in the first half of 2009 related to Heat Rate swaps and options and fixed price power contracts primarily in the West. This variance was partially offset by the negative impact of the difference in the large mark-to-market gain related to natural gas derivative contracts in the first half of 2008 caused by the impact of rising natural gas prices on fuel purchases and the mark-to-market loss related to natural gas derivative contracts in the first half of 2009 resulting from the impact of rising natural gas prices, primarily during the second quarter of 2009, on our gas sales used to economically hedge a portion of our spark spread for 2010 and 2011.

Other revenue decreased $12 million primarily related to a $6 million decrease in revenue from construction management projects completed in 2008 and a $5 million decrease in revenue from an operation and maintenance contract.

Normal, recurring costs in plant operating expense decreased for the six months ended June 30, 2009, compared to the same period in 2008 after accounting for $15 million in reimbursements for insurance claims from prior periods that reduced expenses in the first half of 2008 as well as a $6 million increase in major maintenance costs resulting from our outage schedule.

Other cost of revenue decreased for the six months ended June 30, 2009, compared to the six months ended June 30, 2008, as a result of a decrease of $14 million related to the discontinuation of the amortization of other assets associated with the deconsolidation and subsequent sale of Auburndale in 2008 as well as a $7 million decrease in royalty expense due to lower revenues from our Geysers Assets resulting from lower spot market power prices in the first half of 2009 compared to 2008.

Our income from unconsolidated investments in power plants increased for the six months ended June 30, 2009, compared to the six months ended June 30, 2008, primarily resulting from income from our investment in Greenfield LP of $10 million for the six months ended June 30, 2009, compared to a loss of $8 million for the six months ended June 30, 2008, which is due to Greenfield LP achieving commercial operations in October 2008 as well as an $11 million increase in income from our investment in OMEC compared to 2008 primarily resulting from unrealized mark-to-market gains from its interest rate swap contracts.

Other operating expense decreased for the six months ended June 30, 2009, compared to the six months ended June 30, 2008, primarily due to a $6 million impairment related to the discontinuation of the development of a power project recorded during the second quarter of 2008.

Due to the changes in our capital structure on the Effective Date, our interest expense for six months ended June 30, 2009 and 2008, is not comparable. Interest expense decreased primarily due to $135 million in post-petition interest related to pre-emergence debt recorded in the first quarter of 2008. In addition, interest expense decreased for the six months ended June 30, 2009, compared to the six months ended June 30, 2008, due to lower average debt balances and lower average interest rates. During the first quarter of 2008, we settled a portion of our debt through payment of cash and issuance of common stock pursuant to the Plan of Reorganization. Additionally, interest rates on our variable rate debt were lower for the six months ended June 30, 2009, compared to 2008, due to a decrease in LIBOR over the same periods. The annualized effective interest rates on our consolidated debt, excluding the impacts of items not directly attributed to the cost of the debt instruments, after amortization of deferred financing costs and debt discounts, were 8.0% and 9.0% for the six months ended June 30, 2009 and 2008, respectively. Also contributing to the overall decrease was $27 million for settlement obligations related to our Canadian Debtors and other foreign entities recorded prior to their reconsolidation in February 2008.

Interest income decreased for the six months ended June 30, 2009, compared to the same period in 2008 largely resulting from lower average interest rates.

Debt extinguishment costs increased for the six months ended June 30, 2009 compared to the same period in 2008 primarily due to $33 million in debt extinguishment costs associated with the refinancing of our CCFC Old Notes and CCFC Term Loans in May and June 2009 and the CCFCP Preferred Shares that were redeemed on or before June 30, 2009. This increase was partially offset by $7 million in refinancing costs related to the refinancing of all outstanding indebtedness under the existing Blue Spruce term loan facility in the first half of 2008 as well as $6 million for the write-off of unamortized deferred financing costs and other costs associated with the refinancing of our Metcalf term loan facility and preferred interests in June 2008.

Other (income) expense, net changed unfavorably for the six months ended June 30, 2009, compared to the same period in 2008 due primarily to a $7 million unfavorable change in foreign exchange losses.

During the six months ended June 30, 2008, reorganization items primarily consisted of $203 million in gains on asset sales, a $65 million gain on the reconsolidation of our Canadian Debtors, a $62 million credit related to the settlement of claims with the Canadian Debtors and $76 million in professional and trustee fees related to activity managed by our third party advisors for our Chapter 11 and CCAA cases.

For the six months ended June 30, 2009, we recorded income tax expense of $24 million compared to $20 million for the six months ended June 30, 2008. See Note 1 of the Notes to Consolidated Condensed Financial Statements for further information.

Commodity Margin and Adjusted EBITDA

Management's Discussion and Analysis of Financial Condition and Results of Operations includes financial information prepared in accordance with GAAP, as well as the non-GAAP financial measures, Commodity Margin and Adjusted EBITDA, discussed below, which we use as a measure of our performance. Generally, a non-GAAP financial measure is a numerical measure of financial performance, financial position or cash flows that excludes (or includes) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP.

Commodity Margin by Segment for the Three Months Ended June 30, 2009 and 2008

We use the non-GAAP financial measure "Commodity Margin" to assess our performance by our reportable segments. Commodity Margin includes our power and steam revenues, capacity revenue, REC revenue and expense, transmission revenue and expenses, fuel and purchased energy expense, and cash settlements from our marketing, hedging and optimization activities that are included in mark-to-market activity, but excludes the unrealized portion of our mark-to-market activity and other revenue. We believe that Commodity Margin is a useful tool for assessing the performance of our core operations and is a key operational measure reviewed by our chief operating decision maker. Commodity Margin is not a measure calculated in accordance with GAAP, and should be viewed as a supplement to and not a substitute for our results of operations presented in accordance with GAAP. Commodity Margin does not intend to represent gross profit (loss), the most comparable GAAP measure, as an indicator of operating performance and is not necessarily comparable to similarly-titled measures reported by other companies. See Note 13 of the Notes to Consolidated Condensed Financial Statements for a reconciliation of Commodity Margin to net income (loss) by segment.

The following tables show our Commodity Margin and related operating performance metrics by segment for the three months ended June 30, 2009 and 2008. During the first quarter of 2009, we began assessing the performance of our regional segments to include the allocation, based upon MWh, of revenues and expenses from our fuel management, TMG, certain non-region specific natural gas marketing and optimization and other corporate activities to our operating segments that were formerly non-allocated and previously reported as our "Other" segment. Additionally, we have modified our definition of Commodity Margin to include cash settlements from our marketing, hedging and optimization activities that were previously included in mark-to-market activity. Our 2008 Commodity Margin by segment information has been recast to conform to the current period presentation. In the "Change" and "% Change" columns below, favorable variances are shown without brackets while unfavorable variances are shown with brackets.

West:	**2009**	**2008**	**Change**	**% Change**
Commodity Margin (in millions)	$ 304	$ 315	$ (11)	(3)%
Commodity Margin per MWh generated	$ 45.21	$ 39.46	$ 5.75	15
MWh generated (in thousands)	6,724	7,982	(1,258)	(16)
Average availability	91.2%	89.6%	1.6	2
Average total MW in operation	7,246	7,246	—	—
Average capacity factor, excluding peakers	48.5%	57.3%	(8.8)	(15)
Steam Adjusted Heat Rate	7,414	7,319	(95)	(1)

West — Commodity Margin in our West segment decreased by $11 million, or 3%, for the three months ended June 30, 2009, compared to the three months ended June 30, 2008. During the second quarter of 2009, our West segment benefitted from higher hedge levels, higher average hedge prices and a 2% increase in our average availability as compared to the second quarter of 2008. Despite these positive factors, a weaker power market price environment driven by lower natural gas prices, lower industrial demand and milder weather led to a decrease in Commodity Margin for the three months ended June 30, 2009 compared to 2008. Consistent with the weaker price conditions, generation decreased 16% for the three months ended June 30, 2009, compared to the same period in 2008. Commodity Margin per MWh generated increased 15% due in part to the effect of our positive portfolio hedge value being allocated across a reduced number of generated MWh in the second quarter of 2009 as compared to 2008.

Texas:	**2009**	**2008**	**Change**	**% Change**
Commodity Margin (in millions)	$ 196	$ 215	$ (19)	(9)%
Commodity Margin per MWh generated	$ 25.77	$ 22.69	$ 3.08	14
MWh generated (in thousands)	7,605	9,477	(1,872)	(20)
Average availability	90.7%	91.8%	(1.1)	(1)
Average total MW in operation	7,251	7,251	—	—
Average capacity factor, excluding peakers	48.0%	59.8%	(11.8)	(20)
Steam Adjusted Heat Rate	7,132	7,144	12	—

Texas — Commodity Margin in our Texas segment decreased by $19 million, or 9%, for the three months ended June 30, 2009, compared to the same period in 2008 largely resulting from weaker natural gas prices and Market Heat Rates that decreased 68% and 23%, respectively. Although April and May 2009 Market Heat Rates were weak as a result of weak industrial demand and mild weather, Market Heat Rates were robust during June 2009 as a result of much warmer than normal temperatures. Despite the strength seen in June 2009, the overall pricing for the second quarter of 2009 fell well short of the same period in 2008 primarily due to the congestion-driven pricing in the second quarter of 2008. Generation decreased 20% resulting primarily from the weak April and May 2009 pricing compared to the same periods in 2008, as well as, to a lesser extent, unscheduled outages at our Pasadena and Magic Valley power plants in the second quarter of 2009. Commodity Margin per MWh generated increased 14% due in part to the effect of our positive portfolio hedge value being allocated across a reduced number of generated MWh in the second quarter of 2009 as compared to 2008.

Southeast:	**2009**	**2008**	**Change**	**% Change**
Commodity Margin (in millions)	$ 80	$ 78	$ 2	3%
Commodity Margin per MWh generated	$ 20.22	$ 29.60	$ (9.38)	(32)
MWh generated (in thousands)	3,957	2,635	1,322	50
Average availability	87.7%	89.3%	(1.6)	(2)
Average total MW in operation	6,104	6,254	(150)	(2)
Average capacity factor, excluding peakers	34.6%	21.2%	13.4	63
Steam Adjusted Heat Rate	7,241	7,459	218	3

Southeast — Commodity Margin in our Southeast segment increased by $2 million, or 3%, driven by both higher average hedge prices and higher Market Heat Rates in the second quarter of 2009 compared to 2008. The increase in Market Heat Rates and the associated 50% increase in generation for the three months ended June 30, 2009, compared to 2008 were attributable in part to warmer weather in particular market areas and natural gas generation displacement of coal generation in certain sub-markets in our Southeast segment. Additionally, some of our plants benefited from the impact of advantageous transmission, off-take and transportation agreements in the second quarter of 2009. These positive performance factors were largely offset by the negative impact from an unfavorable arbitration ruling on a steam contract, which impacted our operating revenues during the second quarter of 2009 and a gain of $21 million related to the temporary assignment of a transmission capacity contract in the three months ended June 30, 2008.

North:	**2009**	**2008**	**Change**	**% Change**
Commodity Margin (in millions)	$ 70	$ 67	$ 3	4%
Commodity Margin per MWh generated	$ 62.89	$ 59.98	$ 2.91	5
MWh generated (in thousands)	1,113	1,117	(4)	—
Average availability	96.0%	87.4%	8.6	10
Average total MW in operation	2,822	2,362	460	19
Average capacity factor, excluding peakers	27.1%	28.0%	(0.9)	(3)
Steam Adjusted Heat Rate	7,687	7,635	(52)	(1)

North — Commodity Margin in our North segment increased by $3 million, or 4%, due to rate increases for the power sales agreements associated with our New York generation assets, lower fuel expenses and the reconsolidation of RockGen in December 2008. As a result of this reconsolidation, our average total MW in operation increased 19% for the three months ended June 30, 2009, compared to 2008. Partially offsetting these positive factors was a reclassification of transmission expense to Commodity Margin that had previously been recognized in plant operating expense as well as lower realized spark spreads for the three months ended June 30, 2009, compared to 2008.

Commodity Margin by Segment for the Six Months Ended June 30, 2009 and 2008

The following tables show our Commodity Margin and related operating performance metrics by segment for the six months ended June 30, 2009 and 2008. Our 2008 Commodity Margin by segment information has been recast to conform to the current period presentation. In the "Change" and "% Change" columns below, favorable variances are shown without brackets while unfavorable variances are shown with brackets.

West:	**2009**	**2008**	**Change**	**% Change**
Commodity Margin (in millions)	$ 601	$ 593	$ 8	1%
Commodity Margin per MWh generated	$ 38.38	$ 34.60	$ 3.78	11
MWh generated (in thousands)	15,661	17,139	(1,478)	(9)
Average availability	90.8%	86.5%	4.3	5
Average total MW in operation	7,246	7,246	—	—
Average capacity factor, excluding peakers	56.8%	61.9%	(5.1)	(8)
Steam Adjusted Heat Rate	7,296	7,269	(27)	—

West — Commodity Margin in our West segment increased by $8 million, or 1%, for the six months ended June 30, 2009, compared to the six months ended June 30, 2008. Although market spark spreads for the six months ended June 30, 2009 settled substantially lower than the same period in 2008, Commodity Margin in the West improved primarily as a result of higher hedge levels, higher average hedge prices and sales of surplus emission allowances in the first quarter of 2009. Consistent with the weaker price conditions, generation decreased 9% for the three months ended June 30, 2009, compared to the same period in 2008 despite a 5% increase in our average availability. Commodity Margin per MWh generated increased 11% due in part to the effect of our positive portfolio hedge value being allocated across a reduced number of generated MWh in the first half of 2009 as compared to 2008.

Texas:	**2009**	**2008**	**Change**	**% Change**
Commodity Margin (in millions)	$ 318	$ 354	$ (36)	(10)%
Commodity Margin per MWh generated	$ 24.82	$ 20.56	$ 4.26	21
MWh generated (in thousands)	12,812	17,218	(4,406)	(26)
Average availability	89.5%	86.9%	2.6	3
Average total MW in operation	7,251	7,251	—	—
Average capacity factor, excluding peakers	40.7%	54.4%	(13.7)	(25)
Steam Adjusted Heat Rate	7,086	7,057	(29)	—

Texas — Commodity Margin in our Texas segment decreased by $36 million, or 10%, for the six months ended June 30, 2009, compared to the same period in 2008 largely resulting from weaker natural gas prices which decreased 61% and weaker Market Heat Rates in the second quarter of 2009 compared to 2008 that decreased 23%. Overall pricing for the first half of 2009 fell well short of the same period in 2008 primarily due to the congestion-driven pricing in the second quarter of 2008. Despite a 3% increase in our average availability, generation decreased 26% resulting primarily from weaker Market Heat Rates in the second quarter of 2009. Commodity Margin per MWh generated increased 21% due in part to the effect of our positive portfolio hedge value being allocated across a reduced number of generated MWh in the first half of 2009 as compared to 2008.

Southeast:	**2009**	**2008**	**Change**	**% Change**
Commodity Margin (in millions)	$ 141	$ 113	$ 28	25%
Commodity Margin per MWh generated	$ 17.99	$ 21.30	$ (3.31)	(16)
MWh generated (in thousands)	7,836	5,305	2,531	48
Average availability	90.9%	90.2%	0.7	1
Average total MW in operation	6,104	6,254	(150)	(2)
Average capacity factor, excluding peakers	34.5%	21.9%	12.6	58
Steam Adjusted Heat Rate	7,235	7,460	225	3

Southeast — Commodity Margin in our Southeast segment increased by $28 million, or 25%, driven primarily by both higher average hedge prices and higher Market Heat Rates in the first half of 2009 compared to 2008. The increase in Market Heat Rates and the resulting 48% increase in generation for the first half of 2009 compared to 2008 was attributable in part to warmer weather in particular market areas and gas generation displacement of coal generation in certain sub-markets. Additionally, some of our plants benefited from the impact of advantageous transmission, off-take and transportation agreements in the first half of 2009. These positive performance factors were partially offset by the negative impact from an unfavorable arbitration ruling on a steam contract, which impacted our operating revenues during the second quarter of 2009 and a gain of $21 million related to the temporary assignment of a transmission capacity contract in the second quarter of 2008.

North:	**2009**	**2008**	**Change**	**% Change**
Commodity Margin (in millions)	$ 119	$ 128	$ (9)	(7)%
Commodity Margin per MWh generated	$ 50.49	$ 52.14	$ (1.65)	(3)
MWh generated (in thousands)	2,357	2,455	(98)	(4)
Average availability	94.0%	89.7%	4.3	5
Average total MW in operation	2,822	2,362	460	19
Average capacity factor, excluding peakers	29.5%	31.1%	(1.6)	(5)
Steam Adjusted Heat Rate	7,658	7,516	(142)	(2)

North — Commodity Margin in our North segment decreased by $9 million, or 7%, primarily due to lower average hedge prices during the six months ended June 30, 2009, compared to 2008. Despite a 5% increase in our average availability and an increase of 460 MW in operation, generation declined by 4% in the first half of 2009 compared to the same period in 2008. The decrease in Commodity Margin in the first half of 2009 compared to 2008 was partially offset by rate increases for the power sales agreements associated with our New York generation assets and lower fuel expenses. The 460 MW or 19% increase in our average total MW in operation for the six months ended June 30, 2009, compared to 2008 was due to the reconsolidation of RockGen in December 2008.

Adjusted EBITDA

We define Adjusted EBITDA as EBITDA adjusted for certain items described below and presented in the accompanying reconciliation. Adjusted EBITDA is not a measure calculated in accordance with GAAP, and should be viewed as a supplement to and not a substitute for our results of operations presented in accordance with GAAP. Our Exit Credit Facility and certain of our other debt instruments, including the Commodity Collateral Revolver, include a similar measure as a basis for our material covenants under those debt agreements that excludes our net interest in our unconsolidated subsidiaries and non-cash loss on dispositions of assets. However, we believe that inclusion of our share of the Adjusted EBITDA of our unconsolidated subsidiaries and exclusion of non-cash loss on dispositions of assets are useful in evaluating our overall performance and therefore include these items in our definition of Adjusted EBITDA. Adjusted EBITDA is not intended to represent cash flows from operations or net income (loss) as defined by GAAP as an indicator of operating performance. Furthermore, Adjusted EBITDA is not necessarily comparable to similarly-titled measures reported by other companies.

We believe Adjusted EBITDA is also used by and is useful to investors and other users of our financial statements in evaluating our operating performance because it provides them with an additional tool to compare business performance across companies and across periods. We believe that EBITDA is widely used by investors to measure a company's operating performance without regard to items such as interest expense, taxes, depreciation and amortization, which can vary substantially from company to company depending upon accounting methods and book value of assets, capital structure and the method by which assets were acquired.

Additionally, we believe that investors commonly adjust EBITDA information to eliminate the effect of restructuring and other expenses, which vary widely from company to company and impair comparability. As we define it, Adjusted EBITDA represents EBITDA (Earnings Before Interest, Taxes, Depreciation and Amortization) adjusted to remove the income effects of non-cash losses on sales, dispositions or impairments of assets, any unrealized gains or losses and any non-cash realized gains or losses from accounting for derivatives, non-cash stock compensation expense, operating lease expense, non-cash gains and losses from intercompany foreign currency translations, reorganization items, major maintenance expense, gains or losses on the repurchase or extinguishment of debt and any other extraordinary, unusual or non-recurring income plus our net interest in the Adjusted EBITDA of our unconsolidated investments. We exclude these items from Adjusted EBITDA as our management believes that these items would distort their ability to efficiently view and assess our core operating trends.

In summary, our management uses Adjusted EBITDA as a measure of operating performance to assist in comparing performance from period to period on a consistent basis and to readily view operating trends, as a measure for planning and forecasting overall expectations and for evaluating actual results against such expectations, and in communications with our Board of Directors, shareholders, creditors, analysts and investors concerning our financial performance.

The table below provides a reconciliation of Adjusted EBITDA by operating segment to our income from operations for the three and six months ended June 30, 2009 and 2008 (in millions). No items listed below income (loss) from operations as reported on our Consolidated Condensed Statements of Operations are included in the table as they are excluded from Adjusted EBITDA.

	Three Months Ended June 30, 2009					
	West	Texas	Southeast	North	Consolidation and Elimination	Total
Income (loss) from operations	$ 195	$ (48)	$ (6)	$ 39	$ (5)	$ 175
Add:						
Adjustments to reconcile income (loss) from operations to Adjusted EBITDA:						
Depreciation and amortization expense, excluding deferred financing costs(1)	52	32	18	15	(1)	116
Major maintenance expense	24	2	12	2	—	40
Operating lease expense	4	—	—	7	—	11
Unrealized (gains) losses on commodity derivative mark-to-market activity	(50)	144	26	(12)	—	108
Adjustments to reflect Adjusted EBITDA from unconsolidated investments(3)(4)	(16)	—	—	1	—	(15)
Stock-based compensation expense	3	4	1	1	—	9
Non-cash loss on dispositions of assets	1	5	2	1	—	9
Other	1	—	2	1	—	4
Adjusted EBITDA	$ 214	$ 139	$ 55	$ 55	$ (6)	$ 457

	Three Months Ended June 30, 2008(5)					
	West	Texas	Southeast	North	Consolidation and Elimination	Total
Income from operations	$ 206	$ 153	$ 37	$ 40	$ (3)	$ 433
Add:						
Adjustments to reconcile income from operations to Adjusted EBITDA:						
Depreciation and amortization expense, excluding deferred financing costs(1)	45	34	27	13	(1)	118
Impairment charges	6	—	—	—	—	6
Major maintenance expense	23	9	11	(1)	—	42
Operating lease expense	5	—	—	6	—	11
Non-cash gains on derivatives(2)	—	(11)	—	—	—	(11)
Unrealized gains on commodity derivative mark-to-market activity	(52)	(34)	(15)	(21)	—	(122)
Adjustments to reflect Adjusted EBITDA from unconsolidated investments(3)(4)	(15)	—	—	3	—	(12)
Stock-based compensation expense	5	5	2	1	—	13
Non-cash loss on dispositions of assets	1	1	—	1	(1)	2
Other	—	1	—	(2)	—	(1)
Adjusted EBITDA	$ 224	$ 158	$ 62	$ 40	$ (5)	$ 479

	Six Months Ended June 30, 2009					
	West	Texas	Southeast	North	Consolidation and Elimination	Total
Income from operations	$ 312	$ 37	$ 28	$ 51	$ (2)	$ 426
Add:						
Adjustments to reconcile income from operations to Adjusted EBITDA:						
Depreciation and amortization expense, excluding deferred financing costs(1)	102	63	36	31	(3)	229
Major maintenance expense	58	29	16	(1)	—	102
Operating lease expense	10	—	—	13	—	23
Unrealized (gains) losses on commodity derivative mark-to-market activity	(61)	60	(2)	(14)	—	(17)
Adjustments to reflect Adjusted EBITDA from unconsolidated investments(3)(4)	(26)	—	—	9	—	(17)
Stock-based compensation expense	10	7	3	2	—	22
Non-cash loss on dispositions of assets	6	7	2	2	—	17
Other	2	—	—	1	—	3
Adjusted EBITDA	$ 413	$ 203	$ 83	$ 94	$ (5)	$ 788

	Six Months Ended June 30, 2008(5)					
	West	Texas	Southeast	North	Consolidation and Elimination	Total
Income (loss) from operations	$ 232	$ 49	$ (6)	$ 75	$ 1	$ 351
Add:						
Adjustments to reconcile income (loss) from operations to Adjusted EBITDA:						
Depreciation and amortization expense, excluding deferred financing costs(1)	97	66	54	25	(2)	240
Impairment charges	6	—	—	—	—	6
Major maintenance expense	45	32	13	6	—	96
Operating lease expense	11	—	—	12	—	23
Non-cash gains on derivatives(2)	—	(20)	—	—	—	(20)
Unrealized (gains) losses on commodity derivative mark-to-market activity	6	102	—	(43)	—	65
Adjustments to reflect Adjusted EBITDA from unconsolidated investments(3)(4)	(15)	—	—	10	—	(5)
Stock-based compensation expense	9	6	3	1	—	19
Non-cash loss on dispositions of assets	7	1	1	—	(1)	8
Other	(6)	5	—	(2)	—	(3)
Adjusted EBITDA	$ 392	$ 241	$ 65	$ 84	$ (2)	$ 780

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(1) Depreciation and amortization expense in the income (loss) from operations calculation on our Consolidated Condensed Statements of Operations excludes amortization of other assets and amounts classified as sales, general and other administrative expenses.

(2) Includes realized non-cash gains on derivatives that do not qualify for hedge accounting.

(3) Included in our Consolidated Condensed Statements of Operations in income from unconsolidated investments in power plants.

(4) Adjustments to reflect Adjusted EBITDA from unconsolidated investments include $(20) million and $(14) million in unrealized losses on mark-to-market activity for the three months ended June 30, 2009 and 2008, respectively, and $(28) million and $(8) million for the six months ended June 30, 2009 and 2008, respectively.

(5) Adjusted EBITDA for the three and six months ended June 30, 2008, has been recast to conform to our current period definition.

Risk Management and Commodity Accounting

We actively seek to manage the commodity risks of our portfolio, utilizing multiple strategies of buying and selling power or natural gas to manage our spark spread, or selling Heat Rate transactions.

We utilize derivatives, which are defined to include physical commodity contracts and financial commodity instruments such as swaps and options and NYMEX contracts to manage commodity price risk and to maximize the risk-adjusted returns from our power and natural gas assets. We conduct these hedging and optimization activities within a structured risk management framework based on controls, policies and procedures. We monitor these activities through active and ongoing management and oversight, defined roles and responsibilities, and daily risk measurement and reporting. Additionally, we seek to manage the associated risks through diversification, by controlling position sizes, by using portfolio position limits, and by entering into offsetting positions that lock in a margin.

Along with our portfolio of hedging transactions, we enter into power and natural gas positions that often act as hedges to our asset portfolio, but do not qualify as hedges under hedge accounting criteria guidelines, such as commodity options transactions and instruments that settle on power price to natural gas price relationships (Heat Rate swaps and options). While our selling and purchasing of power and natural gas is mostly physical in nature, we also engage in marketing, hedging and optimization activities, particularly in natural gas, that are financial in nature. While we enter into these transactions primarily to provide us with improved price and price volatility transparency as well as greater market access, which benefits our hedging activities, we also are susceptible to commodity price movements (both profits and losses) in connection with these transactions. These positions are included in and subject to our consolidated risk management portfolio position limits and controls structure. Changes in fair value of commodity positions that do not qualify for either hedge accounting or the normal purchase normal sale exemption are recognized currently in earnings in mark-to-market activity within operating revenues in the case of power transactions, and within fuel and purchased energy expense, in the case of natural gas transactions. Our future hedged status, and marketing and optimization activities are subject to change as determined by our commercial operations group, Chief Risk Officer, Risk Management Committee of senior management and Board of Directors.

We have economically hedged a substantial portion of our generation and natural gas portfolio mostly through power and natural gas forward physical and financial transactions for the remainder of 2009. By entering into these transactions, we are able to economically hedge a portion of our spark spread at pre-determined generation and price levels. We utilize a combination of PPAs and other hedging instruments to manage our variability in future cash flows. As of June 30, 2009, the maximum length of our PPAs extend until 24 years into the future and the maximum length of time over which we were hedging using commodity and interest rate derivative instruments was 4 and 17 years, respectively. Assuming constant June 30, 2009, power and natural gas prices and interest rates, we estimate that pre-tax, net gains of $161 million would be reclassified from AOCI into earnings during the next 12 months as the hedged transactions settle; however, the actual amounts that will be reclassified will vary based on changes in natural gas and power prices as well as interest rates. Therefore, we are unable to predict what the actual reclassification from AOCI to earnings (positive or negative) will be for the next 12 months.

Derivatives — We enter into a variety of derivative instruments such as exchange traded and OTC power and natural gas forwards, options and interest rate swaps. Derivative contracts are measured at their fair value and recorded as either assets or liabilities unless they qualify for and we elect the normal purchase or normal sale exemption. All changes in the fair value of contracts accounted for as derivatives are recognized currently in earnings (as a component of our operating revenues, fuel and purchased energy expense, or interest expense) unless specific hedge criteria are met. The hedge criteria requires us to formally document, designate and assess the effectiveness of transactions that receive hedge accounting. The actual amounts that will ultimately be settled will likely vary based on changes in natural gas prices and power prices as well as changes in interest rates. Such variances could be material.

The primary factors affecting our market risk and the fair value of our derivatives at any point in time are the volume of open derivative positions (MMBtu and MWh), changing commodity market prices, principally for power and natural gas, liquidity risk, counterparty credit risk and changes in interest rates. Because prices for power 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. Significant volatility in both natural gas and power prices as well as increased hedging and optimization activities have had a significant impact on the presentation of our derivative assets and liabilities. Our derivative assets and liabilities have decreased to $3.7 billion and $(3.7) billion at June 30, 2009, compared to $4.1 billion and $(4.5) billion at December 31, 2008, respectively. As of June 30, 2009, the fair value of our level 3 derivative assets and liabilities represent only a small portion of our total assets and liabilities (less than 1%). There is a substantial amount of volatility inherent in accounting for the fair value of these derivatives, and our results during the three and six months ended June 30, 2009, have reflected this as discussed below.

The change in fair value of our outstanding commodity and interest rate derivative instruments from January 1, 2009, through June 30, 2009, is summarized in the table below (in millions):

	Interest Rate Swaps	Commodity Instruments	Total
Fair value of contracts outstanding at January 1, 2009	$ (452)	$ 12	$ (440)
Losses recognized or otherwise settled during the period	91(1)	141(2)	232
Fair value attributable to new contracts	(1)	25	24
Changes in fair value attributable to price movements	46	224	270
Change in fair value attributable to nonperformance risk	(47)	(1)	(48)
Fair value of contracts outstanding at June 30, 2009(3)	$ (363)	$ 401	$ 38

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(1) Interest rate settlements consist of recognized losses from interest rate cash flow hedges of $(82) million and recognized losses from undesignated interest rate swaps of $(9) million (represents a portion of interest expense as reported on our Consolidated Condensed Statements of Operations).

(2) Settlement of commodity contracts not designated as hedging instruments of $(103) million (represents a portion of operating revenues and fuel and purchased energy expense as reported on our Consolidated Condensed Statements of Operations) and $(38) million related to recognition of gains from cash flow hedges, previously reflected in OCI, offset by other changes in derivative assets and liabilities not reflected in OCI or net income (loss).

(3) Net commodity and interest rate derivative assets and liabilities reported in Notes 7 and 8 of the Notes to Consolidated Condensed Financial Statements.

The change since the last balance sheet date in the total value of the derivatives (both assets and liabilities) is reflected either in cash for option premiums paid or collected, in OCI, net of tax for cash flow hedges, or on our Consolidated Condensed Statements of Operations as a component (gain or loss) in current earnings.

The components of our total mark-to-market gain (loss) for our commodity instruments and interest rate swaps for the three and six months ended June 30, 2009 and 2008, are outlined below (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2009	2008	2009	2008
Realized gain (loss)(1)	$ 37	$ (104)	$ (25)	$ (68)
Unrealized gain (loss)	(103)	140	23	(63)
Total mark-to-market gain (loss)	$ (66)	$ 36	$ (2)	$ (131)

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(1) Balance includes a non-cash gain from amortization of prepaid power sales agreements of approximately $11 million and $20 million for the three and six months ended June 30, 2008, respectively.

Our change in AOCI from an accumulated loss of $(158) million at December 31, 2008, to an accumulated loss of $(5) million at June 30, 2009, was primarily driven by the effect of a decrease in power and natural gas prices, reclassification adjustment for cash flow hedges realized in net income, a decrease in interest rates and the effect of income taxes.

Commodity Price Risk — Commodity price risks result from exposure to changes in spot prices, forward prices, price volatilities and correlations between the price of power, steam and natural gas. We manage the commodity price risk and the variability in future cash flows from forecasted sales of power and purchases of natural gas of our entire portfolio of generating assets and contractual positions by entering into various derivative or non-derivative instruments.

The fair value of outstanding derivative commodity instruments at June 30, 2009, based on price source and the period during which the instruments will mature, are summarized in the table below (in millions):

Fair Value Source	2009	2010-2011	2012-2013	After 2013	Total
Prices actively quoted	$ 308	$ 462	$ (7)	$ —	$ 763
Prices provided by other external sources	51	(432)	18	—	(363)
Prices based on models and other valuation methods	—	—	—	1	1
Total fair value	$ 359	$ 30	$ 11	$ 1	$ 401

We measure the commodity price risks in our portfolio on a daily basis using a VAR model to estimate the maximum potential one-day risk of loss resulting from market movements in comparison to internally established thresholds. Our VAR is calculated for our entire portfolio which is comprised of commodity derivatives, power plants, PPAs, and other physical and financial transactions. The portfolio VAR calculation incorporates positions for the remaining portion of the current calendar year plus the following two calendar years. We measure VAR using a variance/covariance approach based on a confidence level of 95%, a one-day holding period, and actual observed historical correlation. While we believe that our VAR assumptions and approximations are reasonable, different assumptions and/or approximations could produce materially different estimates.

The table below presents the high, low and average of our daily VAR for the three and six months ended June 30, 2009 and 2008, as well as our VAR at June 30, 2009 and 2008 (in millions):

	2009	2008
Three months ended June 30:		
High	$ 55	$ 70
Low	$ 46	$ 47
Average	$ 50	$ 56
Six months ended June 30:		
High	$ 59	$ 70
Low	$ 46	$ 39
Average	$ 51	$ 50
As of June 30	$ 48	$ 66

Liquidity Risk — Liquidity risk arises from the general funding requirements needed to manage our activities and assets and liabilities. Increasing natural gas prices or Market Heat Rates can cause increased collateral requirements. Our liquidity management framework is intended to maximize liquidity access and minimize funding costs during times of rising prices. See further discussion regarding our uses of collateral as they relate to our commodity procurement and risk management activities in Note 8 of the Notes to Consolidated Condensed Financial Statements.

We have also borrowed $725 million under our Exit Credit Facility, as discussed in "— Liquidity and Capital Resources" above to, in part, mitigate our liquidity risk.

Credit Risk — Credit risk relates to the risk of loss resulting from non-performance or non-payment by our counterparties related to their contractual obligations with us. Risks surrounding counterparty performance and credit could ultimately impact the amount and timing of expected cash flows. We also have credit risk if counterparties are unable to provide collateral or post margin. We monitor and manage our credit risk through credit policies that include:

- Credit approvals;
- Routine monitoring of counterparties' credit limits and their overall credit ratings;
- Limiting our marketing, hedging and optimization activities with high risk counterparties;
- Margin, collateral, or prepayment arrangements; and
- Payment netting agreements, or master netting agreements that allow for the netting of positive and negative exposures of various contracts associated with a single counterparty.

We believe that our credit policies adequately monitor and diversify our credit risk. We currently have no individual significant concentrations of credit risk to a single counterparty; however, a series of defaults or events of nonperformance by several of our individual counterparties could impact our liquidity and future results of operations. We monitor and manage our total comprehensive credit risk associated with all of our contracts and PPAs irrespective of whether they are accounted for as a normal purchase or normal sale or whether they are marked-to-market and included in our derivative assets and liabilities on our Consolidated Condensed Balance Sheets. Our counterparty credit quality associated with the net fair value of outstanding derivative commodity instruments is included in our derivative assets and liabilities at June 30, 2009, and the period during which the instruments will mature are summarized in the table below (in millions):

Credit Quality (Based on Standard & Poor's Ratings as of June 30, 2009)	2009	2010-2011	2012-2013	After 2013	Total
Investment grade	$ 362	$ 29	$ 13	$ —	$ 404
Non-investment grade	(4)	—	—	—	(4)
No external ratings	1	1	(2)	1	1
Total fair value	$ 359	$ 30	$ 11	$ 1	$ 401

Interest Rate Risk — We are exposed to interest rate risk related to our variable rate debt. Interest rate risk represents the potential loss in earnings arising from adverse changes in market interest rates. Our variable rate financings are indexed to base rates, generally LIBOR. Significant LIBOR increases could have an adverse impact on our future interest expense.

Our fixed-rate debt instruments do not expose us to the risk of loss in earnings due to changes in market interest rates. In general, such a change in fair value would impact earnings and cash flows only if we were to reacquire all or a portion of the fixed rate debt in the open market prior to their maturity.

Currently, we use interest rate swaps to adjust the mix between fixed and floating rate debt as a hedge of our interest rate risk. We do not use interest rate derivative instruments for trading purposes. In order to manage our risk to significant increases in LIBOR, we have effectively hedged $7.1 billion of our variable rate debt through December 31, 2010, through the use of variable to fixed interest rate swaps, the majority of which mature in years 2009 through 2012. To the extent eligible, our interest rate swaps have been designed as cash flow hedges, and changes in fair value are recorded in OCI to the extent they are effective.

Our CCFC Refinancing reduced our exposure to fluctuating interest rates by refinancing approximately $1.1 billion in variable interest rate debt (including our CCFCP Preferred Shares) with $1.0 billion of fixed interest rate debt. The following table summarizes the contract terms as well as the fair values of our significant financial instruments exposed to interest rate risk as of June 30, 2009. All outstanding balances and fair market values are shown gross of applicable premium or discount, if any (in millions):

	2009	2010	2011	2012	2013	Thereafter	Total	Fair Value June 30, 2009
Debt by Maturity Date:								
Fixed Rate	$ 93	$ 207	$ 71	$ 21	$ 24	$ 1,131	$ 1,547	$ 1,481
Average Interest Rate	5.7%	6.5%	6.9%	9.6%	9.6%	7.9%		
Variable Rate	$ 306	$ 184	$ 974	$ 212	$ 76	$ 6,635	$ 8,387	$ 7,664
Average Interest Rate(1)	8.9%	3.9%	3.9%	4.7%	4.8%	6.8%		

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(1) Projection based upon anticipated LIBOR rates.

New Accounting Requirements and Disclosures

See Note 1 of the Notes to Consolidated Condensed Financial Statements for a discussion of new accounting requirements and disclosures.

Item 3. *Quantitative and Qualitative Disclosures About Market Risk*

See "Risk Management and Commodity Accounting" in Item 2.

Item 4. *Controls and Procedures*

Disclosure Controls and Procedures

We maintain disclosure controls and procedures that are designed to ensure that information required to be disclosed in our Exchange Act reports is recorded, processed, summarized, and reported within the time periods specified in the SEC's rules and forms, and that such information is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate, to allow timely decisions regarding required financial disclosure.

As of the end of the period covered by this Report, we carried out an evaluation, under the supervision and with the participation of our management, including our Chief Executive Officer and Chief Financial Officer, of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Rule 13a-15 of the Exchange Act. Based upon, and as of the date of this evaluation, the Chief Executive Officer and the Chief Financial Officer concluded that our disclosure controls and procedures were effective.

Changes in Internal Control Over Financial Reporting

During the second quarter of 2009, there were no changes in our internal control over financial reporting that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

PART II — OTHER INFORMATION

Item 1. *Legal Proceedings*

See Note 12 of the Notes to Consolidated Condensed Financial Statements for a description of our legal proceedings.

Item 1A. *Risk Factors*

Various risk factors could have a negative effect on our business, financial position, cash flows and results of operations. These include the following risk factors, in addition to the risk factors set forth in "Item 1A. Risk Factors" in our 2008 Form 10-K:

Existing and future anticipated GHG/Carbon legislation could adversely affect our operations.

Environmental laws and regulations have generally become more stringent over time, and this trend is likely to continue. In particular, there is growing likelihood that carbon tax or limits on carbon, CO_2 and other GHG emissions will be implemented at the federal or expanded at the state or regional levels.

In 2009, ten states in the northeast began the compliance period of a cap-and-trade program, RGGI, to regulate CO_2 emissions from power plants. California is in the process of creating implementation plans for Assembly Bill 32 which places a statewide cap on GHG emissions and requires the state to return to 1990 emission levels by 2020.

In 2008, there were several bills introduced in the U.S. Congress concerning climate change, and on June 26, 2009, the House of Representatives passed The American Clean Energy and Security Act of 2009, a climate change and clean energy bill, which, among other provisions, would establish an economy-wide carbon cap-and-trade program and set carbon emission reduction targets in several sectors of the economy, including the electricity sector. For the electricity sector, 2012 is set as the initial year for compliance.

If this bill were to become law, we would have the obligation to obtain emissions allowances for the operation of our fossil-fuel power plants. While we expect the costs to acquire allowances to be a factor that will impact market price, there can be no assurance that market price will fully reflect these costs which could adversely affect our Commodity Margin. With respect to our existing long-term steam and power contracts under which we would not be able to recover costs to acquire allowances from our customers, the bill allocates a pool of free allowances to generators with qualifying contracts to mitigate such costs. However, there can be no assurance there will be a sufficient number of free allowances in the pool to fully cover emissions related to generation under such contracts which could adversely impact our Commodity Margin.

To become law, this bill must also, among other things, be passed by the Senate, which has commenced hearings on the climate change issue; however, it has not yet introduced any legislation. Although we cannot predict the effect and ultimate content of final climate change legislation and regulations, if any, on our business, we continue to expect climate change legislation efforts to proceed at the federal level, and that proposed legislation will take the form of a cap-and-trade program, although it is possible that legislation may take other forms, such as a carbon tax on each unit of CO_2 or GHG emitted in excess of mandated limits. As a result of requirements for GHG emissions reduction, we could be required under any climate change legislation or related regulations ultimately enacted to purchase allowances or offsets to emit GHGs or other regulated pollutants or to pay taxes on such emissions. These requirements, as well as the possibility that market or contract prices will not fully reflect costs of compliance, or that we may not be able to obtain free allowances or recoup our costs to obtain allowances or to reduce emissions, could have a material impact on our business or results of operations.

Claims that some geothermal plants cause increased risk of seismic activity could delay or increase the cost of further development at The Geysers.

In 2009, as part of a joint private and federally-funded geothermal technology research project, a company unrelated to us commenced deepening an existing geothermal well on a property neighboring our Geysers Assets in northern California, and reportedly is attempting to drill into the hot, low or non-permeable base rock that underlies the existing geothermal steam reservoir at The Geysers to engineer or create a "multilayered heat extraction system" below the reservoir by injecting water under very high pressure, fracturing the rock. While there is general agreement that the operation of certain geothermal plants may cause low level seismic activity, the fracturing of deep bedrock caused by the multilayered heat extraction system is believed to create a greater risk of more serious seismic activity and has spawned public and political concern due to this risk. As a consequence, in June 2009, the Department of Energy began requiring all geothermal research grant applicants to comply with a published seismic mitigation protocol, and, in July 2009, the Department of Energy temporarily halted funding of its portion of that research project pending further seismicity studies. Although our geothermal operations do not include attempts to engineer or create new reservoirs from hot, low or non-permeable rock, the public concern regarding induced seismicity from geothermal operations could delay or otherwise adversely impact our Department of Energy grant applications. In addition, it is possible that government agencies will seek to more stringently regulate the exploration, development and operation of geothermal facilities, including operations of our Geysers Assets, in order to mitigate induced seismicity resulting from geothermal operations, or that operators of geothermal power plants could be subject to property damage claims resulting from increased seismic activity. Any of these events could delay or increase the cost of any further development of our Geysers Assets.

Item 2. *Unregistered Sales of Equity Securities and Use of Proceeds*

Repurchase of Equity Securities. Upon vesting of restricted stock awarded by us to employees, we withhold shares to cover employees' tax withholding obligations, other than for employees who have chosen to make tax withholding payments in cash. As set forth in the table below, during the second quarter of 2009, we withheld a total of 55 shares in the indicated months. These were the only repurchases of equity securities made by us during this period. We do not have a stock repurchase program.

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid Per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs
April	—	$ —	—	n/a
May	55	$ 12.75	—	n/a
June	—	$ —	—	n/a
Total	55	$ 12.75	—	n/a

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

Calpine shareholders voted on three items at our 2009 Annual Meeting of Shareholders held on May 7, 2009:

- To elect nine directors.
- To amend Section 3.2 of our Amended and Restated Bylaws to permit the size of the Board of Directors to be determined by the Board from time to time, within a range of a minimum of five directors up to a maximum of 11 directors.
- To ratify the appointment of PricewaterhouseCoopers LLP to serve as our independent public accounting firm for the 2009 fiscal year.

There were 428,668,995 shares of common stock entitled to vote at the meeting and a total of 376,771,571 shares (approximately 87.89%) were represented at the meeting.

The individuals named below were elected to serve on our Board of Directors until the 2010 annual meeting of shareholders and until their successors have been elected and qualified:

Name	Votes For	Votes Withheld
Frank Cassidy	342,220,536	34,551,035
Jack A. Fusco	371,433,445	5,338,126
Robert C. Hinckley	371,333,331	5,438,240
David C. Merritt	371,387,685	5,383,886
W. Benjamin Moreland	371,389,588	5,381,983
Robert A. Mosbacher, Jr.	373,723,212	3,048,359
Denise M. O’Leary	338,042,724	38,728,847
William J. Patterson	369,434,311	7,337,260
J. Stuart Ryan	334,906,856	41,864,715

The proposal to amend Section 3.2 of our Amended and Restated Bylaws was approved with 372,414,673 shares voting for, 4,079,012 shares voting against, 277,886 shares abstaining and no broker non-votes.

The proposal to ratify the appointment of PricewaterhouseCoopers LLP to serve as our independent public accounting firm for the 2009 fiscal year was approved with 374,404,542 shares voting for, 1,709,461 shares voting against, 657,567 shares abstaining and no broker non-votes.

Item 6. ***Exhibits***

The following exhibits are filed herewith unless otherwise indicated:

EXHIBIT INDEX

Exhibit Number	Description
1.1	Underwriting Agreement, dated April 23, 2009, among Calpine Corporation, the selling stockholder named therein and Morgan Stanley & Co. Incorporated, the underwriter named therein (incorporated by reference to Exhibit 1.1 to our Current Report on Form 8-K/A filed with the SEC on April 24, 2009).
3.1	Amended and Restated Certificate of Incorporation of the Company, as amended (incorporated by reference to Exhibit 3.1 to the Company’s Current Report on Form 8-K filed with the SEC on February 1, 2008).
3.2	Amended and Restated Bylaws of the Company (as amended through May 7, 2009).*
4.1	Indenture, dated May 19, 2009, among Calpine Construction Finance Company, L.P. and CCFC Finance Corp., as Issuers, the Guarantors named therein, and Wilmington Trust Company, as Trustee, including the form of the Notes (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K filed with the SEC on May 22, 2009).
31.1	Certification of the Chief Executive Officer Pursuant to Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*
31.2	Certification of the Chief Financial Officer Pursuant to Rule 13a-14(a) or Rule 15d-14(a) under the Securities Exchange Act of 1934, as Adopted Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*
32.1	Certification of Chief Executive Officer and Chief Financial Officer Pursuant to 18 U.S.C. Section 1350, as Adopted Pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.*

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* Filed herewith.

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

By: /s/ ZAMIR RAUF

Zamir Rauf
Executive Vice President and
Chief Financial Officer

Date: July 30, 2009

By: /s/ JIM D. DEIDIKER

Jim D. Deidiker
Senior Vice President and
Chief Accounting Officer

Date: July 30, 2009

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* Filed herewith.

AMENDED AND RESTATED BYLAWS

OF

CALPINE CORPORATION

(a Delaware corporation)

As amended through May 7, 2009

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(As amended through May 7, 2009)

ARTICLE I

OFFICES

Section 1.1 Location. The address of the registered office of the Corporation in the State of Delaware and the name of the registered agent at such address shall be as specified in the Certificate of Incorporation or, if subsequently changed, as specified in the most recent Statement of Change filed pursuant to law. The Corporation may also have other offices at such places within or without the State of Delaware as the Board of Directors may from time to time designate or the business of the Corporation may require.

Section 1.2 Change of Location. In the manner permitted by law, the Board of Directors or the registered agent may change the address of the Corporation's registered office in the State of Delaware and the Board of Directors may make, revoke or change the designation of the registered agent.

ARTICLE II

MEETINGS OF STOCKHOLDERS

Section 2.1 Annual Meeting. The annual meeting of the stockholders of the Corporation for the election of Directors and for the transaction of such other business as may properly come before the meeting shall be held at the registered office of the Corporation, or at such other place within or without the State of Delaware as the Board of Directors may fix by resolution or as set forth in the notice of the meeting.

Section 2.2 Special Meetings. Special meetings of stockholders, unless otherwise prescribed by law, may only be called by the Chairman of the Board of Directors, by order of a majority of the whole Board of Directors or by holders of common stock who hold a majority of the outstanding common stock entitled to vote generally in the election of Directors. Stock ownership for these purposes may be evidenced in any manner prescribed by Rule 14a-8(b)(2) under the Securities Exchange Act of 1934, as amended (the "Exchange Act"). Special meetings of stockholders shall be held at such time and any such place, within or without the State of Delaware, as shall be designated in the notice of meeting; provided, however, that any special meeting called by stockholders pursuant to this Section 2.2 shall comply with the notice, administrative and other requirements of Section 2.9 in addition to the other requirements of this Article II.

Section 2.3 List of Stockholders Entitled to Vote. The officer who has charge of the stock ledger of the Corporation shall prepare and make, or cause to be prepared and made, at least ten days before every meeting of stockholders, a complete list, based upon the record date for such meeting determined pursuant to Section 5.8, of the stockholders entitled to vote at the meeting, arranged in alphabetical order, and showing the address of each stockholder and the number of shares registered in the name of each stockholder. Such list shall be open to the examination of any stockholder, for any purpose germane to the meeting, during ordinary business hours, for a period of at least ten days prior to the meeting at the Corporation's principal place of business. The list also shall be produced and kept at the time and place of the meeting during the whole time thereof, and may be inspected by any stockholder who is present.

The stock ledger shall be the only evidence as to who are the stockholders entitled to examine the stock ledger, the list of stockholders entitled to vote at any meeting, or to inspect the books of the Corporation, or to vote in person or by proxy at any meeting of stockholders.

Section 2.4 Notice of Meetings to Stockholders. Written notice of each annual and special meeting of stockholders, other than any meeting the giving of notice of which is otherwise prescribed by law, stating the place, date and hour of the meeting, and, in the case of a special meeting, the purpose or purposes for which the meeting is called, shall be delivered or mailed, in writing, at least ten but not more than sixty days before the date of such meeting, to each stockholder entitled to vote thereat. If mailed, such notice shall be deposited in the United States mail, postage prepaid, directed to such stockholder at the address as the same appears on the records of the Corporation. Notice given by electronic transmission shall be effective (A) if by facsimile, when faxed to a number where the stockholder has consented to receive notice; (B) if by electronic mail, when mailed electronically to an electronic mail address at which the stockholder has consented to receive such notice; (C) if by posting on an electronic network together with a separate notice of such posting, upon the later to occur of (1) the posting or (2) the giving of separate notice of the posting; or (D) if by other form of electronic communication, when directed to the stockholder in the manner consented to by the stockholder. An affidavit of the Secretary, an Assistant Secretary or the transfer agent of the Corporation that notice has been duly given shall be evidence of the facts stated therein.

Section 2.5 Adjourned Meetings and Notice Thereof. Any meeting of stockholders may be adjourned to another time or place, and the Corporation may transact at any adjourned meeting any business which might have been transacted at the original meeting. Notice need not be given of the adjourned meeting if the time and place thereof are announced at the meeting at which the adjournment is taken, unless (a) any adjournment caused the original meeting to be adjourned for more than thirty days after the date originally fixed therefor, or (b) a new record date is fixed for the adjourned meeting. If notice of an adjourned meeting is given, such notice shall be given to each stockholder of record entitled to vote at the adjourned meeting in the manner prescribed in Section 2.4 for the giving of notice of meetings.

Section 2.6 Quorum. At any meeting of stockholders, except as otherwise expressly required by law or by the Certificate of Incorporation, the holders of record of at least a majority of the outstanding shares of capital stock entitled to vote or act at such meeting shall be present or represented by proxy in order to constitute a quorum for the transaction of any business, but less than a quorum shall have power to adjourn any meeting until a quorum shall be present. When a quorum is once present to organize a meeting, the quorum cannot be destroyed by the subsequent withdrawal or revocation of the proxy of any stockholder. Shares of capital stock owned by the Corporation or by another corporation, if a majority of the shares of such other corporation entitled to vote in the election of Directors is held by the Corporation, shall not be counted for quorum purposes or entitled to vote. Notwithstanding the foregoing, when specified business is to be voted on by a class or series voting separately as a class or series, the holders of a majority of the voting power of the shares of such class or series shall constitute a quorum for the transaction of such business for the purposes of taking action on such business.

Section 2.7 Voting. At any meeting of stockholders, each stockholder holding, as of the record date, shares of stock entitled to be voted on any matter at such meeting shall have one vote on each such matter submitted to vote at such meeting for each such share of stock held by such stockholder, as of the record date, as shown by the list of stockholders entitled to vote at the meeting, unless the Certificate of Incorporation provides for more or less than one vote for any share, on any matter, in which case every reference in these Bylaws to a majority or other proportion of stock shall refer to such majority or other proportion of the votes of such stock.

Each stockholder entitled to vote at a meeting of stockholders may authorize another person or persons to act for such stockholder by proxy, provided that no proxy shall be voted or acted upon after three years from its date, unless the proxy provides for a longer period. A duly executed proxy shall be irrevocable if it states that it is irrevocable and if, and only so long as, it is coupled with an interest, whether in the stock itself or in the Corporation generally, sufficient in law to support an irrevocable power. Such proxy must be filed with the Secretary of the Corporation or the Secretary's representative, or otherwise delivered telephonically or electronically as set forth in the applicable proxy statement, at or before the time of the meeting.

The Board of Directors, the Chairman of the Board, the Chief Executive Officer, or the person presiding at a meeting of stockholders may appoint one or more persons to act as inspectors of voting at any meeting with respect to any matter to be submitted to a vote of stockholders at such meeting, with such powers and duties, not inconsistent with applicable law, as may be appropriate.

Section 2.8 Action by Consent of Stockholders. Any action required or permitted to be taken by the stockholders of the Company must be effected at a duly called annual or special meeting of the Company and may not be effected by any consent in writing of such stockholders.

Section 2.9 Nature of Business at Meetings of Stockholders; Notice Procedures. No business may be transacted at any meeting of stockholders, other than business that is either (a) specified in the notice of meeting (or any supplement thereto) given by or at the direction of the Board of Directors (or any duly authorized committee thereof), (b) otherwise properly brought before the annual meeting by or at the direction of the Board of Directors (or any duly authorized committee thereof), or (c) otherwise properly brought before the meeting by any stockholder of the Corporation (i) who is a stockholder of record on the date of the giving of the notice provided for in this Section 2.9 and on the record date for the determination of stockholders entitled to notice of and to vote at such meeting and (ii) who complies with the notice procedures set forth in this Section 2.9.

In addition to any other applicable requirements, for business to be properly brought before any meeting of stockholders by a stockholder, such stockholder must have given timely notice thereof in proper written form to the Secretary of the Corporation.

To be timely, a stockholder's notice to the Secretary must be delivered to or mailed and received at the principal executive offices of the Corporation not less than ninety days nor more than one hundred twenty days prior to the anniversary date of the immediately preceding annual meeting of stockholders; provided, however, that in the event that the annual meeting is called for a date that is not within thirty days before or after such anniversary date, notice by the stockholder in order to be timely must be so received not later than the close of business on the tenth day following the day on which such notice of the date of the annual meeting was mailed or such public disclosure of the date of the annual meeting was made, whichever first occurs. Notwithstanding the previous sentence, for purposes of determining whether a stockholder's notice shall have been timely received for the annual meeting of stockholders in 2009, a stockholder's notice must have been received not later than February 1, 2009 nor earlier than January 1, 2009. Subject to the information requirements of this Section 2.9, any special meetings called by stockholders pursuant to Section 2.2 shall be preceded by a notice of such stockholders to the Secretary, to be delivered to or mailed and received at the principal executive offices of the Corporation, not less than ninety days nor more than one hundred twenty days prior to the date specified in such notice for such special meeting. The location of such meeting shall be at the discretion of the Board of Directors.

To be in proper written form, a stockholder's notice to the Secretary must set forth as to each matter such stockholder proposes to bring before the meeting (i) a brief description of the business desired to be brought before the meeting and the reasons for conducting such business at the meeting, (ii) the name and record address of such stockholder, (iii) the class or series and number of shares of capital stock of the Corporation which are owned beneficially or of record by such stockholder, (iv) a description of all arrangements or understandings between such stockholder and any other person or persons (including their names) in connection with the proposal of such business by such stockholder and any material interest of such stockholder in such business and (v) a representation that such stockholder intends to appear in person or by proxy at the meeting to bring such business before the meeting.

No business shall be conducted at any meeting of stockholders except business brought before the meeting in accordance with the procedures set forth in this Section 2.9; provided, however, that, once business has been properly brought before the meeting in accordance with such procedures, nothing in this Section 2.9 shall be deemed to preclude discussion by any stockholder of any such business. If the chairman of a meeting determines that business was not properly brought before the meeting in accordance with the foregoing procedures, the chairman shall declare to the meeting that the business was not properly brought before the meeting and such business shall not be transacted. Notwithstanding the foregoing provisions of this Section 2.9, unless otherwise required by law, if the stockholder (or a qualified representative of the stockholder) does not appear at the annual or special meeting of stockholders of the Corporation to present a nomination or proposed business, such nomination shall be disregarded and such proposed business shall not be transacted, notwithstanding that proxies in respect of such vote may have been received by the Corporation. For purposes of this

Section 2.9, to be considered a qualified representative of the stockholder, a person must be a duly authorized officer, manager or partner of such stockholder or must be authorized by a writing executed by such stockholder or an electronic transmission delivered by such stockholder to act for such stockholder as proxy at the meeting of stockholders and such person must produce such writing or electronic transmission, or a reliable reproduction of the writing or electronic transmission, at the meeting of stockholders.

The Board of Directors may adopt by resolution such rules and regulations for the conduct of the meeting of stockholders as it shall deem appropriate. The Chairman of the Board shall preside at all meetings of the stockholders. If the Chairman of the Board is not present, the Chief Executive Officer or the President shall preside over such meeting, and, if the Chief Executive Officer or the President is not present at the meeting, a majority of the Board of Directors present at such meeting shall elect one of their members to so preside.

Notwithstanding anything in this Section 2.9 to the contrary, only persons nominated for election as a Director at an annual or special meeting pursuant to Section 3.4 will be considered for election at such meeting.

ARTICLE III

BOARD OF DIRECTORS

Section 3.1 General Powers. The property, business and affairs of the Corporation shall be managed by or under the direction of a Board of Directors. The Board of Directors may exercise all such powers of the Corporation and have such authority and do all such lawful acts and things as are permitted by law, the Certificate of Incorporation or these Bylaws.

Section 3.2 Number of Directors. The Board of Directors shall consist of not less than five (5) nor more than eleven (11) Directors. Subject to the foregoing sentence, the specific number of Directors constituting the Board of Directors shall be determined by resolution of the Board of Directors, but no decrease in the number of Directors shall have the effect of shortening the term of any incumbent Director.

Section 3.3 Qualification. Directors must be natural persons but need not be stockholders of the Corporation. Directors who willfully neglect or refuse to produce a list of stockholders entitled to vote at any meeting for the election of Directors shall be ineligible for election to any office at such meeting.

Section 3.4 Election.

(a) The Corporation will hold its first annual meeting of stockholders following the effectiveness of these Amended and Restated Bylaws on a date to be determined by the Board of Directors during calendar year 2009. Prior to such time, the Directors of the Corporation shall be those holding office at the time of the effectiveness of these Amended and Restated Bylaws or those appointed by the Board to fill any vacancies in accordance with Section 3.7 hereof. Except as otherwise provided by law, the Certificate of Incorporation or these Bylaws, after the first meeting of the Corporation at which Directors are elected, Directors of the Corporation shall be elected in each year at the annual meeting of stockholders, or at a special meeting in lieu of the annual meeting called for such purpose, by the vote of the plurality of the votes cast at any meeting for the election of Directors at which a quorum is present.

(b) Only persons who are nominated in accordance with the following procedures shall be eligible for election as Directors of the Corporation, except as may be otherwise provided in the Certificate of Incorporation with respect to the right of holders of preferred stock of the Corporation to nominate and elect a specified number of Directors in certain circumstances. Nominations of persons for election to the Board of Directors may be made at any annual meeting of stockholders, or at any special meeting of stockholders called for the purpose of electing Directors, (a) by or at the direction of the Board of Directors (or any duly authorized committee thereof) or (b) by any stockholder of the Corporation (i) who is a stockholder of record on the date of the giving of the notice provided for in this Section 3.4(b) and on the record date for the determination of stockholders entitled to notice of and to vote at such meeting and (ii) who complies with the notice procedures set forth in this Section 3.4(b).

In addition to any other applicable requirements, for a nomination to be made by a stockholder, such stockholder must have given timely notice thereof in proper written form to the Secretary of the Corporation.

To be timely, a stockholder's notice to the Secretary must be delivered to or mailed and received at the principal executive offices of the Corporation (a) in the case of an annual meeting, not less than ninety days nor more than one hundred twenty days prior to the anniversary date of the immediately preceding annual meeting of stockholders; provided, however, that in the event that the annual meeting is called for a date that is not within thirty days before or after such anniversary date, notice by the stockholder in order to be timely must be so received not later than the close of business on the tenth day following the day on which such notice of the date of the annual meeting was mailed or such public disclosure of the date of the annual meeting was made, whichever first occurs; provided further that for purposes of determining whether a stockholder's notice shall have been timely received for the annual meeting of stockholders in 2009, a stockholder's notice must have been received not later than February 1, 2009 nor earlier than January 1, 2009; and (b) in the case of a special meeting of stockholders called for the purpose of electing Directors, not later than the close of business on the tenth day following the day on which notice of the date of the special meeting was mailed or public disclosure of the date of the special meeting was made, whichever first occurs.

To be in proper written form, a stockholder's notice to the Secretary must set forth (a) as to each person whom the stockholder proposes to nominate for election as a Director (i) the name, age, business address and residence address of the person, (ii) the principal occupation or employment of the person, (iii) the class or series and number of shares of capital stock of the Corporation which are owned beneficially or of record by the person and (iv) any other information relating to the person that would be required to be disclosed in a proxy statement or other filings required to be made in connection with solicitations of proxies for election of Directors pursuant to Section 14 of the Exchange Act, and the rules and regulations promulgated thereunder; and (b) as to the stockholder giving the notice (i) the name and record address of such stockholder, (ii) the class or series and number of shares of capital stock of the Corporation which are owned beneficially or of record by such stockholder, (iii) a description of all arrangements or understandings between such stockholder and each proposed nominee and any other person or persons (including their names) pursuant to which the nomination(s) are to be made by such stockholder, (iv) a representation that such stockholder intends to appear in person or by proxy at the meeting to nominate the persons named in its notice and (v) any other information relating to such stockholder that would be required to be disclosed in a proxy statement or other filings required to be made in connection with solicitations of proxies for election of Directors pursuant to Section 14 of the Exchange Act and the rules and regulations promulgated thereunder. Such notice must be accompanied by a written consent of each proposed nominee to being named as a nominee and to serve as a Director if elected.

No person shall be eligible for election as a Director of the Corporation unless nominated in accordance with the procedures set forth in this Section 3.4(b). If the chairman of the meeting determines that a nomination was not made in accordance with the foregoing procedures, the chairman shall declare to the meeting that the nomination was defective and such defective nomination shall be disregarded.

Section 3.5 Term. Each Director shall hold office until such Director's successor is duly elected and qualified, except in the event of the earlier termination of such Director's term of office by reason of death, resignation, removal or other reason.

Section 3.6 Resignation and Removal. Any Director may resign at any time upon written notice to the Board of Directors, the Chairman of the Board, the Chief Executive Officer or the Secretary. The resignation of any Director shall take effect upon receipt of notice thereof or at such later time as shall be specified in such notice, and unless otherwise specified therein, the acceptance of such resignation shall not be necessary to make it effective. Any Director or the entire Board of Directors may be removed, with or without cause, by the holders of a majority of the shares then entitled to vote at an election of Directors.

Section 3.7 Vacancies. Vacancies in the Board of Directors and newly created Directorships resulting from any increase in the authorized number of Directors shall be filled by a majority of the Directors then in office, though less than a quorum, or by a sole remaining Director.

If one or more Directors shall resign (or are removed) from the Board of Directors effective at a future date, a majority of the Directors then in office, but not including those who have so resigned at a future date, shall have power to fill such vacancy or vacancies, the vote thereon to take effect and the vacancy to be filled when such resignation or resignations shall become effective, and each Director so chosen shall hold office as provided in this Section 3.7 in the filling of other vacancies.

Each Director chosen to fill a vacancy on the Board of Directors shall hold office until the next annual election of Directors and until such Director's successor shall be elected and qualified.

Section 3.8 Quorum and Voting. Unless the Certificate of Incorporation provides otherwise, at all meetings of the Board of Directors a majority of the total number of Directors shall be present to constitute a quorum for the transaction of business. A Director interested in a contract or transaction may be counted in determining the presence of a quorum at a meeting of the Board of Directors which authorizes the contract or transaction. In the absence of a quorum, a majority of the Directors present may adjourn the meeting until a quorum shall be present.

Unless the Certificate of Incorporation provides otherwise, members of the Board of Directors or any committee designated by the Board of Directors may participate in a meeting of the Board of Directors or such committee by means of a conference telephone or similar communications equipment by means of which all persons participating in the meeting can hear each other, and participation in such a meeting shall constitute presence in person at such meeting.

The vote of the majority of the Directors present at a meeting at which a quorum is present shall be the act of the Board of Directors unless the Certificate of Incorporation or these Bylaws shall require a vote of a greater number.

Section 3.9 Regulations. The Board of Directors may adopt such rules and regulations for the conduct of the business and management of the Corporation, not inconsistent with law or the Certificate of Incorporation or these Bylaws, as the Board of Directors may deem proper. The Board of Directors may hold its meetings and cause the books and records of the Corporation to be kept at such place or places within or without the State of Delaware as the Board of Directors may from time to time determine. A member of the Board of Directors, or a member of any committee designated by the Board of Directors shall, in the performance of such member's duties, be fully protected in relying in good faith upon the books of account or reports made to the Corporation by any of its officers, by an independent certified public accountant, or by an appraiser selected with reasonable care by the Board of Directors or any committee of the Board of Directors or in relying in good faith upon other records of the Corporation.

Section 3.10 Annual Meeting. An annual meeting of the Board of Directors shall be called and held for the purpose of organization, election of officers and transaction of any other business. If such meeting is held promptly after and at the place specified for the annual meeting of stockholders, no notice of the annual meeting of the Board of Directors need be given. Otherwise, such annual meeting shall be held at such time (not more than thirty days after the annual meeting of stockholders) and place as may be specified in a notice of the meeting.

Section 3.11 Regular Meetings. Regular meetings of the Board of Directors shall be held at the time and place, within or without the State of Delaware, as shall from time to time be determined by the Board of Directors. After there has been such determination and notice thereof has been given to each member of the Board of Directors, no further notice shall be required for any such regular meeting. Except as otherwise provided by law, any business may be transacted at any regular meeting.

Section 3.12 Special Meetings. Special meetings of the Board of Directors may, unless otherwise prescribed by law, be called from time to time by the Chairman of the Board, and shall be called by the Chairman of the Board, the Chief Executive Officer or the Secretary upon the written request of a majority of the whole Board of Directors directed to the Chairman of the Board, the Chief Executive Officer or the Secretary. Except as provided below, notice of any special meeting of the Board of Directors, stating the time, place and purpose of such special meeting, shall be given to each Director.

Section 3.13 Notice of Meetings; Waiver of Notice. Notice of any meeting of the Board of Directors shall be deemed to be duly given to a Director (i) if mailed and addressed to such Director at the address as it appears upon the books of the Corporation, or at the address last made known in writing to the Corporation by such Director as the address to which such notices are to be sent, at least five days before the day on which such meeting is to be held, or (ii) if sent to such Director at such address by telegraph, telex, telecopy, e mail, cable, radio or wireless not later than 24 hours before the time when such meeting is to be held, or (iii) if delivered to such Director personally or orally, by telephone or otherwise, not later than 24 hours before the time when such meeting is to be held. Each such notice shall state the time and place of the meeting and the purposes thereof.

Notice of any meeting of the Board of Directors need not be given to any Director if waived by such Director in writing (or by telegram, cable, radio or wireless and confirmed in writing) whether before or after the holding of such meeting, or if such Director is present at such meeting. Any meeting of the Board of Directors shall be a duly constituted meeting without any notice thereof having been given if all Directors then in office shall be present thereat.

Section 3.14 Committees of Directors. The Board of Directors may, by resolution or resolutions passed by a majority of the Board of Directors, designate one or more committees, each committee to consist of one or more of the Directors of the Corporation.

Except as hereinafter provided, vacancies in membership of any committee shall be filled by the vote of a majority of the Board of Directors. The Board of Directors may designate one or more Directors as alternate members of any committee, who may replace any absent or disqualified member at any meeting of the committee. In the absence or disqualification of any member of a committee (and the alternate appointed pursuant to the immediately preceding sentence, if any), the member or members thereof present at any meeting and not disqualified from voting, whether or not constituting a quorum, may unanimously appoint another member of the Board of Directors to act at the meeting in the place of any such absent or disqualified member. Members of a committee shall hold office for such period as may be fixed by a resolution adopted by a majority of the Board of Directors, subject, however, to removal at any time by the vote of a majority of the Board of Directors.

Section 3.15 Powers and Duties of Committees. Any committee, to the extent provided in the resolution or resolutions creating such committee, shall have and may exercise all the powers and authority of the Board of Directors in the management of the business and affairs of the Corporation, and may authorize the seal of the Corporation to be affixed to all papers which may require it. No such committee shall have the power or authority with regard to amending the Certificate of Incorporation, adopting an agreement of merger or consolidation, recommending to the stockholders the sale, lease or exchange of all or substantially all of the Corporation's property and assets, recommending to the stockholders a dissolution of the Corporation or a revocation of a dissolution, or amending or repealing the Bylaws. The Corporation hereby expressly elects to be governed by Section 141(c)(2) of the Delaware General Corporation Law.

Each committee may adopt its own rules of procedure and may meet at stated times or on such notice as such committee may determine. Except as otherwise permitted by these Bylaws, each committee shall keep regular minutes of its proceedings and report the same to the Board of Directors when required.

Section 3.16 Compensation of Directors. Each Director shall be entitled to receive for attendance at each meeting of the Board of Directors or any duly constituted committee thereof which such Director attends, such fee as is fixed by the Board and in connection therewith shall be reimbursed by the Corporation for travel expenses. The fees to such Directors may be fixed in unequal amounts among them, taking into account their respective relationships to the Corporation in other capacities. These provisions shall not be construed to preclude any Director from receiving compensation in serving the Corporation in any other capacity.

Section 3.17 Action Without Meeting. Unless otherwise restricted by the Certificate of Incorporation, any action required or permitted to be taken at any meeting of the Board of Directors or of any committee thereof may be taken without a meeting if all of the members of the Board of Directors or of such committee consent thereto in writing or by electronic transmission, as the case may be, and such written consent is filed with the minutes of proceedings of the Board of Directors or such committee.

ARTICLE IV

OFFICERS

Section 4.1 Principal Officers. The principal officers of the Corporation shall be elected by the Board of Directors and shall include a Chairman of the Board, a Chief Executive Officer (who may also be the President), a Chief Financial Officer and a Secretary and may, at the discretion of the Board of Directors, also include a Vice Chairman of the Board, a President, one or more Vice Presidents, a Treasurer and a Controller. All officers chosen by the Board of Directors shall each have such powers and duties as generally pertain to their respective offices, subject to the specific provisions of this Article IV. Such officers shall also have powers and duties as from time to time may be conferred by the Board of Directors or by any committee thereof. Except as otherwise provided in the Certificate of Incorporation or these Bylaws, one person may hold the offices and perform the duties of any two or more of said principal offices. None of the principal officers need be Directors of the Corporation.

Section 4.2 Election of Principal Officers; Term of Office. The principal officers of the Corporation shall be elected annually by the Directors at such annual meeting of the Board of Directors. Failure to elect any principal officer annually shall not dissolve the Corporation.

If the Board of Directors shall fail to fill any principal office at an annual meeting, or if any vacancy in any principal office shall occur, or if any principal office shall be newly created, such principal office may be filled at any regular or special meeting of the Board of Directors.

Each principal officer shall hold office until such officer's successor is duly elected and qualified, or until such officer's earlier death, resignation or removal.

Section 4.3 Subordinate Officers; Agents and Employees. In addition to the principal officers, the Corporation may have one or more Assistant Treasurers, Assistant Secretaries, and such other subordinate officers, agents and employees as the Board of Directors may deem advisable, each of whom shall hold office for such period and have such authority and perform such duties as the Board of Directors, the Chairman of the Board, the Chief Executive Officer, or any officer designated by the Board of Directors, may from time to time determine. The Board of Directors at any time may appoint and remove, or may delegate to any principal officer the power to appoint and to remove, any subordinate officer, agent or employee of the Corporation.

Section 4.4 Delegation of Duties of Officers. The Board of Directors may delegate the duties and powers of any officer of the Corporation to any other officer or to any Director for a specified period of time for any reason that the Board of Directors may deem sufficient.

Section 4.5 Removal of Officers. Any officer of the Corporation removed, with or without cause, by resolution adopted by a majority of the Directors then in office at any regular or special meeting of the Board of Directors or by a written consent signed by all of the Directors then in office. No elected officer shall have any contractual rights against the Corporation for compensation by virtue of such election beyond the date of the election of such officer's successor, death, resignation or removal, whichever event shall first occur, except as otherwise provided in an employment contract or an employee plan.

Section 4.6 Resignations. Any officer may resign at any time by giving written notice of resignation to the Board of Directors, to the Chairman of the Board, to the Chief Executive Officer or to the Secretary. Any such resignation shall take effect upon receipt of such notice or at any later time specified therein. Unless otherwise specified in the notice, the acceptance of a resignation shall not be necessary to make the resignation effective.

Section 4.7 Chairman of the Board. The Chairman of the Board shall preside at all meetings of stockholders and of the Board of Directors at which the Chairman of the Board is present. The Chairman of the Board shall have such other powers and perform such other duties as may be assigned from time to time by the Board of Directors.

Section 4.8 Chief Executive Officer. The Chief Executive Officer shall, in the absence of the Chairman of the Board, preside at all meetings of the stockholders and of the Board of Directors at which the Chief Executive Officer is present. The Chief Executive Officer shall be the chief executive officer of the Corporation and shall have general supervision over the business and affairs of the Corporation and shall be responsible for carrying out the policies and objectives established by the Board of Directors. The Chief Executive Officer shall have all powers and duties usually incident to the office of the Chief Executive Officer, except as specifically limited by a resolution of the Board of Directors. The Chief Executive Officer shall have such other powers and perform such other duties as may be assigned from time to time by the Board of Directors and may be designated as President as well as Chief Executive Officer.

Section 4.9 President. The President shall, in the absence of the Chairman of the Board or the Chief Executive Officer, preside at all meetings of the stockholders and of the Board of Directors at which the President is present. In the absence of a Chief Executive Officer, the President shall be the chief executive officer of the Corporation and shall have general supervision over the business and affairs of the Corporation and shall be responsible for carrying out the policies and objectives established by the Board of Directors. The President shall have all powers and duties usually incident to the office of the President, except as specifically limited by a resolution of the Board of Directors. The President shall have such other powers and perform such other duties as may be assigned from time to time by the Board of Directors.

Section 4.10 Chief Financial Officer. The Chief Financial Officer shall be responsible for all functions and duties related to the financial affairs of the Corporation, and may also serve as the Treasurer of the Corporation and the Controller of the Corporation. The Chief Financial Officer may, in the discretion of the Board of Directors, be the chief accounting officer of the Corporation and shall have supervision over the maintenance and custody of the accounting operations of the Corporation. The Chief Financial Officer shall:

(a) Keep and maintain, or cause to be kept and maintained, adequate and correct books and records of account for the Corporation.

(b) Receive or be responsible for receipt of all monies due and payable to the Corporation from any source whatsoever; have charge and custody of, and be responsible for, all monies and other valuables of the Corporation and be responsible for deposit of all such monies in the name and to the credit of the Corporation with such depositaries as may be designated by the Board of Directors or a duly appointed and authorized committee of the Board of Directors.

(c) Disburse or be responsible for the disbursement of the funds of the Corporation as may be ordered by the Board of Directors or a duly appointed and authorized committee of the Board of Directors.

(d) Render to the Chief Executive Officer and the Board of Directors a statement of the financial condition of the Corporation if called upon to do so.

(e) Exercise such powers and perform such duties as are usually vested in the office of chief financial officer of a corporation and exercise such other powers and perform such other duties as may be prescribed by the Board of Directors or these Bylaws.

If any assistant financial officer is appointed, the assistant financial officer, or one of the assistant financial officers, if there are more than one, in the order of their rank as fixed by the Board of Directors or, if they are not so ranked, the assistant financial officer designated by the Board of Directors, shall, in the absence or disability of the Chief Financial Officer or in the event of such officer’s refusal to act, perform the duties and exercise the powers of the Chief

Financial Officer, and shall have such powers and discharge such duties as may be assigned from time to time pursuant to these Bylaws or by the Board of Directors.

Section 4.11 Vice President. In the absence or disability of the Chief Executive Officer or if the office of Chief Executive Officer be vacant, the Vice Presidents in the order determined by the Board of Directors, or if no such determination has been made, in the order of their seniority, shall perform the duties and exercise the powers of the Chief Executive Officer, subject to the right of the Board of Directors at any time to extend or confine such powers and duties or to assign them to others. Any Vice President may have such additional designation in such Vice President's title as the Board of Directors may determine. The Vice Presidents shall generally assist the Chief Executive Officer in such manner as the Chief Executive Officer shall direct. Each Vice President shall have such other powers and perform such other duties as may be assigned from time to time by the Board of Directors or the Chief Executive Officer.

Section 4.12 Secretary. The Secretary shall act as Secretary of all meetings of stockholders and of the Board of Directors at which the Secretary is present, shall record all the proceedings of all such meetings in a book to be kept for that purpose, shall have supervision over the giving and service of notices of the Corporation, and shall have supervision over the care and custody of the records and seal of the Corporation. The Secretary shall be empowered to affix the corporate seal to documents, the execution of which on behalf of the Corporation under its seal is duly authorized, and when so affixed may attest the same. The Secretary shall have all powers and duties usually incident to the office of Secretary, except as specifically limited by a resolution of the Board of Directors. The Secretary shall have such other powers and perform such other duties as may be assigned from time to time by the Board of Directors or the Chief Executive Officer.

Section 4.13 Treasurer. The Treasurer shall have general supervision over the care and custody of the funds and over the receipts and disbursements of the Corporation and shall cause the funds of the Corporation to be deposited in the name of the Corporation in such banks or other depositaries as the Board of Directors may designate. The Treasurer shall have supervision over the care and safekeeping of the securities of the Corporation. The Treasurer shall have all powers and duties usually incident to the office of Treasurer, except as specifically limited by a resolution of the Board of Directors. The Treasurer shall have such other powers and perform such other duties as may be assigned from time to time by the Board of Directors or the Chief Executive Officer.

Section 4.14 Controller. The Controller shall have supervision over the maintenance and custody of the accounting operations of the Corporation, including the keeping of accurate accounts of all receipts and disbursements and all other financial transactions and may, in the discretion of the Board of Directors, be the chief accounting officer of the Corporation. The Controller shall have all powers and duties usually incident to the office of Controller, except as specifically limited by a resolution of the Board of Directors. The Controller shall have such other powers and perform such other duties as may be assigned from time to time by the Board of Directors or the Chief Financial Officer.

Section 4.15 Bond. The Board of Directors shall have power, to the extent permitted by law, to require any officer, agent or employee of the Corporation to give bond for the faithful discharge of such officer, agent or employee's duties in such form and with such surety or sureties as the Board of Directors may determine.

ARTICLE V

CAPITAL STOCK

Section 5.1 Issuance of Certificates of Stock. The shares of capital stock of the Corporation shall be represented by certificates unless the Board of Directors shall by resolution or resolutions provide that some or all of any or all classes or series of stock of the Corporation shall be uncertificated shares of stock. Every holder of stock represented by a certificate shall be entitled to a certificate or certificates in such form as shall be approved by the Board of Directors, certifying the number of shares of capital stock of the Corporation owned by such stockholder. The Board of Directors may appoint a bank or trust company organized under the laws of the United States or any state thereof to act as its transfer agent or registrar, or both in connection with the transfer of any class or series of securities of the Corporation.

Section 5.2 Signatures on Stock Certificates. Certificates for shares of capital stock of the Corporation shall be signed and countersigned by, or in the name of the Corporation by, the Chairman of the Board, the Chief Executive Officer, the President or a Vice President and by, or in the name of the Corporation by, the Secretary, the Treasurer, an Assistant Secretary or an Assistant Treasurer. Any of or all the signatures on the certificates may be a facsimile. In case any officer, transfer agent or registrar who has signed or whose facsimile signature has been placed upon a certificate shall have ceased to be such officer, transfer agent or registrar before such certificate is issued, such certificate may be issued by the Corporation with the same effect as if such signer were such officer at the date of issue.

Section 5.3 Stock Ledger. A record of all certificates for capital stock issued by the Corporation shall be kept by the Secretary or any other officer or employee of the Corporation designated by the Secretary or by any transfer clerk or transfer agent appointed pursuant to Section 5.4 hereof. Such record shall show the name and address of the person, firm or corporation in which certificates for capital stock are registered, the number of shares represented by each such certificate, the date of each such certificate, and in case of certificates which have been canceled, the dates of cancellation thereof.

The Corporation shall be entitled to treat the holder of record of shares of capital stock as shown on the stock ledger as the owner thereof and as the person entitled to receive dividends thereon, to vote such shares and to receive notice of meetings, and for all other purposes. The Corporation shall not be bound to recognize any equitable or other claim to or interest in any share of capital stock on the part of any other person whether or not the Corporation shall have express or other notice thereof, except that a person who is the beneficial owner of shares (if held in a voting trust or by a nominee on behalf of such person), upon providing documentary evidence of beneficial ownership of such shares and satisfying such other conditions as are provided under applicable law, may inspect the books and records of the Corporation.

Section 5.4 Regulations Relating to Transfer. The Board of Directors may make such rules and regulations as it may deem expedient, not inconsistent with law, the Certificate of Incorporation or these Bylaws, concerning issuance, transfer and registration of certificates for shares of capital stock of the Corporation. The Board of Directors may appoint, or authorize any principal officer to appoint, one or more transfer clerks or one or more transfer agents and one or more registrars and may require all certificates for capital stock to bear the signature or signatures of any of them.

Section 5.5 Transfers. Transfers of capital stock shall be made on the books of the Corporation only upon delivery to the Corporation or its transfer agent of (i) a written direction of the registered holder named in the certificate or such holder's attorney lawfully constituted in writing, (ii) the certificate for the shares of capital stock being transferred, and (iii) a written assignment of the shares of capital stock evidenced thereby.

Section 5.6 Cancellation. Each certificate for capital stock surrendered to the Corporation for exchange or transfer shall be canceled and no new certificate or certificates shall be issued in exchange for any existing certificate (other than pursuant to Section 5.7) until such existing certificate shall have been canceled.

Section 5.7 Lost, Destroyed, Stolen and Mutilated Certificates. In the event that any certificate for shares of capital stock of the Corporation shall be mutilated, the Corporation shall issue a new certificate in place of such mutilated certificate. In case any such certificate shall be lost, stolen or destroyed, the Corporation may, in the discretion of the Board of Directors or a committee designated thereby with power so to act, issue a new certificate for capital stock in the place of any such lost, stolen or destroyed certificate. The applicant for any substituted certificate or certificates shall surrender any mutilated certificate or, in the case of any lost, stolen or destroyed certificate, furnish satisfactory proof of such loss, theft or destruction of such certificate and of the ownership thereof. The Board of Directors or such committee may, in its discretion, require the owner of a lost or destroyed certificate, or such owner's representatives, to furnish to the Corporation a bond with an acceptable surety or sureties and in such sum as will be sufficient to indemnify the Corporation against any claim that may be made against it on account of the lost, stolen or destroyed certificate or the issuance of such new certificate. A new certificate may be issued without requiring a bond when, in the judgment of the Board of Directors, it is proper to do so.

Section 5.8 Fixing of Record Dates.

(a) The Board of Directors may fix, in advance, a record date, which shall not be more than sixty nor less than ten days before the date of any meeting of stockholders, nor more than sixty days prior to any other action, for the purpose of determining stockholders entitled to notice of or to vote at such meeting of stockholders or any adjournment thereof, or to receive payment of any dividend or other distribution or allotment of any rights, or to exercise any rights in respect of any change, conversion or exchange of stock or for the purpose of any other lawful action. Except as provided in Section 5.8(b), if no record date is fixed by the Board of Directors, (i) the record date for determining stockholders entitled to notice of or to vote at a meeting of stockholders shall be at the close of business on the day next preceding the day on which notice is given, or, if notice is waived, at the close of business on the day next preceding the day on which the meeting is held and (ii) the record date for determining stockholders for any other purpose shall be at the close of business on the day on which the Board of Directors adopts the resolution relating thereto.

(b) A determination of stockholders of record entitled to notice of or to vote at a meeting of stockholders shall apply to any adjournment of the meeting unless the Board of Directors fixes a new record date for the adjourned meeting.

ARTICLE VI

INDEMNIFICATION

The Corporation shall indemnify any Director or “executive officer” (as such term is defined in Rule 405 promulgated under the Securities Act of 1933, as amended) of the Corporation, and may indemnify any employee or agent of the Corporation who is not a Director or executive officer, who was or is a party or is threatened to be made a party to, or testifies in, any threatened, pending or completed action, suit or proceeding, whether civil, criminal, administrative or investigative in nature, by reason of the fact that such person is or was a Director, officer, employee or agent of the Corporation, or is or was serving at the request of the Corporation as a Director, officer, employee or agent of another corporation, limited liability company, partnership, joint venture, employee benefit plan, trust or other enterprise, against expenses (including attorneys’ fees), judgments, fines and amounts paid in settlement actually and reasonably incurred by such person in connection with such action, suit or proceeding if the person acted in good faith and in a manner the person reasonably believed to be in or not opposed to the best interests of the Corporation, and, with respect to any criminal action or proceeding, had no reasonable cause to believe the person’s conduct was unlawful, to the fullest extent permitted by law as the same exists or may hereafter be amended; provided, however, that, except with respect to proceedings to enforce rights to indemnification, the Corporation shall indemnify any such indemnitee in connection with a proceeding (or part thereof) initiated by such indemnitee only if such proceeding (or part thereof) was authorized by the Board of Directors of the Corporation. The Corporation may enter into agreements with any such person for the purpose of providing for such indemnification.

To the extent that an employee or agent of the Corporation who is not a Director or executive officer has been successful on the merits or otherwise in defense of any action, suit or proceeding referred to in the first paragraph of this Article VI, or in defense of any claim, issue or matter therein, such person may be indemnified against expenses (including attorneys’ fees) actually and reasonably incurred by such person in connection therewith.

Expenses incurred by a Director, executive officer, employee or agent in defending or testifying in a civil, criminal, administrative or investigative action, suit or proceeding shall (in the case of a Director or executive officer of the Corporation) and may (in the case of an employee or agent of the Corporation who is not a Director or executive officer of the Corporation) be paid by the Corporation in advance of the final disposition of such action, suit or proceeding upon receipt of an undertaking by or on behalf of such Director, executive officer, employee or agent to repay such amount if it shall ultimately be determined that such person is not entitled to be indemnified by the Corporation against such expenses as authorized by this Article VI, and the Corporation may enter into agreements with such persons for the purpose of providing for such advances.

The indemnification permitted by this Article VI shall not be deemed exclusive of any other rights to which any person may be entitled under any agreement, vote of stockholders or disinterested Directors or otherwise, both as to action in such person's official capacity and as to action in another capacity while holding an office, and shall continue as to a person who has ceased to be a Director, executive officer, employee or agent of the Corporation and shall inure to the benefit of the heirs, executors and administrators of such person.

The Corporation shall have power to purchase and maintain insurance on behalf of any person who is or was a Director, executive officer, employee or agent of the Corporation, or is or was serving at the request of the Corporation as a Director, officer, employee or agent of another corporation, partnership, joint venture, employee benefit plan trust or other enterprise against any liability asserted against such person and incurred by such person in any such capacity, or arising out of such person's status as such, whether or not the Corporation would have the power to indemnify such person against such liability under the provisions of this Article VI or otherwise.

ARTICLE VII

MISCELLANEOUS PROVISIONS

Section 7.1 Corporate Seal. The seal of the Corporation shall be circular in form with the name of the Corporation in the circumference and the words "Corporate Seal, Delaware" in the center. Alternatively, the Secretary and any Assistant Secretary are authorized to use a seal which has the name "Calpine Subsidiary" in place of the Corporation's name and such alternative seal shall have the same force and effect as the seal otherwise authorized by these Bylaws. The seal may be used by causing it to be affixed or impressed, or a facsimile thereof may be reproduced or otherwise used in such manner as the Board of Directors may determine.

Section 7.2 Fiscal Year. The fiscal year of the Corporation shall be from January 1 to December 31, inclusive, in each year, or such other annual period as the Board of Directors may designate.

Section 7.3 Dividends. The Board of Directors may from time to time declare, and the Corporation may pay, dividends on its outstanding shares in the manner and upon the terms and conditions provided by law and its Certificate of Incorporation.

Section 7.4 Execution of Contracts and Other Instruments. Except as these Bylaws may otherwise provide, the Board of Directors or its duly appointed and authorized committee may authorize any officer or officers, agent or agents, to enter into any contract or execute and deliver any instrument in the name of and on behalf of the Corporation, and such authorization may be general or confined to specific instances. Except as so authorized or otherwise expressly provided in these Bylaws, no officer, agent, or employee shall have any power or authority to bind the Corporation by any contract or engagement or to pledge its credit or to render it liable for any purpose or in any amount.

Section 7.5 Loans. No loans shall be contracted on behalf of the Corporation and no negotiable paper shall be issued in its name, unless and except as authorized by the Board of Directors or its duly appointed and authorized committee. Such authorization may be in the form a signed policy or other blanket authority specified by the Board of Directors from time to time. When so authorized by the Board of Directors or such committee, any officer or agent of the Corporation may effect loans and advances at any time for the Corporation from any bank, trust company, or other institution, or from any firms, corporation or individual, and for such loans and advances may make, execute and deliver promissory notes, bonds or other evidences of indebtedness of the Corporation and, when authorized as aforesaid, may mortgage, pledge, hypothecate or transfer any and all stocks, securities and other property, real or personal, at any time held by the Corporation, and to that end endorse, assign and deliver the same as security for the payment of any and all loans, advances, indebtedness and liabilities of the Corporation. Such authorization may be general or confined to specific instances.

Section 7.6 Bank Accounts. The Board of Directors or its duly appointed and authorized committee from time to time may authorize the opening and keeping of general and/or special bank accounts with such banks, trust companies or other depositaries as may be selected by the Board of Directors or its duly appointed and authorized committee or by any officer or officers or agent or agents of the Corporation to whom such power may be delegated from time to time by the Board of Directors. The Board of Directors or its duly appointed and authorized committee may make such rules and regulations with respect to said bank accounts, not inconsistent with the provisions of these Bylaws, as are deemed advisable.

Section 7.7 Checks, Drafts, Etc. All checks, drafts or other orders for the payment of money, notes, acceptances or other evidences of indebtedness issued in the name of the Corporation shall be signed by such officer or officers or agent or agents of the Corporation, and in such manner, as shall be determined from time to time by resolution of the Board of Directors or its duly appointed and authorized committee. Endorsements for deposit to the credit of the Corporation in any of its duly authorized depositaries may be made, without counter signature, by the Chief Executive Officer or any vice president or the Chief Financial Officer or any assistant financial officer or by any other officer or agent of the Corporation to whom the Board of Directors or its duly appointed and authorized committee, by resolution, shall have delegated such power or by hand stamped impression in the name of the Corporation.

Section 7.8 Waiver of Notice. Whenever any notice is required to be given under any provision of law, the Certificate of Incorporation, or these Bylaws, a written waiver thereof, signed by the person or persons entitled to such notice, whether before or after the time stated therein, shall be deemed equivalent to notice. Neither the business to be transacted at, nor the purpose of, any regular or special meeting of the stockholders, Directors, or members of a committee of Directors, need be specified in any written waiver of notice unless so required by the Certificate of Incorporation.

Section 7.9 Amendment. These Bylaws may be amended as provided in the Certificate of Incorporation.

EXHIBIT 31.1

CERTIFICATIONS

I, Jack A. Fusco, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Calpine Corporation (the "registrant");

2. Based on my knowledge, this 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 report;

3. Based on my knowledge, the financial statements, and other financial information included in this 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 report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, 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 report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 30, 2009

/s/ JACK A. FUSCO

Jack A. Fusco
President, Chief Executive Officer
and Director
Calpine Corporation

EXHIBIT 31.2

CERTIFICATIONS

I, Zamir Rauf, certify that:

1. I have reviewed this quarterly report on Form 10-Q of Calpine Corporation (the "registrant");

2. Based on my knowledge, this 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 report;

3. Based on my knowledge, the financial statements, and other financial information included in this 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 report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, 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 report is being prepared;

b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles;

c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of the registrant's board of directors (or persons performing the equivalent functions):

a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: July 30, 2009

/s/ ZAMIR RAUF

Zamir Rauf
Executive Vice President and
Chief Financial Officer
Calpine Corporation

EXHIBIT 32.1

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 June 30, 2009, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), each of the undersigned does hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of his 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.

/s/ JACK A. FUSCO	/s/ ZAMIR RAUF
Jack A. Fusco	Zamir Rauf
President, Chief Executive Officer	Executive Vice President and
and Director	Chief Financial Officer
Calpine Corporation	Calpine Corporation

Dated: July 30, 2009

A signed original of this written statement required by Section 906 has been provided to Calpine Corporation and will be retained by Calpine Corporation and furnished to the Securities and Exchange Commission or its staff upon request.