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, 2008

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

50 West San Fernando Street, San Jose, California 95113
717 Texas Avenue, Houston, Texas 77002
Telephone: (713) 830-8775

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 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: 422,968,757 shares of Common Stock, par value $.001 per share, outstanding on August 6, 2008.

CALPINE CORPORATION AND SUBSIDIARIES

REPORT ON FORM 10-Q
For the Quarter Ended June 30 2008

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DEFINITIONS

As used in this Report, the abbreviations contained herein have the meanings set forth 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" shall refer 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 thereto in each case as amended, restated, supplemented or otherwise modified to the date of this Report.

ABBREVIATION	DEFINITION
2007 Form 10-K	Calpine Corporation's Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 29, 2008
2014 Convertible Notes	Calpine Corporation's Contingent Convertible Notes Due 2014
401(k) Plan	Calpine Corporation Retirement Savings Plan
Acadia PP	Acadia Power Partners, LLC
AOCI	Accumulated Other Comprehensive Income
ARB	Accounting Research Board
Auburndale	Auburndale Holdings, LLC
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
Blue Spruce	Blue Spruce Energy Center LLC
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(s)	British thermal unit(s)
CAIR	Clean Air Interstate Rule
CalGen	Calpine Generating Company, LLC
CalGen First Lien Debt	Collectively, $235,000,000 First Priority Secured Floating Rate Notes Due 2009, issued by CalGen and CalGen Finance; $600,000,000 First Priority Secured Institutional Terms Loans Due 2009, issued by CalGen; and the CalGen First Priority Revolving Loans, in each case repaid on March 29, 2007
CalGen First Priority Revolving Loans	$200,000,000 First Priority Revolving Loans issued on or about March 23, 2004, pursuant to that Amended and Restated Agreement, among CalGen, the guarantors party thereto, the lenders party thereto, The Bank of Nova Scotia, as administrative agent, L/C Bank, lead arranger and sole bookrunner, Bayerische Landesbank, Cayman Islands Branch, as arranger and co-syndication agent, Credit Lyonnais, New York Branch, as arranger and co-syndication agent, ING Capital LLC, as arranger and co-syndication agent, Toronto Dominion (Texas) Inc., as arranger and co-syndication agent, and Union Bank of California, N.A., as arranger and co-syndication agent, repaid on March 29, 2007
CalGen Second Lien Debt	Collectively, $640,000,000 Second Priority Secured Floating Rate Notes Due 2010, issued by CalGen and CalGen Finance; and $100,000,000 Second Priority Secured Institutional Term Loans Due 2010 issued by CalGen, in each case repaid on March 29, 2007

ABBREVIATION	DEFINITION
CalGen Secured Debt	Collectively, the CalGen First Lien Debt, the CalGen Second Lien Debt and the CalGen Third Lien Debt
CalGen Third Lien Debt	Collectively, $680,000,000 Third Priority Secured Floating Rate Notes Due 2011, issued by CalGen and CalGen Finance; and $150,000,000 11 1/2% Third Priority Secured Notes Due 2011, issued by CalGen and CalGen Finance, in each case repaid on March 29, 2007
Calpine Debtors	The U.S. Debtors and the Canadian Debtors
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
Cash Collateral Order	Second Amended Final Order of the U.S. Bankruptcy Court Authorizing Use of Cash Collateral and Granting Adequate Protection, dated February 24, 2006 as modified by orders of the U.S. Bankruptcy Court dated June 21, 2006, July 12, 2006, October 25, 2006, November 15, 2006, December 20, 2006, December 28, 2006, January 17, 2007, and March 1, 2007
CCAA	Companies' Creditors Arrangement Act (Canada)
CCFC	Calpine Construction Finance Company, L.P.
CES	Calpine Energy Services, L.P.
Chapter 11	Chapter 11 of the Bankruptcy Code
Cleco	Cleco Corp.
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 Margin	Non-GAAP financial measure that includes electricity and steam revenues, hedging and optimization activities, renewable energy credit revenue, transmission revenue and expenses, and fuel and purchased energy expense, but excludes mark-to-market activity and other service 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
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

ABBREVIATION	DEFINITION
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
EAB	Environmental Appeals Board of the U.S. Environmental Protection Agency
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
EITF	Emerging Issues Task Force
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
ERISA	Employee Retirement Income Security Act
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
FIN	FASB Interpretation Number
Fremont	Fremont Energy Center, LLC
FSP	FASB Staff Position
GAAP	Generally accepted accounting principles
Greenfield LP	Greenfield Energy Centre LP
Harbert Convertible Fund	Harbert Convertible Arbitrage Master Fund, L.P.
Heat Rate	A measure of the amount of fuel required to produce a unit of electricity
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)
LIBOR	London Inter-Bank Offered Rate
LSTC	Liabilities subject to compromise

ABBREVIATION	DEFINITION
Market Capitalization	Market value of Calpine Corporation common stock outstanding, calculated in accordance with the Calpine Corporation amended and restated certificate of incorporation
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
MW	Megawatt(s)
MWh	Megawatt hour(s)
Ninth Circuit Court of Appeals	U.S. Court of Appeals for the Ninth Circuit
NOL(s)	Net operating loss(es)
Non-U.S. Debtor(s)	The consolidated subsidiaries and affiliates of Calpine Corporation that are not U.S. Debtors
Northern District Court	U.S. District Court for the Northern District of California
NRG	NRG Energy, Inc.
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
OCI	Other Comprehensive Income
OMEC	Otay Mesa Energy Center, LLC
Original DIP Facility	The Revolving Credit, Term Loan and Guarantee Agreement, dated as of December 22, 2005, as amended on January 26, 2006, and as amended and restated by that certain Amended and Restated Revolving Credit, Term Loan and Guarantee Agreement, dated as of February 23, 2006, among Calpine Corporation, as borrower, the Guarantors party thereto, the Lenders from time to time party thereto, Credit Suisse Securities (USA) LLC and Deutsche Bank Securities Inc., as joint syndication agents, Deutsche Bank Trust Company Americas, as administrative agent for the First Priority Lenders, General Electric Capital Corporation, as Sub-Agent for the Revolving Lenders, Credit Suisse, as administrative agent for the Second Priority Term Lenders, Landesbank Hessen Thuringen Girozentrale, New York Branch, General Electric Capital Corporation and HSH Nordbank AG, New York Branch, as joint documentation agents for the First Priority Lenders and Bayerische Landesbank, General Electric Capital Corporation and Union Bank of California, N.A., as joint documentation agents for the Second Priority Lenders
OTC	Over the Counter
Panda	Panda Energy International, Inc., and related party PLC II, LLC
PCAOB	Public Company Accounting Oversight Board
PCF	Power Contract Financing, L.L.C.
PCF III	Power Contract Financing III, LLC
Petition Date	December 20, 2005

ABBREVIATION	DEFINITION
Plan of Reorganization	Debtors' Sixth Amended Joint Plan of Reorganization Pursuant to Chapter 11 of the U.S. 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
Pomifer	Pomifer Power Funding, LLC, a subsidiary of Arclight Energy Partners Fund I, L.P.
PPA(s)	Any 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
PSD	Prevention of Significant Deterioration Permit
PSM	Power Systems Manufacturing, LLC
RockGen	RockGen Energy LLC
RockGen Owner Lessors	Collectively, RockGen OL-1, LLC; RockGen OL-2, LLC; RockGen OL-3, LLC and RockGen OL-4, LLC
Rosetta	Rosetta Resources Inc.
SAB	Staff Accounting Bulletin
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 Court of Appeals	U.S. Court of Appeals for the Second Circuit
Second Priority Debt	Collectively, the Second Priority Notes and 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
SOP 90-7	Statement of Position 90-7, "Financial Reporting by Entities in Reorganization Under the Bankruptcy Code"
Spark spread	The spread between the sales price for electricity generated and the cost of fuel
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

ABBREVIATION	DEFINITION
U.S. Debtor(s)	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
Whitby	Whitby Cogeneration Limited Partnership

PART I — FINANCIAL INFORMATION

Item 1. ***Financial Statements***

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED CONDENSED BALANCE SHEETS
(Unaudited)

	June 30, 2008	December 31, 2007
	(in millions, except share and per share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 370	$ 1,915
Accounts receivable, net of allowance of $31 and $54	1,443	878
Accounts receivable, related party	1	226
Materials and supplies	152	114
Margin deposits and other prepaid expense	836	452
Restricted cash, current	357	422
Current derivative assets	5,053	731
Current assets held for sale	—	195
Other current assets	113	98
Total current assets	8,325	5,031
Property, plant and equipment, net	12,131	12,292
Restricted cash, net of current portion	168	159
Investments	386	260
Long-term derivative assets	694	290
Other assets	917	1,018
Total assets	$ 22,621	$ 19,050
LIABILITIES & STOCKHOLDERS' EQUITY (DEFICIT)		
Current liabilities:		
Accounts payable	$ 1,190	$ 642
Accrued interest payable	101	324
Debt, current portion	308	1,710
Current derivative liabilities	5,486	806
Income taxes payable	49	51
Other current liabilities	318	571
Total current liabilities	7,452	4,104
Debt, net of current portion	10,104	9,946
Deferred income taxes, net of current portion	127	38
Long-term derivative liabilities	1,029	578
Other long-term liabilities	235	245
Total liabilities not subject to compromise	18,947	14,911
Liabilities subject to compromise	—	8,788
Commitments and contingencies (see Note 12)		
Minority interest	3	3
Stockholders' equity (deficit):		
Preferred stock, $.001 par value per share; authorized 100,000,000 shares, none issued and outstanding in 2008; authorized 10,000,000 shares, none issued and outstanding in 2007	—	—
Common stock, $.001 par value per share; authorized 1,400,000,000 shares, 423,127,138 shares issued and 423,126,665 shares outstanding in 2008; authorized 2,000,000,000 shares, 568,314,685 issued and 479,314,685 outstanding in 2007	1	1
Additional paid-in capital	12,185	3,263
Accumulated deficit	(7,724)	(7,685)
Accumulated other comprehensive loss	(791)	(231)
Total stockholders' equity (deficit)	3,671	(4,652)
Total liabilities and stockholders' equity (deficit)	$ 22,621	$ 19,050

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

See Note 12 of the Notes to Consolidated Condensed Financial Statements for a further discussion related to the potential sale of Auburndale.

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED CONDENSED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	**2007**	**2008**	**2007**
	(in millions, except share and per share amounts)			
Operating revenues	$ 2,828	$ 2,060	$ 4,779	$ 3,722
Cost of revenue:				
Fuel and purchased energy expense	2,008	1,456	3,613	2,727
Plant operating expense	206	211	438	379
Depreciation and amortization expense	108	118	219	236
Other cost of revenue	30	33	62	70
Total cost of revenue	2,352	1,818	4,332	3,412
Gross profit	476	242	447	310
Sales, general and other administrative expense	48	39	96	79
Other operating (income) expense	(5)	3	—	12
Income from operations	433	200	351	219
Interest expense	206	264	625	564
Interest (income)	(14)	(17)	(27)	(34)
Minority interest income	—	(3)	—	(1)
Other (income) expense, net	1	(6)	11	(7)
Income (loss) before reorganization items and income taxes	240	(38)	(258)	(303)
Reorganization items	18	469	(261)	574
Income (loss) before income taxes	222	(507)	3	(877)
Provision (benefit) for income taxes	25	(7)	20	82
Net income (loss)	$ 197	$ (500)	$ (17)	$ (959)
Basic earnings (loss) per common share:				
Weighted average shares of common stock outstanding (in thousands)	485,004	479,175	485,002	479,155
Net income (loss)	$ 0.41	$ (1.04)	$ (0.04)	$ (2.00)
Diluted earnings (loss) per common share:				
Weighted average shares of common stock outstanding (in thousands)	485,732	479,175	485,002	479,155
Net income (loss)	$ 0.41	$ (1.04)	$ (0.04)	$ (2.00)

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

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED CONDENSED STATEMENTS OF COMPREHENSIVE INCOME (LOSS) AND STOCKHOLDERS' EQUITY (DEFICIT)
For the Six Months Ended June 30, 2008
(Unaudited)

	Common Stock	Additional Paid-In Capital	Accumulated Deficit	Accumulated Other Comprehensive Income(Loss) Net Unrealized Gain (Loss) From: Cash Flow Hedges	Foreign Currency Translation	Total Stockholders' Equity (Deficit)
	(in millions)					
Balance, December 31, 2007	$ 1	$ 3,263	$ (7,685)	$ (241)	$ 10	$ (4,652)
Cancellation of Calpine Corporation common stock	(1)	(3,263)	—	—	—	(3,264)
Issuance of reorganized Calpine Corporation common stock in accordance with the Plan of Reorganization	1	12,166	—	—	—	12,167
Stock compensation expense	—	19	—	—	—	19
Cumulative effect of adjustment from adoption of SFAS No. 157	—	—	(22)	—	—	(22)
Total stockholders' equity before comprehensive income (loss) items						4,248
Net loss	—	—	(17)	—	—	(17)
Loss on cash flow hedges before reclassification adjustment	—	—	—	(572)	—	(572)
Reclassification adjustment	—	—	—	22	—	22
Foreign currency translation loss	—	—	—	—	(6)	(6)
Provision for income taxes	—	—	—	(4)	—	(4)
Total comprehensive loss						(577)
Balance, June 30, 2008	$ 1	$ 12,185	$ (7,724)	$ (795)	$ 4	$ 3,671

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, 2008	Six Months Ended June 30, 2007
	(in millions)	
Cash flows from operating activities:		
Net loss	$ (17)	$ (959)
Adjustments to reconcile net loss to net cash used in operating activities:		
Depreciation and amortization[1]	280	284
Deferred income taxes, net	85	82
Loss on sale of assets, excluding reorganization items	6	10
Foreign currency transaction gain	(7)	(6)
Change in derivatives	(158)	(10)
Derivative contracts classified as financing activities	(34)	—
Income from unconsolidated investments in power projects	(13)	—
Stock compensation expense	19	(1)
Reorganization items	(322)	497
Other	7	(3)
Change in operating assets and liabilities, net of effects of acquisitions:		
Accounts receivable	(246)	(232)
Other assets	(239)	(147)
Accounts payable, LSTC and accrued expenses	382	319
Other liabilities	(329)	(18)
Net cash used in operating activities	(586)	(184)
Cash flows from investing activities:		
Purchases of property, plant and equipment	(79)	(128)
Disposals of property, plant and equipment	11	15
Proceeds from sale of investments, turbines and power plants	398	398
Cash acquired due to reconsolidation of Canadian entities	64	—
Contributions to unconsolidated investments	(9)	(68)
Return of investment from unconsolidated investments	24	92
Decrease in restricted cash	56	60
Cash effect of deconsolidation of OMEC	—	(29)
Other	4	3
Net cash provided by investing activities	469	343

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, 2008	Six Months Ended June 30, 2007
Cash flows from financing activities:		
Repayments of notes payable and lines of credit	$ (49)	$ (89)
Borrowings from project financing	356	15
Repayments of project financing	(253)	(69)
Repayments on CalGen financing	—	(224)
DIP Facility borrowings	—	614
Repayments of DIP Facility	(113)	(18)
Borrowings under Exit Facility	3,473	—
Repayments on Exit Facility	(855)	—
Repayments on Second Priority Debt	(3,672)	—
Redemptions of preferred interests	(161)	(4)
Financing costs	(187)	(60)
Derivative contracts	34	—
Other	(1)	3
Net cash provided by (used in) financing activities	(1,428)	168
Net increase (decrease) in cash and cash equivalents	(1,545)	327
Cash and cash equivalents, beginning of period	1,915	1,077
Cash and cash equivalents, end of period	$ 370	$ 1,404
Cash paid (received) during the period for:		
Interest, net of amounts capitalized	$ 163	$ 585
Income taxes	$ 15	$ 1
Reorganization items included in operating activities, net	$ 109	$ 65
Reorganization items included in investing activities, net	$ (414)	$ (250)
Reorganization items included in financing activities, net	$ —	$ 52
Supplemental disclosure of non-cash investing and financing activities:		
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 common stock	$ 3,703	$ —
DIP Facility borrowings used to extinguish the Original DIP Facility principal $(989), CalGen Secured Debt principal $(2,309), and operating liabilities $(88)	$ —	$ 3,386
Project financing $(159) and operating liabilities $(33) extinguished with sale of Aries Power Plant	$ —	$ 192
Fair value of loaned common stock returned	$ —	$ 123
Letter of credit draws under the CalGen Secured Debt used for operating activities	$ —	$ 16
Fair value of Metcalf cooperation agreement, with offsets to notes payable $(6) and operating liabilities $(6)	$ —	$ 12

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(1) Includes depreciation and amortization that is also recorded in sales, general and other administrative expense and interest expense.

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, 2008
(Unaudited)

1. Basis of Presentation and Summary of Significant Accounting Policies

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, 2007, included in our 2007 Form 10-K. The results for interim periods are not necessarily indicative of the results for the entire year.

During the three and six month periods ended June 30, 2007, and for the period January 1, 2008, through January 31, 2008, the Effective Date, 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 the Effective Date. Our Consolidated Condensed Financial Statements have been prepared in accordance with SOP 90-7 which requires that financial statements, for periods subsequent to our Chapter 11 filings, distinguish transactions and events that are directly associated with the reorganization from the ongoing operations of the business. Accordingly, 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. We determined that we did not meet the requirements to adopt fresh start accounting on the Effective Date of our emergence from Chapter 11 because the reorganization value of our assets exceeded the total of post-petition liabilities and allowed claims. See Note 2 for further discussion of our Plan of Reorganization and the applicability of fresh start accounting.

We operate in one line of business, the generation and sale of electricity and electricity-related products. We assess our business primarily on a regional basis due to the impact on our financial performance of the differing characteristics of these regions. Our reportable segments are West (including geothermal), Texas, Southeast, North and Other. Our Other segment includes fuel management, our turbine maintenance group, our PSM business for periods prior to its sale and certain hedging and other corporate activities. See Note 13 for segment information.

Canadian Subsidiaries — As a result of filings by the Canadian Debtors under the CCAA in the Canadian Court, we deconsolidated most of our Canadian 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. Because of the uncertainty, as of the Petition Date, of our emergence from our CCAA and Chapter 11 cases, we fully impaired our investment in our Canadian and other foreign subsidiaries and accounted for such investments under the cost method. The impairment charge was included in reorganization items on our 2005 Consolidated Statement of Operations.

On February 8, 2008, the Canadian Effective Date, the Canadian Court ordered and declared that the proceedings under the CCAA 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 net assets include debt, 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 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 $107 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 $37 million) to $0 and recorded the $70 million balance of the excess as a gain in reorganization items on our Consolidated Condensed Statement of Operations in the first quarter of 2008.

Deconsolidations — We deconsolidated OMEC during the second quarter of 2007 as a result of a 10-year tolling agreement we entered into with SDG&E and assignment of rights under an existing ground lease and ground sublease and easement agreement to SDG&E in May 2007 which, among other things, provides for a put option by OMEC to sell, and a call option by SDG&E to buy, the Otay Mesa facility at the end of the tolling agreement. The tolling agreement and the put and call options were determined to absorb the majority of expected losses and residual returns from the entity such that we are not OMEC's primary beneficiary. Since the second quarter of 2007, we have accounted for our investment in OMEC under the equity method. See Note 4 for a further discussion of our investment in OMEC.

On December 6, 2007, our subsidiary RockGen, which had leased the RockGen Energy Center from the RockGen Owner Lessors pursuant to a sale and leaseback arrangement, entered into a settlement agreement and a purchase and sale agreement with the RockGen Owner Lessors to purchase the RockGen Energy Center for an allowed general unsecured claim of approximately $145 million. While the allowed claim was approved by the U.S. Bankruptcy Court in December 2007, the purchase agreement was conditional upon certain events before title could transfer to us. All of the conditions were satisfied in January 2008 and the acquisition of RockGen closed on January 15, 2008.

We determined that RockGen is a variable interest entity, and our purchase of the RockGen assets triggered a reevaluation under FIN 46(R), "Consolidation of Variable Interest Entities – an Interpretation of ARB No. 51," to determine RockGen's primary beneficiary. Our PPA between RockGen and Wisconsin Power & Light contains a call option which allows Wisconsin Power & Light and related parties to purchase RockGen on May 31, 2009, provided they give 180 days prior written notice. The call option was determined to absorb the majority of expected losses and residual returns from the entity such that we are not RockGen's primary beneficiary. Accordingly, we deconsolidated RockGen during the first quarter of 2008, and our investment in RockGen is accounted for under the equity method. See Note 4 for further discussion of our investment in RockGen.

Reclassifications — Certain reclassifications have been made to prior periods to conform to the current period presentation. In particular, mark-to-market gains and losses on derivative gas contracts are classified as part of fuel and purchased energy expense. Previously, these gains and losses were included in mark-to-market activity, net, which was previously a separate component within operating revenues. Additionally, the cash flows related to derivatives not designated as hedges are classified in operating activities on the Consolidated Condensed Statements of Cash Flows. Previously, these cash flows were classified within investing activities.

Cash and Cash Equivalents — We have certain project finance facilities and lease agreements that establish segregated cash accounts. These accounts have been pledged as security in favor of the lenders to 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, 2008, and December 31, 2007, $213 million and $257 million, respectively, of the cash and cash equivalents balance that was unrestricted was 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 by regulatory agencies. These amounts are held by depository banks in order to comply with the contractual provisions requiring reserves for payments such as for debt service, rent, major maintenance and debt repurchases. Funds that can be used to satisfy obligations due during the next twelve months are classified as current restricted cash, with the remainder classified as non-current restricted cash. Restricted cash is 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 consolidated restricted cash as of June 30, 2008, and December 31, 2007 (in millions):

	June 30, 2008			December 31, 2007		
	Current	Non-Current	Total	Current	Non-Current	Total
Debt service	$ 116	$ 114	$ 230	$ 128	$ 111	$ 239
Rent reserve	20	—	20	11	—	11
Construction/major maintenance	51	29	80	62	26	88
Security/project reserves	107	1	108	189	—	189
Collateralized letters of credit and other credit support	39	1	40	4	—	4
Other	24	23	47	28	22	50
Total	$ 357	$ 168	$ 525	$ 422	$ 159	$ 581

Income Taxes — For income tax reporting purposes our consolidated GAAP financial reporting group is comprised of two groups, CCFC and its subsidiaries and Calpine and its consolidated, non-CCFC subsidiaries. This is due to a preferred financing transaction in 2005 resulting in the deconsolidation of CCFC for income tax purposes. For the three and six months ended June 30, 2008, we have determined that the effective tax rate method for computing the tax provision of Calpine and its consolidated, non-CCFC subsidiaries does not provide meaningful results because of the uncertainty in reliably estimating their 2008 projected annual effective tax rate. As a result, we calculate our tax expense on Calpine and its consolidated, non-CCFC subsidiaries based on an actual, or discrete, method. CCFC and its subsidiaries no longer have a valuation allowance recorded against their deferred tax assets; therefore, we utilize the effective tax rate method in determining their tax expense. The sum of the tax expense (benefit) determined for each group under these methods for the three and six months ended June 30, 2008 and 2007, was $25 million and $(7) million, respectively and $20 million and $82 million, respectively.

Under federal income tax law, NOL carryforwards can be utilized to reduce future taxable income. However, our ability to utilize our NOL carryforwards is subject to certain limitations if we undergo an ownership change as defined by the Internal Revenue Code. We experienced an ownership change on the Effective Date as a result of the distribution of reorganized Calpine Corporation common stock pursuant to the Plan of Reorganization. We do not expect the annual limitation from this ownership change 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 prior to the ownership change, our ability to utilize our NOL carryforwards may be significantly limited.

Our certificate of incorporation permits our Board of Directors to impose certain transfer restrictions on our common stock in certain circumstances. If, prior to February 1, 2013, our Market Capitalization declines by 35% from our Emergence Date Market Capitalization of approximately $8.6 billion (calculated pursuant to our certificate of incorporation) and 25 percentage points of ownership change have occurred (calculated pursuant to Section 382 of the Internal Revenue Code), our Board of Directors is required to meet to determine whether to impose those restrictions. These restrictions are designed to minimize the likelihood of an ownership change occurring and thereby preserve our ability to utilize our NOLs. These restrictions are not currently operative but could become operative in the future if the foregoing events occur. However, there is no assurance that our Board of Directors would choose to impose these restrictions or that such restrictions would prevent an ownership change from occurring.

GAAP requires that we consider all available evidence and tax planning strategies, both positive and negative, 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 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. For the six months ended June 30, 2008, we provided a valuation allowance of $255 million on certain Canadian deferred tax assets recorded with the reconsolidation of our Canadian subsidiaries in February 2008. Additionally, we provided an additional valuation allowance of $292 million due to deferred tax assets related to OCI for the six months ended June 30, 2008.

As of June 30, 2008, we had unrecognized tax benefits of $91 million. If recognized, $33 million of our unrecognized tax benefits could impact the annual effective tax rate and $58 million related to deferred tax assets could be offset against recorded valuation allowances within the next twelve months. We also had accrued interest and penalties of $18 million for income tax matters as of June 30, 2008. The amount of unrecognized tax benefits decreased by $86 million for the six months ended June 30, 2008, primarily related to our settlement of intercompany loans with certain of our Canadian subsidiaries for $52 million and the settlement of an IRS examination for $29 million.

Our U.S. income tax returns for 2004 through 2006 tax years are still subject to IRS examination. Due to significant NOLs incurred in these years, any IRS adjustment of these returns would likely result in a reduction of the deferred tax assets already subject to valuation allowances rather than a cash payment of taxes.

Recent Accounting Pronouncements

SFAS No. 157 — In September 2006, FASB issued SFAS No. 157, “Fair Value Measurements,” which is 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. In February 2008, the FASB issued FSP No. FAS 157-2, “Effective Date of FASB Statement No. 157,” which defers the effective date of SFAS No. 157 for non-financial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until fiscal years and interim periods beginning after November 15, 2008. We have certain potential non-recurring, non-financial assets and non-financial liabilities recorded at fair value that fall within the scope of FSP No. FAS 157-2 that include asset retirement obligations initially measured at fair value and long-lived assets measured at fair value for impairment testing. We expect to adopt FSP No. FAS 157-2 as of January 1, 2009, and we are currently assessing the impact of applying SFAS No. 157 to non-financial assets and non-financial liabilities on our results of operations, cash flows and financial position. We have adopted SFAS No. 157 as of January 1, 2008, related to financial assets and financial liabilities. See Note 8 for a discussion of the impact of adopting this standard.

FASB Staff Position No. FIN 39-1 — In April 2007, the FASB staff issued FSP FIN 39-1, “Amendment of FASB Interpretation No. 39.” FSP FIN 39-1 requires an entity to offset the fair value amounts recognized for cash collateral paid or cash collateral received against the fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement, if the entity elects to offset (net) fair value amounts recognized as derivative instruments. Under the provisions of this pronouncement, a reporting entity shall make an accounting decision whether or not to offset fair value amounts. We adopted FSP FIN 39-1 on January 1, 2008, and elected not to apply the netting provisions allowed under FSP FIN 39-1. We have presented our derivative assets and liabilities on a gross basis as of June 30, 2008, on our Consolidated Condensed Balance Sheets in accordance with this standard. Adoption of this standard had no effect on our results of operations or cash flows.

In accordance with FSP FIN 39-1, we retrospectively adjusted derivative assets and liabilities from a net to a gross basis on our Consolidated Condensed Balance Sheet as of December 31, 2007, to conform to current period presentation. The effect to our Consolidated Condensed Balance Sheet as of December 31, 2007, was as follows (in millions) (only line items impacted are shown):

	December 31, 2007	
	As Previously Reported	**As Adjusted**
Current derivative assets	$ 231	$ 731
Total current assets	4,531	5,031
Long-term derivative assets	222	290
Total assets	$ 18,482	$ 19,050
Current derivative liabilities	$ (306)	$ (806)
Total current liabilities	(3,604)	(4,104)
Long-term derivative liabilities	(510)	(578)
Total liabilities not subject to compromise	(14,343)	(14,911)
Total liabilities and stockholders’ equity (deficit)	$ (18,482)	$ (19,050)

SFAS No. 141(R) — In December 2007, FASB issued SFAS No. 141(R), “Business Combinations,” which replaces SFAS No. 141. SFAS No. 141(R) 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. SFAS No. 141(R) is effective as of the beginning of an entity’s fiscal year that begins after December 15, 2008, with early adoption prohibited. We are currently assessing the impact this standard might have on our results of operations, cash flows and financial position.

SFAS No. 160 — 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 are currently assessing the impact this standard will have on our results of operations, cash flows and financial position.

SFAS No. 161 — 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. Since SFAS No. 161 requires only additional disclosures regarding derivatives and hedging activities and does not impact accounting entries, we do not expect this standard to have a material impact on our results of operations, cash flows or financial position.

SFAS No. 162 — In May 2008, FASB issued SFAS No. 162, “The Hierarchy of Generally Accepted Accounting Principles.” SFAS No. 162 identifies the sources of accounting principles and the framework for selecting the principles used in the preparation of financial statements of nongovernmental entities that are presented in conformity with GAAP. SFAS No. 162 is effective 60 days following the SEC’s approval of the amendments to the PCAOB Interim Auditing Standards, AU Section 411, “The Meaning of Present Fairly in Conformity with Generally Accepted Accounting Principles.” We do not expect this statement to have a material impact on our results of operations, cash flows or financial position.

2. Our Emergence from Chapter 11

Summary of Proceedings and General Bankruptcy Matters — From the Petition Date through the Effective Date, we operated as a debtor-in-possession under the protection of the U.S. Bankruptcy Court following filings by Calpine Corporation and 274 of its wholly owned U.S. subsidiaries of voluntary petitions for relief under Chapter 11 of the Bankruptcy Code. In addition, during that period, 12 of our Canadian subsidiaries that had filed for creditor protection under the CCAA also operated as debtors-in-possession under the jurisdiction of the Canadian Court.

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 Calpine Debtors generally were stayed. Following the Effective Date, actions to enforce or otherwise effect repayment of liabilities preceding the Petition Date, as well as pending litigation against the Calpine 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.

Plan of Reorganization — Our Plan of Reorganization became effective on January 31, 2008. The Plan of Reorganization provides for the treatment of claims against and interests in the U.S. Debtors. Pursuant to the Plan of Reorganization, allowed administrative claims are being paid in full in cash and cash equivalents, as are allowed first and second lien debt claims. Priority tax claims are being paid in full in cash and cash equivalents or with a distribution of the reorganized Calpine Corporation common stock. Other allowed secured claims are being reinstated, paid in full in cash or cash equivalents, or having the collateral securing such claims returned to the secured creditor. Make whole claims arising in connection with the repayment of the CalGen Second Lien Debt and the CalGen Third Lien Debt that are ultimately allowed will be paid in full using cash and cash equivalents or the reorganized Calpine Corporation common stock held in reserve pursuant to the Plan of Reorganization. To the extent that the common stock reserved on account for such make whole claims is insufficient in value to satisfy such claims in full, we must use other available cash to satisfy such claims. Allowed unsecured claims are receiving a pro rata distribution of all common stock of the reorganized Calpine Corporation to be issued under the Plan of Reorganization (except shares reserved for issuance under the Calpine Equity Incentive Plans). Allowed unsecured convenience claims (subject to certain exceptions, all unsecured claims $50,000 or less) are being paid in full in cash or cash equivalents. Holders of allowed interests in Calpine Corporation (primarily holders of Calpine Corporation common stock existing as of the Petition Date) received a pro rata share of warrants to purchase approximately 48.5 million shares of reorganized Calpine Corporation common stock, subject to certain terms. Holders of subordinated equity securities claims did not receive a distribution under the Plan of Reorganization and may only recover from applicable insurance proceeds. Because certain disputed claims were not resolved as of the Effective Date and are not yet finally adjudicated, no assurances can be given that actual claim amounts may not be materially higher or lower than confirmed in the Plan of Reorganization.

In connection with the consummation of the Plan of Reorganization, we closed on our approximately $7.3 billion of Exit Facilities, comprising the approximately $4.9 billion of outstanding loan amounts and commitments under the DIP Facility (including the $1.0 billion revolver), which were converted into exit financing under the Exit Credit Facility, approximately $2.1 billion of additional term loan facilities under the Exit Credit Facility and $300 million of term loans under the Bridge Facility. Amounts drawn under the Exit Facilities at closing were used to fund cash payment obligations under the Plan of Reorganization including the repayment of a portion of the Second Priority Debt and the payment of administrative claims and other pre-petition claims, as well as to pay fees and expenses in connection with the Exit Facilities and for working capital and general corporate purposes. As of March 6, 2008, the Bridge Facility had been repaid in full in accordance with its terms.

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 shares of reorganized Calpine Corporation common stock was authorized. Through the filing of this Report, approximately 421 million shares have been distributed to holders of allowed unsecured claims against the U.S. Debtors, approximately 10 million shares are being held pending resolution of certain intercreditor matters and approximately 54 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. Additionally, certain disputed claims, including litigation instituted by us challenging so-called "make whole," premium, or "no-call" claims have not yet been finally adjudicated and may be required to be settled in cash and cash equivalents or reorganized Calpine Corporation common stock held in reserve pursuant to the Plan of Reorganization. To the extent that the common stock reserved on account for such make whole claims is insufficient in value to satisfy such claims in full, we must use other available cash to satisfy such claims. No assurances can be given that settlements may not be materially higher or lower than we originally estimated.

Pursuant to the Plan of Reorganization, we were also authorized to issue up to 15 million shares under the Calpine Equity Incentive Plans, and we issued warrants to purchase approximately 48.5 million shares of common stock at $23.88 per share to holders of our previously outstanding common stock. Each warrant represents the right to purchase a single share of our new common stock and will expire on August 25, 2008. As of June 30, 2008, we have issued approximately 2 million shares of restricted stock, net of forfeitures, and options to purchase approximately 5 million shares of common stock, net of forfeitures, under the Calpine Equity Incentive Plans.

The reorganized Calpine Corporation common stock is listed on the NYSE. Our common stock began "when issued" trading on the NYSE under the symbol "CPN-WI" on January 16, 2008, and began "regular way" trading on the NYSE under the symbol "CPN" on February 7, 2008. Our authorized equity consists of 1.5 billion shares comprising 1.4 billion shares of common stock, par value $.001 per share, and 100 million shares of preferred stock which preferred stock may be issued in one or more series, with such voting rights and other terms as our Board of Directors determines.

Several parties have filed appeals seeking reconsideration of the Confirmation Order. See Note 12 for further discussion.

In connection with our emergence from Chapter 11, we recorded certain "plan effect" adjustments to our Consolidated Condensed Balance Sheet as of the Effective Date in order to reflect certain provisions of our Plan of Reorganization. These adjustments included the distribution of approximately $4.1 billion in cash and the authorized issuance of 485 million shares of reorganized Calpine Corporation common stock primarily for the discharge of LSTC, repayment of the Second Priority Debt and for various other administrative and other post-petition claims. As a result, our equity increased by approximately $8.9 billion. We borrowed approximately $6.4 billion under our Exit Facilities, which was used to repay the outstanding term loan balance of $3.9 billion (excluding the unused portion under the $1.0 billion revolver) under our DIP Facility. The remaining net proceeds of approximately $2.5 billion were used to fund cash payment obligations under the Plan of Reorganization including the repayment of a portion of the Second Priority Debt and the payment of administrative claims.

Applicability of Fresh Start Accounting — At the Effective Date, we did not meet the requirements under SOP 90-7 to adopt fresh start accounting because the reorganization value of our assets exceeded the total of post-petition liabilities and allowed claims.

Interest Expense — We recorded interest expense in December 2007 for allowed claims under the Plan of Reorganization of $347 million related to post-petition interest on LSTC incurred from the Petition Date through December 31, 2007, and we recorded $148 million in additional post-petition interest from January 1, 2008, through the

Effective Date. Prior to recording the post-petition interest on pre-petition LSTC, interest expense related to pre-petition LSTC was reported only to the extent that it was paid during the pendency of the Chapter 11 cases or was permitted by the Cash Collateral Order or other orders of the U.S. Bankruptcy Court. Contractual interest (at non-default rates) owed to unrelated parties on pre-petition LSTC not reflected on our Consolidated Condensed Financial Statements was $60 million for the three months ended June 30, 2007, and $120 million for the six months ended June 30, 2007. Additionally, we made periodic cash adequate protection payments to the holders of Second Priority Debt on a quarterly basis during the year ended December 31, 2007, which were classified as interest expense on our Consolidated Condensed Statements of Operations during the three and six months ended June 30, 2007.

Reorganization Items — Reorganization items represent the direct and incremental costs related to our Chapter 11 cases, such as professional 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 gains on the sale of assets or resulting from certain settlement agreements related to our restructuring activities.

The table below lists the significant components of reorganization items for the three and six months ended June 30, 2008 and 2007 (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	**2007**	**2008**	**2007**
Provision for expected allowed claims	$ 5	$ 230	$ (54)	$ 335
Professional fees	14	49	76	95
Gains on asset sales, net of equipment impairments	—	—	(203)	(250)
Asset impairments	—	106	—	120
Loss (gain) on reconsolidation of Canadian Debtors	5	—	(65)	—
DIP Facility financing and CalGen Secured Debt repayment costs	—	—	(4)	160
Interest (income) on accumulated cash	—	(15)	(7)	(23)
Other	(6)	99	(4)	137
Total reorganization items	$ 18	$ 469	$ (261)	$ 574

Provision for expected allowed claims — Represents the change in our estimate of the 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. During the three and six months ended June 30, 2007, our provision for expected allowed claims consisted primarily of our estimate of claims related to the rejection or repudiation of leases, natural gas transportation contracts, and PPAs.

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 5 for further discussion of our sales of Hillabee and Fremont. The sales of these assets and utilization of the sales proceeds to repay the Bridge Facility were part of our Plan of Reorganization and are included in reorganization items even though the sales closed subsequent to the Effective Date. The amounts recorded for the six months ended June 30, 2007, primarily represent the gains recorded on the sales of the assets of MEP Pleasant Hill, LLC (consisting primarily of the Aries Power Plant), Goldendale Energy Center and PSM.

Asset impairments — Impairment charges for the six months ended June 30, 2007, primarily relate to recording our interest in Acadia PP at fair value less costs to sell.

Other — Other reorganization items consist primarily of adjustments for foreign exchange rate changes on LSTC denominated in a foreign currency and governed by foreign law, employee severance and emergence incentive costs during the three and six months ended June 30, 2008 and 2007.

U.S. Debtors Condensed Combined Financial Statements for the Three and Six Months Ended June 30, 2007

Basis of Presentation — The U.S. Debtors' Condensed Combined Financial Statements exclude the financial statements of the Non-U.S. Debtor parties. Transactions and balances of receivables and payables between U.S. Debtors are eliminated in consolidation.

Condensed Combined Financial Statements of the U.S. Debtors are set forth below (in millions):

Condensed Combined Statements of Operations

	Three Months Ended June 30, 2007	Six Months Ended June 30, 2007
Total revenue	$ 1,828	$ 3,380
Total cost of revenue	1,912	3,466
Operating (income) expense	(40)	11
Loss from operations	(44)	(97)
Interest expense	177	378
Other (income) expense, net	(15)	2
Reorganization items	382	485
Provision (benefit) for income taxes	(25)	70
Net loss	$ (563)	$ (1,032)

Condensed Combined Statement of Cash Flows

	Six Months Ended June 30, 2007
Net cash provided by (used in):	
Operating activities	$ (306)
Investing activities	348
Financing activities	309
Net increase in cash and cash equivalents	351
Cash and cash equivalents, beginning of period	883
Cash and cash equivalents, end of period	$ 1,234
Net cash paid for reorganization items included in operating activities	$ 65
Net cash received from reorganization items included in investing activities	$ (248)
Net cash paid for reorganization items included in financing activities	$ 52

3. Property, Plant and Equipment, Net

As of June 30, 2008, and December 31, 2007, the components of property, plant and equipment are stated at cost less accumulated depreciation as follows (in millions):

	June 30, 2008	December 31, 2007
Buildings, machinery and equipment	$ 13,459	$ 13,439
Geothermal properties	958	944
Other	260	259
	14,677	14,642
Less: Accumulated depreciation	(2,786)	(2,582)
	11,891	12,060
Land	74	77
Construction in progress	166	155
Property, plant and equipment, net	$ 12,131	$ 12,292

4. Investments

At June 30, 2008, and December 31, 2007, our investments included the following (in millions):

	Ownership Interest as of June 30, 2008	June 30, 2008	December 31, 2007
Greenfield LP	50%	$ 80	$ 114
OMEC	100%	159	146
RockGen	100%	138	—
Whitby	50%	9	—
Total investments		$ 386	$ 260

Greenfield LP — Greenfield LP is a limited partnership between certain subsidiaries of ours and of Mitsui & Co., Ltd., formed for the purpose of constructing and operating 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. Our investment is accounted for under the equity method. On May 31, 2007, Greenfield LP entered into a Can$648 million non-recourse project finance facility, which is structured as a construction loan that will convert to an 18-year term loan once the power plant begins commercial operations. Borrowings under the project finance facility are initially priced at Canadian LIBOR plus 1.2% or Canadian prime rate plus 0.2%. During the three and six months ended June 30, 2008 and 2007, we contributed nil and $30 million, respectively, and nil and $68 million, respectively, as an additional investment in Greenfield LP. During the three and six months ended June 30, 2008, we received nil and $24 million in distributions from Greenfield LP, respectively. We received no distributions during the three and six months ended June 30, 2007.

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. We deconsolidated OMEC during the second quarter of 2007 as described further in Note 1. Our investment is accounted for under the equity method. On May 3, 2007, OMEC entered into a $377 million non-recourse project finance facility to finance the construction of the Otay Mesa power plant. The project finance facility is structured as a construction loan, converting to a term loan upon commercial operation of the Otay Mesa power plant, and matures in April 2019. Borrowings under the project finance facility are initially priced at LIBOR plus 1.5%. During the three and six months ended June 30, 2008 and 2007, we contributed $9 million and nil, respectively, and $9 million and nil, respectively, as an additional investment in OMEC.

RockGen — RockGen, an indirect wholly owned subsidiary, is the owner of the RockGen Energy Center. We deconsolidated RockGen during the first quarter of 2008, as described further in Note 1. Our investment is accounted for under the equity method.

Whitby — Represents our 50% investment in Whitby held by our Canadian subsidiaries, which was reconsolidated on the Canadian Effective Date. Our investment is accounted for under the equity method.

Our income (loss) from our unconsolidated investments in power plants is included in other operating (income) expense on our Consolidated Condensed Statements of Operations. For the three and six months ended June 30, 2008 and 2007, our income from unconsolidated investments in power plants was $16 million and $13 million, respectively, and nil and nil, respectively.

5. 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 of certain liabilities. We recorded a pre-tax gain of approximately $63 million in the first quarter of 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 of certain liabilities. We recorded a pre-tax gain of approximately $136 million in the first quarter of 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 operate or were located; therefore, the results of operations for all periods prior to sale are included in our continuing operations.

Assets Held for Sale — There were no assets held for sale as of June 30, 2008. At December 31, 2007, our current assets held for sale consisted of construction in progress of the Fremont and Hillabee development projects totaling $195 million.

6. Comprehensive Income (Loss)

Comprehensive income (loss) is the total of net income (loss) and all other non-owner changes in equity. Comprehensive income (loss) includes our net income (loss), unrealized gains and losses from derivative instruments 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) (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Net income (loss)	$ 197	$ (500)	$ (17)	$ (959)
Other comprehensive income (loss):				
Gain (loss) on cash flow hedges before reclassification adjustment	(168)	8	(572)	(5)
Reclassification adjustment	12	19	22	29
Foreign currency translation loss	—	(11)	(6)	(11)
Provision for income taxes	(4)	(9)	(4)	(9)
Total comprehensive income (loss)	$ 37	$ (493)	$ (577)	$ (955)

7. Debt

Our debt at June 30, 2008, and December 31, 2007, was as follows (in millions):

	June 30, 2008	December 31, 2007
Exit Credit Facility	$ 6,475	$ —
DIP Facility	—	3,970
Second Priority Debt	—	3,672
Construction/project financing	2,050	1,944
CCFC financing	779	780
Preferred interests	414	575
Notes payable and other borrowings	413	432
Capital lease obligations	281	283
Total debt[1]	10,412	11,656
Less: Current maturities	308	1,710
Debt, net of current portion[1]	$ 10,104	$ 9,946

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(1) Our debt balances at December 31, 2007, do not include $3.7 billion in debt that was classified as LSTC. These balances were settled upon our emergence from Chapter 11 on the Effective Date. See Note 2 of the Notes to Consolidated Condensed Financial Statements for a further discussion of our emergence from Chapter 11.

Exit Facilities — Upon our emergence from Chapter 11, we converted the approximately $4.9 billion of loans and commitments outstanding under our DIP Facility (including the $1.0 billion revolver) into loans and commitments under our approximately $7.3 billion of Exit Facilities. The Exit Facilities provide for approximately $2.1 billion in senior secured term loans and $300 million in senior secured bridge loans in addition to the loans and commitments that had been available under the DIP Facility. The Exit Facilities include:

- The Exit Credit Facility, comprising (i) approximately $6.0 billion of senior secured term loans; (ii) a $1.0 billion senior secured revolving facility; and (iii) the ability 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; and

- The Bridge Facility, which, prior to its repayment as described below, provided for a $300 million senior secured bridge term loan.

The approximately $6.0 billion of senior secured term loans and the $300 million Bridge Facility were fully drawn and we drew approximately $150 million under the $1.0 billion senior secured revolving facility on the Effective Date. The proceeds of the drawdowns, above the amounts that had been applied under the DIP Facility as described below, were used to repay a portion of the Second Priority Debt, fund distributions under the Plan of Reorganization to holders of other secured claims and to pay fees, costs, commissions and expenses in connection with the Exit Facilities and the implementation of our Plan of Reorganization. Term loan borrowings under the Exit Credit Facility bear interest at a floating rate of, at our option, 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, with the remaining unpaid amount due and payable at maturity on March 29, 2014.

As of March 6, 2008, the Bridge Facility had been repaid in full in accordance with its terms with proceeds from the sales of the Hillabee and Fremont development project assets. Prior to repayment, borrowings under the Bridge Facility bore interest at LIBOR plus 2.875% per annum.

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 covenant restrictions, including limiting our ability to, among other things: (i) incur additional indebtedness and issue stock; (ii) make prepayments on or purchase indebtedness in whole or in part; (iii) pay dividends and other distributions with respect to our stock or repurchase our stock or make other restricted payments; (iv) use money borrowed under the Exit Credit Facility for non-guarantors (including foreign subsidiaries); (v) make certain investments; (vi) create or incur liens to secure debt; (vii) consolidate or merge with another entity, or allow one of our subsidiaries to do so; (viii) lease, transfer or sell assets and use proceeds of permitted asset leases, transfers or sales; (ix) limit dividends or other distributions from certain subsidiaries up to Calpine; (x) make capital expenditures beyond specified limits; (xi) engage in certain business activities; and (xii) acquire facilities or other businesses.

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

As of June 30, 2008, under the Exit Credit Facility we had approximately $6.0 billion outstanding under the term loan facilities, $525 million outstanding under the revolving credit facility and $254 million of letters of credit issued against the revolving credit facility.

DIP Facility — As of December 31, 2007, our primary debt facility was the DIP Facility. The DIP Facility consisted of a $4.0 billion first priority senior secured term loan and a $1.0 billion first priority senior secured revolving credit facility together with an uncommitted term loan facility that permitted us to raise up to $2.0 billion of incremental term loan funding on a senior secured basis with the same priority as the then current debt under the DIP Facility. In addition, under the DIP Facility, the U.S. Debtors had the ability to provide liens to counterparties to secure obligations arising under certain hedging agreements. The DIP Facility bore interest at LIBOR plus 2.25% or base rate plus 1.25% and matured upon the Effective Date, when the loans and commitments under the DIP Facility were converted to loans and commitments under our Exit Facilities.

Other Financing Activities — On February 1, 2008, Blue Spruce entered into a $90 million senior term loan. Net proceeds from the senior term loan were used to refinance all outstanding indebtedness under the existing Blue Spruce term loan facility, to pay fees and expenses related to the transaction and for general corporate purposes. The senior term loan carries interest at LIBOR plus an initial base rate of 1.63%, which escalates to 2.50% over the life of the senior term loan and matures December 31, 2017. The senior term loan is secured by the assets of Blue Spruce. In connection with this refinancing, we recorded $7 million in loss on debt extinguishment, related to the write-off of deferred financing costs of $4 million and breakage costs of $3 million, which are recorded in other (income) expense, net on our Consolidated Condensed Statements of Operations.

During the first quarter of 2008, we entered into a letter of credit facility related to our subsidiary Calpine Development Holdings, Inc. under which up to $150 million is available for letters of credit. As of June 30, 2008, $115 million in letters of credit had been issued under this facility.

On June 10, 2008, Metcalf closed on a $265 million new term loan facility. The proceeds were used to repay Metcalf's existing $100 million term loan facility and $155 million preferred interests. The new term loan facility, which matures on June 10, 2015, bears interest at Metcalf's option at LIBOR plus 3.25% or base rate plus 2.25% and is secured by the assets of Metcalf and the sole member interest held by Metcalf's parent, Metcalf Holdings, LLC. In connection with this refinancing, we recorded $6 million in loss on debt extinguishment, related to the write-off of deferred financing costs of $3 million and breakage costs of $3 million, which are recorded in other (income) expense, net on our Consolidated Condensed Statements of Operations.

On June 25, 2008, we entered into the Knock-in Facility, a 12-month, $200 million letter of credit facility. Our obligations under the Knock-in Facility are unsecured. Availability of letters of credit for issuance under the Knock-in Facility is up to a total maximum availability of $200 million contingent on natural gas futures contract prices exceeding certain thresholds, with initial availability for up to $50 million. As of June 30, 2008, no letters of credit had been issued under this facility.

At June 30, 2008, we had a total of $476 million in amounts outstanding under letters of credit including $254 million under our Exit Credit Facility and $115 million under the letter of credit facility related to our subsidiary Calpine Development Holdings, Inc., each discussed above, as well as amounts outstanding under other credit facilities. At December 31, 2007, we had a total of $298 million in letters of credit outstanding under our DIP Facility and other credit facilities.

On July 8, 2008, we entered into the Commodity Collateral Revolver, a two-year, $300 million secured revolving credit facility which shares the benefits of the collateral subject to the liens under the Exit Credit Facility ratably with the lenders under the Exit Credit Facility. At closing, we borrowed an initial advance of $100 million. Future advances under the Commodity Collateral Revolver are limited to the lesser of $300 million and the MTM Exposure (as defined in the Commodity Collateral Revolver) under certain reference transactions, less the advanced amount then outstanding. Amounts borrowed under the Commodity Collateral Revolver are to be used to collateralize obligations to counterparties under eligible commodity hedge agreements. The Commodity Collateral Revolver bears interest at LIBOR plus 2.875% per annum. Advances may be repaid prior to the maturity date, in whole or in part, provided that partial payment shall not reduce the aggregate outstanding advances to less than $100 million. Repayments made prior to the maturity date that do not reduce the total available commitment amount are subject to a 5% premium (plus breakage costs, if any).

Both the Knock-in Facility and Commodity Collateral Revolver contain covenant restrictions and require compliance with financial covenants substantially equivalent to those under the Exit Credit Facility.

8. Fair Value Measurements

Effective January 1, 2008, we adopted SFAS No. 157, which provides a framework for measuring fair value under GAAP and, among other things, requires enhanced disclosures about assets and liabilities carried at fair value. As defined in SFAS No. 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in the principal or most advantageous market in an orderly transaction between market participants at the measurement date (exit price). We utilize market data 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. 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. SFAS No. 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurement) and the lowest priority to unobservable inputs (level 3 measurement). The three levels of the fair value hierarchy defined by SFAS No. 157 are as follows:

Level 1 — Quoted prices (unadjusted) are available in active markets for identical assets or liabilities as of the reporting date. Active markets are those in which transactions for the asset or liability occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2 — Pricing inputs include quoted prices for similar assets and liabilities in active markets, and inputs that are observable for the asset or liability, either directly or indirectly, for substantially the full term of the financial instrument.

Level 3 — Pricing inputs include significant inputs that are generally less observable or from unobservable sources. These inputs may be used with internally developed methodologies that result in management’s best estimate of fair value.

SFAS No. 157 is to be applied prospectively as of the beginning of the year of adoption, except for limited retrospective application to selected items including financial instruments that were measured at fair value using the transaction price in accordance with the requirements of EITF Issue No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities." Day one gains and losses previously deferred under EITF Issue No. 02-3 should be recorded as a cumulative effect adjustment to opening retained earnings at the date of adoption. As of January 1, 2008, we recorded a non-cash reduction to retained earnings of approximately $22 million relating to the unamortized deferred loss on a derivative instrument. The determination of the fair value incorporates various factors required under SFAS No. 157. These factors include not only the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits and first priority liens) but also the impact of our nonperformance risk on our liabilities.

Prices for electricity and natural gas are volatile, which can result in material changes in the fair value measurements reported in our Consolidated Condensed Financial Statements in the future. 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 electricity and natural gas, the credit standing of our counterparties and our own credit rating.

Derivatives — We enter into a variety of derivative instruments to include both exchange traded and OTC power and gas forwards, options and interest rate swaps.

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

Our level 2 fair value derivative instruments primarily consist of our interest rate swaps and our power and gas OTC 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 power and gas OTC 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 SFAS No. 157 and include in level 3 all of those whose fair value is based on significant unobservable inputs.

When assessing nonperformance risk, the fair value of our derivatives include the credit standing of the counterparties involved and the impact of credit enhancements, if any. Such valuation adjustments are generally based on market evidence, if available, or management's best estimate.

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2008. As required by SFAS No. 157, 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, 2008			
	Level 1	Level 2	Level 3	Total
	(in millions)			
Assets:				
Commodity derivatives	$ 1,712	$ 777	$ 3,202	$ 5,691
Interest rate derivatives	—	56	—	56
Total derivative assets	1,712	833	3,202	5,747
Margin deposits[1]	696	—	—	696
Total	$ 2,408	$ 833	$ 3,202	$ 6,443
Liabilities:				
Commodity derivatives	$ (1,510)	$ (988)	$ (3,851)	$ (6,349)
Interest rate derivatives	—	(166)	—	(166)
Total derivative liabilities	(1,510)	(1,154)	(3,851)	(6,515)
Margin held by us posted by our counterparties[1]	(86)	—	—	(86)
Total	$ (1,596)	$ (1,154)	$ (3,851)	$ (6,601)

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(1) Margin deposits and margin held by us posted by our counterparties represent cash collateral paid between us and our counterparties to support our derivative 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 cash flow 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 derivatives classified as level 3 in the fair value hierarchy (in millions):

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

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(1) Reflects our portfolio of derivative assets and liabilities as of December 31, 2007, adjusted for the day one loss of $(22) million recognized upon adoption of SFAS No. 157 on January 1, 2008.

(2) Includes $3 million and $(174) million recorded in operating revenues (for electricity contracts) and $104 million and $21 million recorded in fuel and purchased energy expense (for gas contracts) for the three and six months ended June 30, 2008, respectively, as shown on our Consolidated Condensed Statements of Operations.

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

(4) Includes $3 million and $(201) million recorded in operating revenues (for electricity contracts) and $104 million and $44 million recorded in fuel and purchased energy expense (for gas contracts) for the three and six months ended June 30, 2008, respectively, as shown on our Consolidated Condensed Statements of Operations.

9. Derivative Instruments and Mark-to-Market Activity

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

	Interest Rate Swaps	Commodity Instruments	Total Derivative Instruments
Current derivative assets	$ 5	$ 5,048	$ 5,053
Long-term derivative assets	51	643	694
Total derivative assets	$ 56	$ 5,691	$ 5,747
Current derivative liabilities	$ 106	$ 5,380	$ 5,486
Long-term derivative liabilities	60	969	1,029
Total derivative liabilities	$ 166	$ 6,349	$ 6,515
Net derivative liabilities	$ (110)	$ (658)	$ (768)

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 gas agreements that qualify as "eligible commodity hedge agreements" under the Exit Credit Facility and under 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 will share the benefits of the collateral subject to such first priority liens ratably with the lenders under the Exit Credit Facility.

Such first priority liens had also been permitted under the DIP Facility prior to the conversion of the loans and commitments under the DIP Facility to our exit financing under the Exit Credit Facility.

The table below summarizes the balances outstanding under margin deposits, 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, 2008 (in millions):

	June 30, 2008
Margin deposits	$ 696
Gas and power prepayments	113
Total margin deposits and gas and power prepayments with our counterparties[1]	$ 809
Letters of credit issued	$ 376
First priority liens under power and natural gas agreements	421
First priority liens under interest rate swap agreements	92
Total letters of credit and first priority liens with our counterparties	$ 889
Margin deposits posted with us by our counterparties[2]	$ 86
Letters of credit posted with us by our counterparties	6
Total margin deposits and letters of credit posted with us by our counterparties	$ 92

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(1) Included in margin deposits and other prepaid expense and in other assets on our Consolidated Condensed Balance Sheet.

(2) Included in other current liabilities on our Consolidated Condensed Balance Sheet.

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

We did not elect to adopt the netting provisions allowed under FSP FIN 39-1, which allows an entity to offset the fair value amounts recognized for cash collateral paid or cash collateral received against the fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement. As of June 30, 2008, we had $599 million in rights to claim cash collateral and $86 million in obligations to return cash collateral that are subject to master netting agreements.

The table below details the components of our total mark-to-market activity and where they are recorded on our Consolidated Condensed Statements of Operations (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Power contracts included in operating revenues	$ (8)	$ 147	$ (104)	$ 135
Gas contracts included in fuel and purchased energy expense	32	(94)	(23)	(141)
Interest rate swaps included in interest expense	12	10	(4)	9
Total mark-to-market activity	$ 36	$ 63	$ (131)	$ 3

Hedge ineffectiveness is included in unrealized mark-to-market gains and losses. Gains (losses) due to ineffectiveness on commodity hedging instruments were $(1) million for the three months ended June 30, 2008 and 2007, and $5 million and $1 million for the six months ended June 30, 2008 and 2007, respectively.

Below is a reconciliation of our net derivative liabilities to our accumulated other comprehensive loss, net of tax from derivative instruments at June 30, 2008 (in millions):

	June 30, 2008
Net derivative liabilities	$ (768)
Derivatives not designated as cash flow hedges and recognized hedge ineffectiveness	13
Equity investment OCI	(19)
Cash flow hedges terminated prior to maturity	(28)
Cumulative OCI tax benefit	7
Accumulated other comprehensive loss from derivative instruments, net of tax[(1)]	$ (795)

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(1) Amount represents one portion of our total AOCI balance of $(791) million.

Where we have derivatives designated as cash flow or fair value hedges we present the cash flows from these derivatives in the same category as the item being hedged on our Consolidated Condensed Statements of Cash Flows. The realized components of interest rate swaps and the cash flows for our derivatives not designated as hedges are classified in operating activities on our Consolidated Condensed Statements of Cash Flows. Derivatives related to Deer Park, which contain an other than significant financing element, are classified within financing activities on our Consolidated Condensed Statements of Cash Flows.

The table below reflects the contribution of our cash flow hedge activity to pre-tax earnings (losses) based on the reclassification adjustment from AOCI to earnings (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
Natural gas derivatives	$ 135	$ (9)	$ 113	$ (15)
Power derivatives	(119)	(7)	(105)	(4)
Interest rate derivatives	(28)	(3)	(30)	(10)
Total derivatives	$ (12)	$ (19)	$ (22)	$ (29)

As of June 30, 2008, the maximum length of time over which we were hedging our exposure to the variability in future cash flows for forecasted transactions was 5 and 11 years for commodity and interest rate derivative instruments, respectively. We currently estimate that pre-tax losses of $567 million would be reclassified from AOCI into earnings during the twelve months ending June 30, 2009, as the hedged transactions affect earnings assuming constant gas and power prices and interest rates over time; however, the actual amounts that will be reclassified will likely vary based on changes in gas and power prices as well as interest rates. Therefore, management is unable to predict what the actual reclassification from AOCI to earnings (positive or negative) will be for the next twelve months.

The table below presents the pre-tax gains (losses) currently held in AOCI that will be recognized annually into earnings, assuming constant gas and power prices and interest rates over time (in millions):

	2008	2009	2010	2011	2012	Thereafter	Total
Natural gas derivatives	$ 333	$ 154	$ 27	$ 22	$ 21	$ —	$ 557
Power derivatives	(631)	(509)	(35)	(25)	(23)	—	(1,223)
Interest rate derivatives	(47)	(65)	(12)	4	(15)	(1)	(136)
Total pre-tax AOCI	$ (345)	$ (420)	$ (20)	$ 1	$ (17)	$ (1)	$ (802)

10. 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. In addition, approximately 2 million restricted shares of reorganized Calpine Corporation common stock were issued pursuant to the Calpine Equity Incentive Plans, net of forfeitures. 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 under SFAS No. 128 "Earnings per Share" and are included in our calculation of weighted average shares outstanding.

Reconciliations of the amounts used in the basic and diluted earnings (loss) per common share computations are:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008	2007	2008	2007
	(shares in thousands)			
Diluted weighted average shares calculation:				
Weighted average shares outstanding (basic)	485,004	479,175	485,002	479,155
Restricted stock awards	723	—	—	—
Employee stock options	5	—	—	—
Weighted average shares outstanding (diluted)	485,732	479,175	485,002	479,155

As we incurred net losses during the six months ended June 30, 2008, and three and six months ended June 30, 2007, 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. Potentially dilutive securities excluded from our calculation of diluted loss per share for the three months ended June 30, 2008, consist of anti-dilutive shares from employee stock options, common stock warrants and restricted stock. See Note 11 for a discussion of our stock-based compensation and Note 2 for a discussion of our common stock warrants.

As discussed in Note 2, all shares of our common stock outstanding prior to the Effective Date were canceled pursuant to the Plan of Reorganization and new shares of reorganized Calpine Corporation common stock were issued. Although loss per share information for the three and six months ended June 30, 2007, is presented, it is not comparable to the information presented for the three and six months ended June 30, 2008, due to the changes in our capital structure on the Effective Date, which also included termination of all outstanding convertible securities.

11. Stock-Based Compensation

Calpine Equity Incentive Plans — 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 reorganized Calpine Corporation common stock available for issuance to participants.

The equity awards granted during the six months ended June 30, 2008, vest over periods between one and three years, contain contractual terms of ten years and are subject to forfeiture provisions under certain circumstances including termination of employment prior to vesting. Stock-based compensation expense (income) recognized was $13 million and $1 million for the three months ended June 30, 2008 and 2007, respectively, and $19 million and $(1) million for the six months ended June 30, 2008 and 2007, respectively. At June 30, 2008, there was $48 million of unrecognized compensation cost related to equity awards, which is expected to be recognized over a weighted-average period of 1.2 years for options, 1.5 years for restricted shares and 0.7 years for restricted stock units.

A summary of our non-qualified stock option activity for the MEIP and DEIP for the six months ended June 30, 2008, is as follows:

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Term (in years)	Aggregate Intrinsic Value (in millions)
Outstanding – December 31, 2007	—	$ —		
Granted	5,281,300	$ 17.54		
Exercised	—	$ —		
Forfeited	577,100	$ 17.12		
Expired	—	$ —		
Outstanding – June 30, 2008	4,704,200	$ 17.59	9.5	$ 23
Exercisable – June 30, 2008	3,200	$ 17.64	0.8	$ —
Vested and expected to vest – June 30, 2008	4,425,194	$ 17.58	9.5	$ 22

The fair value of options granted was determined on the grant date using the Black-Scholes pricing model. Certain assumptions were used in order to estimate fair value for options granted during the six months ended June 30, 2008, as noted in the following table. No options were granted during the six months ended June 30, 2007.

	June 30, 2008
Expected term (in years)[(1)]	5.4 – 6.1
Risk-free interest rate[(2)]	2.7 – 3.3%
Expected volatility[(3)]	34.8 – 40.9%
Dividend yield	—
Weighted average grant-date fair value (per option)	$ 7.22

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(1) Expected term calculated using the simplified method under SAB 110 “Shared-Based Payment.”

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

(3) Volatility calculated using the weighted average implied volatility of our industry peers’ exchange traded stock options.

A summary of our restricted stock and restricted stock unit activity for the MEIP and DEIP for the six months ended June 30, 2008, is as follows:

	Number of Restricted Stock Awards	Weighted Average Grant-Date Fair Value
Nonvested – December 31, 2007	—	$ —
Granted	2,733,352	$ 16.71
Forfeited	608,529	$ 16.50
Vested	1,100	$ 16.80
Nonvested – June 30, 2008	2,123,723	$ 16.77

On March 25, 2008, we amended the employment agreement with our Chief Executive Officer, Mr. Robert P. May. Under the terms of the amendment, Mr. May agreed to forfeit his right to 348,700 non-qualified stock options with an exercise price of $16.90 granted on January 31, 2008, as well as 474,600 shares of restricted stock granted on February 6, 2008, both of which were to vest ratably over periods of approximately 1.5 years and 3 years. In exchange for canceling these non-qualified stock options and restricted stock, on March 25, 2008, we granted Mr. May 325,500 non-qualified stock options with an exercise price of $17.53 (which equaled the closing price of our common stock on the date of grant) and modified the vesting terms on 73,000 shares of restricted stock. The awards granted and modified on March 25, 2008, vest in their entirety on December 31, 2008. Both of these changes to Mr. May's non-qualified stock options and restricted stock awards were accounted for as Type III modifications under the provisions of SFAS No. 123(R) "Share-Based Payment." Under this scenario, we deemed that Mr. May's vesting condition under his original grant was not probable of achievement on the modification date and, thus, the original grant date fair value is no longer used to measure compensation cost. The modification date fair value of the new awards is used to measure compensation cost which is being expensed over the modified vesting term.

12. Commitments and Contingencies

Potential Loss on Deconsolidation/Sale of Auburndale Power Plant — Auburndale, our consolidated subsidiary, is a variable interest entity. Pomifer, an unrelated party, holds a preferred interest in Auburndale, which entitles Pomifer to approximately 70% of Auburndale's cash distributions through 2013. Pomifer also has an option which, upon exercise, would entitle Pomifer to an additional cash distribution of 20% for a cash strike price, giving Pomifer a right to a total of approximately 90% of Auburndale's cash distributions through 2013. In August 2008, Pomifer notified us that it intends to exercise its option to increase its share of cash distributions to 90%. Pomifer's exercise of this option may result in a determination that we no longer absorb the majority of expected losses and residual returns of Auburndale, such that we no longer are the primary beneficiary of Auburndale. If we determine that we are no longer the primary beneficiary of Auburndale, we will be required to deconsolidate Auburndale at the time Pomifer exercises its option.

In addition, on June 3, 2008, Pomifer notified us of its intent to sell its preferred interest in Auburndale and that it had also initiated a third-party sales process requesting bids for 100% of Auburndale. Pomifer has certain "drag-along" rights over our equity interest in Auburndale, which would require us to sell our equity interest in Auburndale for a cash payment as specified in our agreement with Pomifer. If Pomifer exercises its drag-along rights and we are required to sell our entire remaining equity interest in Auburndale to a third party, we expect that we would be required to record a loss in the amount of our equity interests in Auburndale of approximately $200 million, less any proceeds we would receive related to the sale. This impairment could be material.

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. 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. 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. 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 Calpine Debtors generally were stayed. See Note 2 for information regarding our Chapter 11 cases and CCAA proceedings. 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. 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.

Pre-Petition Litigation

Hawaii Structural Ironworkers Pension Fund v. Calpine, et al. This case was filed in San Diego County Superior Court on March 11, 2003, and later transferred, on a defense motion, to 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 in the Santa Clara County Superior Court was stayed against Calpine Corporation as a result of 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 in the Santa Clara County Superior Court. Calpine Corporation remains a defendant to the action. However, 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 against Calpine Corporation 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 any insurance coverage that may be available to Calpine Corporation. 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. Fact discovery is scheduled to close on October 6, 2008. No trial date has been set in this action. We consider this lawsuit to be without merit and intend to continue to defend vigorously against the allegations.

In re Calpine Corp. ERISA Litig. Two nearly identical class action complaints alleging claims under ERISA (*Phelps v. Calpine Corporation, et al.* and *Lenette Poor-Herena v. Calpine Corporation et al.*) were consolidated under the caption *In re Calpine Corp. ERISA Litig.*, Master File No. C 03-1685 SBA, in the Northern District Court. Plaintiff Poor-Herena subsequently dropped her claim. The consolidated complaint, which names as defendants Calpine Corporation, the members of Calpine Corporation's Board of Directors, the 401(k) Plan's Advisory Committee and its members, signatories of the 401(k) Plan's Annual Return/Report of Employee Benefit Plan Forms 5500 for 2001 and 2002, an employee of a consulting firm hired by the 401(k) Plan, and unidentified fiduciary defendants, alleged claims under ERISA on behalf of the participants in the 401(k) Plan from January 5, 2001, to the present who invested in the Calpine unitized stock fund. The consolidated complaint alleged that defendants breached their fiduciary duties under ERISA by permitting participants to buy and hold interests in the Calpine unitized stock fund. All claims were dismissed with prejudice by the Northern District Court. The plaintiff appealed the dismissal to the Ninth Circuit Court of Appeals. As a result of the Chapter 11 filings, the appeal was automatically stayed with respect to Calpine Corporation. In addition, Calpine Corporation filed a motion with the U.S. Bankruptcy Court to extend the automatic stay to the individual defendants. Plaintiff opposed the motion and a hearing was scheduled for June 5, 2006; however, prior to the hearing, the parties stipulated to allow the appeal to the Ninth Circuit Court of Appeals to proceed. If the Northern District Court ruling is reversed, the plaintiff may then seek leave from the U.S. Bankruptcy Court to proceed with the action. Plaintiff's opening brief was filed with the Ninth Circuit Court of Appeals on November 6, 2006. Further briefing on the appeal was then stayed pending completion of the parties' participation in the Ninth Circuit Court of Appeal's alternative dispute resolution program. On March 21, 2007, the parties reached an agreement in principle to settle the claims of plaintiff and the purported class in return for a payment of approximately $4 million by Calpine's fiduciary insurance carrier, the net proceeds of which will ultimately be deposited into individual plan members' accounts. The parties finalized the settlement agreement on March 7, 2008. Pursuant to the terms of the settlement, the Ninth Circuit Court of Appeals dismissed plaintiff's appeal without prejudice and remanded the case to the Northern District Court by order dated April 8, 2008. The settlement remains subject to approval by the Northern District Court. The Northern District Court granted preliminary approval on July 17, 2008, and has scheduled a fairness hearing for October 21, 2008, to consider whether to give final approval to the settlement.

Panda Energy International, Inc., et al. v. Calpine Corporation, et al. On November 5, 2003, Panda filed suit in the U.S. District Court, Northern District of Texas against Calpine Corporation and certain of its affiliates alleging, among other things, that defendants breached duties of care and loyalty allegedly owed to Panda by failing to correctly construct and operate the Oneta Energy Center, the development rights of which we had acquired from Panda, in accordance with Panda's original plans. Panda alleges that it is entitled to a portion of the profits of the Oneta Energy Center and that the defendant's actions have reduced the profits from Oneta Energy Center thereby undermining Panda's ability to repay monies owed to Calpine Corporation on December 1, 2003, under a promissory note on which approximately $54 million (including related interest) was outstanding as of June 30, 2008. Calpine Corporation has filed a counterclaim against Panda and related parties based on a guaranty and loan agreement. Trial was set for May 22, 2006, but did not proceed due to the automatic stay. Calpine Corporation filed a motion on October 3, 2007, to lift the automatic stay to pursue its counterclaim. On November 14, 2007, the U.S. Bankruptcy Court granted the motion, lifting the automatic stay. On January 30, 2008, the U.S. District Court issued an order that re-instated the case on the court's docket. Panda has recently amended its pleadings in the U.S. District Court to allege certain causes of action against Calpine Corporation relating to the contingent net profit interest which it has alleged are post-petition. In February 2008, the Panda entities filed proofs of claim with the U.S. Bankruptcy Court asserting an unsecured claim in the amount of approximately $200 million as rejection damages under the development rights and other agreements. Calpine Corporation objected to the claims in the U.S. Bankruptcy Court. The U.S. Bankruptcy Court held a hearing on Calpine Corporation's claim objection on July 31, 2008. On August 4, 2008, the Bankruptcy Court issued an order disallowing all proofs of claim filed by Panda against the estate. Mediation was conducted on August 5, 2008, without success. The case is set for trial in January 2009 in the U.S. District Court for the Northern District of Texas. We consider Panda's lawsuit and proofs of claim to be without merit and intend to continue to vigorously defend against them in the U. S. District Court and the U. S. Bankruptcy Court.

Harbert Convertible Arbitrage Master Fund, Ltd. et al. v. Calpine Corporation. Plaintiff Harbert Convertible Fund and two affiliated funds filed this action on July 11, 2005, in the New York County Supreme Court, and filed an amended complaint on July 19, 2005. In their amended complaint, plaintiffs alleged that in a July 5, 2005, letter to Calpine Corporation they provided "reasonable evidence" as required under the indenture governing the 2014 Convertible Notes that, on one or more days beginning on July 1, 2005, the trading price of the 2014 Convertible Notes was less than 95% of the product of the common stock price multiplied by the conversion rate, as those terms are defined in the 2014 Convertible Notes indenture, and that Calpine Corporation therefore was required to instruct the bid solicitation agent for the 2014 Convertible Notes to determine the trading price beginning on the next trading day. If the trading price as determined by the bid solicitation agent was below 95% of the product of the common stock price multiplied by the conversion rate for the next five consecutive trading days, then the 2014 Convertible Notes would become convertible into cash and common stock for a limited period of time. Plaintiffs have asserted a claim for breach of contract, seeking unspecified damages, because Calpine Corporation did not instruct the bid solicitation agent to begin to calculate the trading price. In addition, plaintiffs sought a declaration that Calpine had a duty, based on the statements in the letter dated July 5, 2005, to commence the bid solicitation process, and also sought injunctive relief to force Calpine Corporation to instruct the bid solicitation agent to determine the trading price of the 2014 Convertible Notes. On November 18, 2005, Harbert Convertible Fund filed a second amended complaint for breach and anticipatory breach of indenture, which also added the 2014 Convertible Notes trustee as a plaintiff.

The treatment provided to the holders of the 2014 Convertible Notes under the Plan of Reorganization was in full satisfaction, settlement, release, and discharge of any claims related to the 2014 Convertible Notes. Accordingly, on April 16, 2008, the New York County Supreme Court discontinued this action with prejudice.

Whitebox Convertible Arbitrage Fund, L.P., et al. v. Calpine Corporation. Plaintiff Whitebox Convertible Arbitrage Fund, L.P. and seven affiliated funds filed an action in the New York County Supreme Court for breach of contract on October 17, 2004. The factual allegations and legal basis for the claims set forth in that action are nearly identical to those set forth in the Harbert Convertible Fund filings. On October 19, 2005, the Whitebox plaintiffs filed a motion for preliminary injunctive relief, but withdrew the motion on November 7, 2005. Whitebox had informed Calpine Corporation and the New York County Supreme Court that the trustee was considering intervening in the case and/or filing a similar action for the benefit of all holders of the 2014 Convertible Notes. The treatment provided to the holders of the 2014 Convertible Notes under the Plan of Reorganization was in full satisfaction, settlement, release, and discharge of any claims related to the 2014 Convertible Notes. Accordingly, on April 11, 2008, the New York County Supreme Court discontinued this action with prejudice.

Pit River Tribe, et al. v. Bureau of Land Management, et al. On June 17, 2002, Pit River filed suit 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 at Glass Mountain. It challenges the validity of the decisions of the BLM and the Forest Service to permit the development of the project under leases previously issued by the BLM. The lawsuit also sought to invalidate the leases. Only declaratory and equitable relief were sought. Our answer was submitted on August 20, 2002. Cross-motions for summary judgment on all claims in the lawsuit were submitted in May and June 2003. The court held oral argument on the motions on September 10, 2003, and took the motions under advisement. Defendants' motions for summary judgment were granted on February 13, 2004, and the lawsuit was dismissed. Plaintiff filed an appeal to the Ninth Circuit Court of Appeals on April 15, 2004. Briefing on the appeal was completed on December 6, 2004. Following our Chapter 11 filing, we and Pit River filed a stipulation with the U.S. Bankruptcy Court to lift the automatic stay to allow the appeal to proceed with oral arguments, which were held on February 14, 2006. On November 5, 2006, the Ninth Circuit Court of Appeals 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, when granting the lease extensions and, therefore, held that the lease extensions were invalid. On February 20, 2007, the federal appellees filed a Petition for Panel Rehearing of the November 5, 2006, order. We filed our Petition for Rehearing and Suggestion for Rehearing En Banc on February 21, 2007. On April 18, 2007, the Ninth Circuit Court of Appeals issued an order denying both the federal appellees and our Petitions for Rehearing. The remedy phase of the Ninth Circuit Court of Appeals' opinion had been stayed until Calpine Corporation's emergence from Chapter 11. Upon emergence from Chapter 11, we contacted the U.S. Department of Justice regarding possible remedies which could be argued to the District Court and prepared to file motions regarding how to implement the Ninth Circuit mandate. On August 4, 2008, the U.S. Department of Justice filed a Request to Reopen Case and Proposed Order to Implement Appellate Mandate. The proposed order would remand the procedural defects identified by the Ninth Circuit to the BLM to cure those defects and render a new decision whether or not to allow geothermal development at Glass Mountain, and if so, whether to extend Calpine Corporation's mineral leases. The U.S. District Court for the Eastern District adopted the U.S. Department of Justice's proposed briefing schedule and assigned a hearing date of November 5, 2008, for arguments on the proposed order.

In May 2004, 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. These two related cases had been stayed until emergence. Similar to above, we are now in communication with the U.S. Department of Justice and preparing to re-commence litigation.

Post-Petition Litigation

Chapter 11 Related Litigation

Appeal of Confirmation Order. The Confirmation Order was entered by the U.S. Bankruptcy Court on December 19, 2007. Two motions to reconsider the Confirmation Order were filed by holders of shares of our common stock that were canceled on the Effective Date: the first was filed on December 28, 2007, by Elias A. Felluss and the second on December 31, 2007, by Compania Internacional Financiera, S.A., Coudree Global Equities Fund, Standard Bank of London and Leonardo Capital Fund SPC. On January 15, 2008, the U.S. Bankruptcy Court entered an order denying both of the motions to reconsider. On January 18, 2008, the shareholders who had filed the December 31, 2007, motion filed a notice of appeal to the SDNY Court and moved the U.S. Bankruptcy Court for a stay of the Confirmation Order pending appeal. Various additional shareholders subsequently filed joinders to the stay motion in the U.S. Bankruptcy Court. On January 24, 2008, the U.S. Bankruptcy Court entered an order denying the stay motion. The shareholders who filed the December 31, 2007, motion filed an emergency motion with the SDNY Court on January 25, 2008, seeking to expedite their appeal and stay the Confirmation Order pending appeal; their emergency motion was denied by the SDNY Court on February 1, 2008. In the meantime, on January 28, 2008, additional shareholders filed notices of appeal to the SDNY Court. On January 31, 2008, the Plan of Reorganization became effective and we emerged from Chapter 11. Despite the effectiveness of the Plan of Reorganization, all of the appeals remained pending in the SDNY Court. On February 25, March 10, and March 14, 2008, the shareholder appellants filed their respective opening briefs. We filed a response on March 28, 2008, seeking to dismiss the appeals on grounds that (i) the appeals were equitably moot, (ii) the appellants had not made the threshold showing required to reverse the U.S. Bankruptcy Court; and (iii) the appeals all lack merit. The appellants filed their reply briefs on April 7, 2008. 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 United States Court of Appeals for the Second Circuit Court of Appeals.

Rosetta Avoidance Action. On June 29, 2007, Calpine Corporation filed a petition in the U.S. Bankruptcy Court against Rosetta for avoidance and recovery of a fraudulent transfer. In July 2005, Calpine Corporation had sold substantially all its remaining domestic oil and gas assets for $1.1 billion to a group led by Calpine Corporation insiders who constituted the management team of Rosetta, which prior to the sale, was a subsidiary of Calpine Corporation. The petition alleges that Rosetta's purchase of the domestic oil and natural gas assets prior to Calpine Corporation's Chapter 11 filing was for less than reasonably equivalent value. We are seeking monetary damages for the value Rosetta did not pay Calpine Corporation for the assets it acquired, plus interest, which is currently estimated to be approximately $490 million. However, discovery and further analysis may result in changes to that amount. In the alternative, we are seeking the return of the domestic oil and natural gas assets from Rosetta. On September 11, 2007, Rosetta filed a motion to dismiss the adversary proceeding or seek a stay of the proceeding, which the Court denied on October 24, 2007. On November 5, 2007, Rosetta filed its answer and six counterclaims, principally based on state contract and tort law. On January 4, 2008, we filed a motion to dismiss three of the six counterclaims as legally unsustainable. The Court has deferred ruling on our motion to dismiss counterclaims. Pre-trial document and deposition discovery is ongoing. No trial date has been set.

Non-Chapter 11 Related Litigation

Leone v. Calpine Corporation, et al. On May 22 and 29, 2008, respectively, two putative class action complaints (*Joseph Leone v. Calpine Corporation, et al. and Alan Laties v. Calpine Corporation, et al.*) were filed in state district court in Harris County, Texas against Calpine Corporation and its current directors, alleging that they either had breached, or would breach, their fiduciary duties in connection with Calpine Corporation's review of NRG Energy, Inc.'s proposal for a stock-for-stock merger on May 14, 2008. Both lawsuits named the same persons as defendants with the exception of Kenneth Derr, who was named only in the first-filed Leone action. In general, the lawsuits sought to enjoin the defendants from accepting the NRG proposal, a declaration that the defendants had breached their fiduciary duties in connection with the NRG proposal, rescission of a transaction based on the terms of the NRG proposal, a court order requiring the defendants to comply with their fiduciary duties, damages, attorneys' fees, expenses, and court costs. On June 4, 2008, the two lawsuits were consolidated into a single action. Defendants have not yet answered either lawsuit and are not obligated to do so until after plaintiffs file their consolidated amended class action petition in August 2008. Plaintiffs have filed a motion seeking their appointment as interim class representatives and their attorneys' appointment as interim class counsel. The court has not yet ruled on this motion. We consider this lawsuit to be without merit and intend to vigorously defend against it.

Kissa v. Calpine Corporation, et al. On May 27, 2008, Andrew J. Kissa filed a putative class action complaint in California Superior Court, County of Santa Clara, against Calpine Corporation and its directors. The complaint alleges, among other things, that the defendants violated their fiduciary duties to shareholders by negotiating with NRG, which sought to acquire us in a stock-for-stock merger. The complaint also alleges that the price offered by NRG was inadequate and unfair, and sought declaratory and injunctive relief directing the defendants to exercise their fiduciary duties to obtain a transaction in the best interests of Calpine Corporation's shareholders. On June 27, 2008, the defendants filed a demurrer to the complaint. On July 11, 2008, Kissa filed a request for dismissal of his complaint without prejudice, which was granted on July 24, 2008. We considered this lawsuit also to be without merit.

Other Post-Petition Matters

Texas City and Clear Lake Environmental Matters. As part of an internal review of our Texas City and Clear Lake Cogeneration power plants, we determined that our Acid Rain Program exemption under 40 CFR 72.6(b)(5) had ceased to apply and we were in violation of the requirements of the Acid Rain Program found in 40 CFR Parts 72-78. We were originally exempt from these provisions based upon each plant being a qualifying cogeneration facility in operation before November 1990 with qualifying Power Purchase Agreements; however, the exemptions ceased to apply in 2002 for Texas City and 1999 for Clear Lake. To remedy the violation, we are required to report our SO_2 emissions to the U.S. Environmental Protection Agency and purchase allowances and remit an excess emission fee for each ton over the allowance emitted since expiration of the exemption. We recorded estimated fees of $200,000 for Texas City and Clear Lake Cogeneration power plants, during the first quarter of 2008. We self-reported these violations and are working with the Texas Commission on Environmental Quality and the U.S. Environmental Protection Agency to resolve these matters in a timely manner. Although these agencies have the authority and discretion to issue substantial fines that could be material, we do not believe that the penalties, if any, resulting from these matters will have a material adverse effect on our business, financial condition or results of operations based upon our analysis of the facts and circumstances and consideration of recent cases addressed by the agencies involved.

Communications with the SEC. We have been contacted by and have 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 are cooperating with the SEC staff and have voluntarily provided information in response to their requests. We will continue to cooperate with the SEC with respect to these matters. A negative outcome of this investigation could require us to pay fines or penalties or satisfy other remedies under various provisions of the U.S. securities laws, and any of these outcomes could under certain circumstances have a material adverse effect on our business.

13. Segment Information

We operate in one line of business, the generation and sale of electricity and electricity-related products. 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, North and Other. Our Other segment includes fuel management, our turbine maintenance group, our PSM business for periods prior to its sale and certain hedging and other corporate activities.

Commodity margin includes our electricity and steam revenues, hedging and optimization activities, renewable energy credit revenue, transmission revenue and expenses, and fuel and purchased energy expense, but excludes mark-to-market commodity activity and other service revenues. Commodity margin is the key operational measure reviewed by our chief operating decision maker to assess the performance of our segments.

Financial data for our segments were as follows (in millions):

	Three Months Ended June 30, 2008						
	West	Texas	Southeast	North	Other	Consolidation and Elimination	Total
Revenues from external customers	$ 1,156	$ 1,185	$ 400	$ 170	$ (83)	$ —	$ 2,828
Intersegment revenues	12	75	59	6	3	(155)	—
Total revenue	$ 1,168	$ 1,260	$ 459	$ 176	$ (80)	$ (155)	$ 2,828
Commodity margin	340	258	91	72	24	—	785
Add: Mark-to-market commodity activity, net and other service revenues (1)	4	74	—	—	(40)	(3)	35
Less:							
Plant operating expense	95	48	22	24	22	(5)	206
Depreciation and amortization	44	33	18	13	1	(1)	108
Other cost of revenue	14	—	8	6	2	—	30
Gross profit (loss)	191	251	43	29	(41)	3	476
Other operating expense							43
Income from operations							433
Interest expense, net of interest income							192
Other (income) expense, net							1
Income before reorganization items and income taxes							240
Reorganization items							18
Income before income taxes							$ 222

	Three Months Ended June 30, 2007						
	West	Texas	Southeast	North	Other	Consolidation and Elimination	Total
Revenues from external customers	$ 806	$ 797	$ 294	$ 147	$ 16	$ —	$ 2,060
Intersegment revenues	8	1	50	1	2	(62)	—
Total revenue	$ 814	$ 798	$ 344	$ 148	$ 18	$ (62)	$ 2,060
Commodity margin	265	138	65	75	(8)	—	535
Add: Mark-to-market commodity activity, net and other service revenues (1)	3	48	8	—	13	(3)	69
Less:							
Plant operating expense	86	39	31	22	36	(3)	211
Depreciation and amortization	54	29	19	14	1	1	118
Other cost of revenue	13	—	8	9	4	(1)	33
Gross profit (loss)	115	118	15	30	(36)	—	242
Other operating expense							42
Income from operations							200
Interest expense, net of interest income							247
Other (income) expense, net							(9)
Loss before reorganization items and income taxes							(38)
Reorganization items							469
Loss before income taxes							$ (507)

	Six Months Ended June 30, 2008						
	West	Texas	Southeast	North	Other	Consolidation and Elimination	Total
Revenues from external customers	$ 2,118	$ 1,826	$ 657	$ 320	$ (142)	$ —	$ 4,779
Intersegment revenues	21	116	93	11	5	(246)	—
Total revenue	$ 2,139	$ 1,942	$ 750	$ 331	$ (137)	$ (246)	$ 4,779
Commodity margin	609	388	128	134	12	—	1,271
Add: Mark-to-market commodity activity, net and other service revenues (1)	14	41	1	—	(155)	(6)	(105)
Less:							
Plant operating expense	199	110	50	49	37	(7)	438
Depreciation and amortization	94	63	37	25	2	(2)	219
Other cost of revenue	30	—	16	12	4	—	62
Gross profit (loss)	300	256	26	48	(186)	3	447
Other operating expense							96
Income from operations							351
Interest expense, net of interest income							598
Other (income) expense, net							11
Loss before reorganization items and income taxes							(258)
Reorganization items							(261)
Income before income taxes							$ 3

	Six Months Ended June 30, 2007						
	West	Texas	Southeast	North	Other	Consolidation and Elimination	Total
Revenues from external customers	$ 1,604	$ 1,320	$ 501	$ 299	$ (2)	$ —	$ 3,722
Intersegment revenues	15	(2)	72	2	15	(102)	—
Total revenue	$ 1,619	$ 1,318	$ 573	$ 301	$ 13	$ (102)	$ 3,722
Commodity margin	495	224	102	138	(2)	—	957
Add: Mark-to-market commodity activity, net and other service revenues (1)	15	52	8	—	(21)	(16)	38
Less:							
Plant operating expense	165	68	55	38	58	(5)	379
Depreciation and amortization	105	60	42	27	2	—	236
Other cost of revenue	22	—	16	17	21	(6)	70
Gross profit (loss)	218	148	(3)	56	(104)	(5)	310
Other operating expense							91
Income from operations							219
Interest expense, net of interest income							530
Other (income) expense, net							(8)
Loss before reorganization items and income taxes							(303)
Reorganization items							574
Loss before income taxes							$ (877)

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(1) Mark-to-market commodity activity, net included in operating revenues and fuel and purchased energy expense.

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

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: (i) our ability to implement our business plan; (ii) financial results that may be volatile and may not reflect historical trends; (iii) seasonal fluctuations of our results and exposure to variations in weather patterns; (iv) potential volatility in earnings associated with fluctuations in prices for commodities such as natural gas and power; (v) our ability to manage liquidity needs and comply with covenants related to our Exit Credit Facility and other existing financing obligations; (vi) our ability to complete the implementation of our Plan of Reorganization and the discharge of our Chapter 11 cases including successfully resolving any remaining claims; (vii) disruptions in or limitations on the transportation of natural gas and transmission of electricity; (viii) the expiration or termination of our PPAs and the related results on revenues; (ix) risks associated with the operation of power plants including unscheduled outages; (x) factors that impact the output of our geothermal resources and generation facilities, including unusual or unexpected steam field well and pipeline maintenance and variables associated with the waste water injection projects that supply added water to the steam reservoir; (xi) risks associated with power project development and construction activities; (xii) our ability to attract, retain and motivate key employees including filling certain significant positions within our management team; (xiii) our ability to attract and retain customers and counterparties; (xiv) competition; (xv) risks associated with marketing and selling power from plants in the evolving energy markets; (xvi) present and possible future claims, litigation and enforcement actions; (xvii) effects of the application of laws or regulations, including changes in laws or regulations or the interpretation thereof; and (xviii) other risks identified in this Report and our 2007 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.

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 therewith, 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, TX 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.

Executive Overview

We are an independent power producer that operates and develops clean and reliable power generation facilities primarily in the U.S. Our fleet of power generation facilities, with nearly 24,000 MW of capacity as of June 30, 2008, makes us one of the largest independent power producers in the U.S. Our portfolio is comprised of two power generation technologies: natural gas-fired combustion (primarily combined-cycle) and renewable geothermal. We operate 60 natural gas-fired power plants capable of producing approximately 23,000 MW and 17 geothermal facilities in the Geysers region of northern California capable of producing 725 MW. Our renewable geothermal facilities are the largest producing geothermal resource in the U.S.

We are focused on maximizing the value of the Company by leveraging our portfolio of power plants, our geographic diversity and our operational and commercial expertise to provide the optimal combination of products and services to our customers. To accomplish this goal, we seek to maximize asset performance, optimize the management of our commodity exposure and take advantage of growth and development opportunities that fit our core business and are accretive to earnings.

Our Financial Performance Highlights

During the three months ended June 30, 2008, we recognized net income of $197 million compared to a net loss of $(500) million during the same period a year ago. Our current period net income primarily resulted from higher market spark spreads in our West and Texas segments and a decrease in reorganization items as a result of our emergence from Chapter 11 during the first quarter of 2008. Also contributing to our improved results in our Southeast segment was additional revenue of $21 million recognized related to a transmission capacity contract that was approved by the FERC during the three months ended June 30, 2008.

During the six months ended June 30, 2008, we recognized a net loss of $(17) million compared to a net loss of $(959) million during the same period a year ago. The reduction in our current period net loss primarily resulted from higher market spark spreads in our West and Texas segments during the three months ended June 30, 2008, and a decrease in reorganization items as a result of our emergence from Chapter 11, gain on reconsolidation of our Canadian Debtors and gains on sales of our Fremont and Hillabee assets during the first quarter of 2008. Also contributing to our improved results in our Southeast segment was additional revenue of $21 million recognized related to a transmission capacity contract that was approved by the FERC during the three months ended June 30, 2008.

NRG Proposal

On May 14, 2008, we received an unsolicited proposal from NRG regarding a potential combination between the Company and NRG. The terms of NRG's proposal included an all-stock merger transaction at a fixed exchange ratio of 0.534x. On May 30, 2008, we announced that our Board of Directors had determined that NRG's proposal was inadequate and materially undervalued our unique asset portfolio and future prospects. We and NRG, and our respective advisors, subsequently exchanged certain information in order to ascertain whether there was a basis for discussions between us and NRG to explore a business combination. Following the exchange of certain information, we determined that there was no basis for entering into discussions regarding a potential business combination with NRG.

Financial Reporting Matters Following Our Emergence from Chapter 11

During the three and six month periods ended June 30, 2007, and for the period January 1, 2008, through the Effective Date, 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. Our Plan of Reorganization provided for the discharge of claims through the issuance of reorganized Calpine Corporation common stock, cash and cash equivalents, or a combination thereof. On or about the Effective Date, we canceled all of our then outstanding common stock and authorized the issuance of 485 million shares of reorganized Calpine Corporation common stock for distribution to holders of unsecured claims and for general contingencies pursuant to our Plan of Reorganization. In addition, we issued warrants to purchase approximately 48.5 million shares of reorganized Calpine Corporation common stock to the holders of our previously outstanding common stock that had been canceled on the Effective Date. Our reorganized Calpine Corporation common stock has been listed on the NYSE and began "regular way" trading under the symbol "CPN" on February 7, 2008.

At the Petition Date, we carried $17.4 billion of debt with an average interest rate of 10.3%. As a result of retiring unsecured debt with reorganized Calpine Corporation common stock, proceeds received from the sale of certain of our assets and the repayment or refinancing of certain of our project debt, we have reduced our pre-petition debt by approximately $7.0

billion. On the Effective Date, we closed on our approximately $7.3 billion of Exit Facilities. We borrowed approximately $6.4 billion under our Exit Facilities, which was used to repay the outstanding term loan balance of $3.9 billion (excluding the unused portion under the $1.0 billion revolver) under our DIP Facility. The remaining net proceeds of approximately $2.5 billion were used to fund cash payment obligations under the Plan of Reorganization including the repayment of a portion of the Second Priority Debt and the payment of administrative claims and other pre-petition claims, as well as to pay fees and expenses in connection with the Exit Facilities and for working capital and general corporate purposes. Upon our emergence from Chapter 11, we carried $10.4 billion of debt with an average interest rate of 8.1%.

On February 8, 2008, the Canadian Effective Date, the Canadian Court ordered and declared that the proceedings under the CCAA 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 net assets include debt, 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 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 $107 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 $37 million) to $0 and recorded the $70 million balance of the excess as a gain in reorganization items on our Consolidated Condensed Statement of Operations in the first quarter of 2008.

In connection with our emergence from Chapter 11, we recorded certain “plan effect” adjustments to our Consolidated Condensed Balance Sheet as of the Effective Date in order to reflect certain provisions of our Plan of Reorganization. These adjustments included the distribution of approximately $4.1 billion in cash and the authorized issuance of 485 million shares of reorganized Calpine Corporation common stock as described above. As a result, our equity increased by approximately $8.9 billion.

During the pendency of the Chapter 11 cases, we began an asset rationalization process that resulted in the sale of certain under-performing assets and non-core businesses. We sold the assets of the Hillabee and Fremont development projects for which construction had been suspended and recorded pre-tax gains of approximately $199 million as reorganization items related to these asset sales during the first quarter of 2008. The proceeds from these two sales were used to retire the $300 million drawn under our Bridge Facility. We believe these actions will allow us to compete more effectively in the future in the markets in which we operate.

Our Business Segments

We assess our business primarily on a regional basis due to the impact on our financial performance of the differing characteristics of these regions. Our reportable segments are West (including geothermal), Texas, Southeast, North and Other. Our Other segment currently includes fuel management, our turbine maintenance group, certain hedging and other corporate activities.

Results of Operations for the Three Months Ended June 30, 2008 and 2007

Set forth below are the results of operations for the three months ended June 30, 2008, as compared to the same period in 2007 (in millions). In the comparative tables 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 in the “$ Change” and ‘‘% Change” columns.

	2008	2007	$ Change	% Change
Operating revenues	$ 2,828	$ 2,060	$ 768	37%
Cost of revenue:				
Fuel and purchased energy expense	2,008	1,456	(552)	(38)
Plant operating expense	206	211	5	2
Depreciation and amortization expense	108	118	10	8
Other cost of revenue	30	33	3	9
Total cost of revenue	2,352	1,818	(534)	(29)
Gross profit	476	242	234	97
Sales, general and other administrative expense	48	39	(9)	(23)
Other operating (income) expense	(5)	3	8	#
Income from operations	433	200	233	#
Interest expense	206	264	58	22
Interest (income)	(14)	(17)	(3)	(18)
Minority interest income	—	(3)	(3)	#
Other (income) expense, net	1	(6)	(7)	#
Income (loss) before reorganization items and income taxes	240	(38)	278	#
Reorganization items	18	469	451	96
Income (loss) before income taxes	222	(507)	729	#
Provision (benefit) for income taxes	25	(7)	(32)	#
Net income (loss)	$ 197	$ (500)	$ 697	#

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\# Variance of 100% or greater

Operating revenues increased primarily as a result of a 39% increase in our average realized electric price for the three months ended June 30, 2008, compared to the same period in 2007. As a result, our electricity and steam revenue as well as hedging and optimization revenue, both components of our operating revenues, increased by $601 million, or 41%, and $325 million, or 72%, respectively, during the three months ended June 30, 2008, compared to 2007. These increases were partially offset by mark-to-market losses on derivative electricity contracts that do not qualify for hedge accounting, which totaled $8 million for the second quarter of 2008 compared to mark-to-market gains of $147 million for the second quarter of 2007.

Fuel and purchased energy expense increased due to a 31% increase in the average cost of natural gas consumed as well as a $347 million, or 98%, increase in hedging and optimization expense for the three months ended June 30, 2008, compared to the three months ended June 30, 2007. The increase was partially offset by mark-to-market gains on derivative natural gas contracts that do not qualify for hedge accounting, which totaled $32 million for the second quarter of 2008 compared to mark-to-market losses of $94 million for the second quarter of 2007.

Plant operating expense decreased during the three months ended June 30, 2008, compared to the same period in 2007 primarily as a result of a $7 million decrease in insurance costs due to increased recoveries in the second quarter of 2008, a $3 million decrease in property taxes and a $4 million decrease in expense for major maintenance and parts repair costs. The decrease was partially offset by an $8 million increase in routine maintenance costs.

Depreciation and amortization expense decreased for the three months ended June 30, 2008, compared to the three months ended June 30, 2007, primarily related to a revision in the estimated useful life for our geothermal facilities in the Geysers region of northern California as well as the sale of Acadia PP in September 2007.

Other cost of revenue decreased for the three months ended June 30, 2008, compared to the three months ended June 30, 2007, resulting primarily from a decrease in operating lease expense due to the termination of the lease associated with our purchase of the RockGen Energy Center in January 2008.

Sales, general and other administrative expenses were higher for the three months ended June 30, 2008, compared to the same period in 2007 due to a $5 million increase in personnel costs due primarily to higher stock compensation expense arising from the grant of equity awards during the first quarter of 2008 as well as a $4 million increase in consulting expenses.

Other operating (income) expense decreased for the three months ended June 30, 2008, compared to the three months ended June 30, 2007, primarily due to a $15 million increase in income from our investment in OMEC resulting from gains on interest rate swaps entered into by OMEC. Partially offsetting the decrease was a $6 million impairment related to the discontinuation of the development of a power project recorded during the three months ended June 30, 2008.

Interest expense decreased for the three months ended June 30, 2008, compared to the three months ended June 30, 2007, due largely to lower average debt balances and lower interest rates. During the first quarter of 2008, we settled a portion of our debt through payment of cash and issuance of reorganized Calpine Corporation common stock pursuant to the Plan of Reorganization. Additionally, interest rates on our variable rate debt were lower for the three months ended June 30, 2008, compared to 2007, due to a decrease in LIBOR over the same periods. The decrease was partially offset by losses recorded on interest rate swaps related to our Exit Credit Facility during the three months ended June 30, 2008.

Other (income) expense, net increased primarily due to $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.

The table below lists the significant items within reorganization items for the three months ended June 30, 2008 and 2007 (in millions, except for percentages):

	2008	2007	$ Change	% Change
Provision for expected allowed claims	$ 5	$ 230	$ 225	98%
Professional fees	14	49	35	71
Asset impairments	—	106	106	#
Loss on reconsolidation of Canadian Debtors	5	—	(5)	—
Interest (income) on accumulated cash	—	(15)	(15)	#
Other	(6)	99	105	#
Total reorganization items	$ 18	$ 469	$ 451	96

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\# Variance of 100% or greater

Provision for Expected Allowed Claims — During the three months ended June 30, 2008, we recorded $5 million in miscellaneous charges related to Chapter 11 claims. During the three months ended June 30, 2007, our provision for expected allowed claims consisted primarily of (i) $85 million related to the settlement agreement with Cleco as a result of the rejection of two PPAs for the output of the Acadia Energy Center, (ii) an additional accrual of $81 million resulting from the rejection of certain leases and other agreements related to the Rumford and Tiverton power plants for which we agreed to allow general unsecured claims in the aggregate of $190 million and (iii) $65 million resulting from a stipulated settlement related to the RockGen facility.

Professional Fees — The decrease in professional fees for the three months ended June 30, 2008, over the comparable period in 2007 resulted primarily from a decrease in activity managed by our third party advisors related to our Chapter 11 and CCAA cases.

Asset Impairments — During the three months ended June 30, 2007, asset impairment charges consisted primarily of a pre-tax, predominately non-cash impairment charge of approximately $89 million to record our interest in Acadia PP at fair value less cost to sell.

Interest (Income) on Accumulated Cash — The decrease in interest income on accumulated cash for the three months ended June 30, 2008, over the comparable period in 2007 related to our emergence from Chapter 11 on January 31, 2008, at which time we ceased allocating a portion of interest income to reorganization items.

Other — During the three months ended June 30, 2008, other reorganization items consisted primarily of a $7 million decrease to emergence incentive cost accruals related to our emergence from Chapter 11. During the three months ended June 30, 2007, other reorganization items consisted primarily of $86 million in foreign exchange losses on LSTC denominated in a foreign currency, primarily the Canadian dollar.

Provision for Income Taxes — For the three months ended June 30, 2008, we recorded a tax provision of approximately $25 million compared to a tax benefit of $7 million for the three months ended June 30, 2007. See Note 1 of the Notes to Consolidated Condensed Financial Statements for further information.

Results of Operations for the Six Months Ended June 30, 2008 and 2007

Set forth below are the results of operations for the six months ended June 30, 2008, as compared to the same period in 2007 (in millions). In the comparative tables 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 in the “$ Change” and ‘‘% Change” columns.

	2008	2007	$ Change	% Change
Operating revenues	$ 4,779	$ 3,722	$ 1,057	28%
Cost of revenue:				
Fuel and purchased energy expense	3,613	2,727	(886)	(32)
Plant operating expense	438	379	(59)	(16)
Depreciation and amortization expense	219	236	17	7
Other cost of revenue	62	70	8	11
Total cost of revenue	4,332	3,412	(920)	(27)
Gross profit	447	310	137	44
Sales, general and other administrative expense	96	79	(17)	(22)
Other operating expense	—	12	12	#
Income from operations	351	219	132	60
Interest expense	625	564	(61)	(11)
Interest (income)	(27)	(34)	(7)	(21)
Minority interest income	—	(1)	(1)	#
Other (income) expense, net	11	(7)	(18)	#
Loss before reorganization items and income taxes	(258)	(303)	45	15
Reorganization items	(261)	574	835	#
Income (loss) before income taxes	3	(877)	880	#
Provision for income taxes	20	82	62	76
Net loss	$ (17)	$ (959)	$ 942	98

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\# Variance of 100% or greater

Operating revenues increased primarily as a result of a 29% increase in our average realized electric price for the six months ended June 30, 2008, compared to the same period in 2007. As a result, our electricity and steam revenue as well as hedging and optimization revenue, increased by $850 million, or 31%, and $467 million, or 57%, respectively during the six months ended June 30, 2008, compared to 2007. These increases were partially offset by mark-to-market losses on derivative electricity contracts that do not qualify for hedge accounting, which totaled $104 million for the six months ended June 30, 2008, compared to mark-to-market gains of $135 million for the six months ended June 30, 2007.

Fuel and purchased energy expense increased due to a 25% increase in the average cost of natural gas consumed as well as a $489 million, or 72%, increase in hedging and optimization expense for the six months ended June 30, 2008, compared to the six months ended June 30, 2007. The increase was partially offset by an 84% decrease in mark-to-market losses on derivative natural gas contracts that do not qualify for hedge accounting, for the six months ended June 30, 2008, compared to the six months ended June 30, 2007.

Plant operating expense increased during the six months ended June 30, 2008, compared to the same period in 2007 primarily as a result of a $22 million increase in expense for major maintenance and parts repair costs and a $21 million increase in expense for outages caused by equipment failures. Also contributing to the increase were higher property taxes of $7 million and an increase of $9 million in plant personnel costs.

Depreciation and amortization expense decreased for the six months ended June 30, 2008, compared to the six months ended June 30, 2007, primarily related to a revision in the estimated useful life for our geothermal facilities in the Geysers region of northern California as well as the sale of Acadia PP in September 2007.

Other cost of revenue decreased for the six months ended June 30, 2008, compared to the six months ended June 30, 2007, resulting primarily from the sale of PSM in March 2007.

Sales, general and other administrative expenses were higher for the six months ended June 30, 2008, compared to the same period in 2007 due primarily to an $11 million increase in personnel costs due primarily to higher stock compensation expense arising from the grant of equity awards during the first half of 2008 as well as a $4 million increase in consulting expenses.

Other operating expense decreased for the six months ended June 30, 2008, compared to the six months ended June 30, 2007, primarily due to a $15 million increase in income from our investment in OMEC resulting from gains on interest rate swaps entered into by OMEC. Partially offsetting the decrease was a $4 million increase in project impairment expense during the three months ended June 30, 2008, compared to 2007, related to the discontinuation of the development of a power project.

Interest expense increased for the six months ended June 30, 2008, compared to the six months ended June 30, 2007, due largely to $148 million in non-recurring post-petition interest related to pre-petition obligations recorded during the first quarter of 2008. Also contributing to the increase was higher interest expense related to interest rate swaps that did not qualify for hedge accounting and an increase in our related party interest expense on settlement obligations related to our Canadian subsidiaries recorded prior to their reconsolidation in February 2008. The increase was partially offset by lower average debt balances and lower interest rates. During the first quarter of 2008, we settled a portion of our debt through payment of cash and issuance of reorganized Calpine Corporation common stock pursuant to the Plan of Reorganization. Additionally, we repaid our $300 million Bridge Facility with the proceeds received from the sales of the Hillabee and Fremont development project assets. We lowered our effective interest rates on existing debt compared to the same period in 2007 through the refinancings of the CalGen Secured Debt in late March 2007 with proceeds received under the DIP Facility, which carried lower interest rates.

Interest income decreased primarily due to lower average cash balances for the six months ended June 30, 2008, compared to the same period in 2007 resulting from the distribution of cash pursuant to the Plan of Reorganization in the first quarter of 2008, and due to lower average interest rates.

Other (income) expense, net decreased primarily due to $7 million in refinancing costs related to the refinancing of all outstanding indebtedness under the existing Blue Spruce term loan facility in February 2008 and $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.

The table below lists the significant items within reorganization items for the six months ended June 30, 2008 and 2007 (in millions, except for percentages):

	2008	2007	$ Change	% Change
Provision for expected allowed claims	$ (54)	$ 335	$ 389	#%
Professional fees	76	95	19	20
Gains on asset sales, net of equipment impairments	(203)	(250)	(47)	(19)
Asset impairments	—	120	120	#
Gain on reconsolidation of Canadian Debtors	(65)	—	65	—
DIP Facility financing and CalGen Secured Debt repayment costs	(4)	160	164	#
Interest (income) on accumulated cash	(7)	(23)	(16)	(70)
Other	(4)	137	141	#
Total reorganization items	$ (261)	$ 574	$ 835	#

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\# Variance of 100% or greater

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. During the six months ended June 30, 2007, our provision for expected allowed claims consisted primarily of (i) $112 million resulting from the repudiation of a gas transportation contract, (ii) $85 million related to the settlement agreement with Cleco as a result of the rejection of two PPAs for the output of the Acadia Energy Center, (iii) an additional accrual of $81 million resulting from the rejection of certain leases and other agreements related to the Rumford and Tiverton power plants for which we agreed to allow general unsecured claims in the aggregate of $190 million and (iv) $65 million resulting from a stipulated settlement related to the RockGen facility.

Professional Fees — The decrease in professional fees for the six months ended June 30, 2008, over the comparable period in 2007 resulted primarily from a decrease in activity managed by our third party advisors related to our Chapter 11 and CCAA cases.

Gains on Asset Sales, Net of Equipment Impairments — During the six months ended June 30, 2008, gains on asset sales primarily resulted from the sales of the Hillabee and Fremont development project assets. See Note 5 of the Notes to Consolidated Condensed Financial Statements for further information. During the six months ended June 30, 2007, gains on asset sales primarily resulted from the sales of MEP Pleasant Hill, LLC (consisting primarily of the Aries Power Plant), Goldendale Energy Center and PSM.

Asset Impairments — During the six months ended June 30, 2007, asset impairment charges consisted primarily of a pre-tax, predominately non-cash impairment charge of approximately $89 million to record our interest in Acadia PP at fair value less cost to sell.

Gain on Reconsolidation of Canadian Debtors — During the first quarter of 2008, we recorded a gain of $70 million related to the reconsolidation of our Canadian subsidiaries. The gain was reduced by $5 million during the three months ended June 30, 2008, due to the write-off of a receivable deemed uncollectible and recording additional Canadian withholding taxes. See Note 1 of the Notes to Consolidated Condensed Financial Statements for further information.

DIP Facility Financing and CalGen Secured Debt Repayment Costs — During the six months ended June 30, 2008, we recorded a $4 million credit related to a valuation revision for secured shortfall claims related to our Second Priority Debt. During the six months ended June 30, 2007, we recorded costs related to the refinancing of our Original DIP Facility and repayment of the CalGen Secured Debt consisting of (i) $52 million of DIP Facility transaction costs, (ii) the write-off of $32 million in unamortized discount and deferred financing costs related to the CalGen Secured Debt and (iii) $76 million as our estimate of the expected allowed claims resulting from the unsecured claims for damages granted to the holders of the CalGen Secured Debt.

Interest (Income) on Accumulated Cash — The decrease in interest income on accumulated cash for the six months ended June 30, 2008, over the comparable period in 2007 related to our emergence from Chapter 11 at which time we ceased allocating a portion of interest income to reorganization items.

Other — Other reorganization items decreased primarily due to a $96 million decrease in foreign exchange losses on LSTC denominated in a foreign currency, primarily the Canadian dollar, during the six months ended June 30, 2008, compared to 2007 as well as a non-recurring charge of $14 million in the first quarter of 2007, resulting from debt pre-payment and make whole premium fees to the project lenders related to the sale of the Aries Power Plant. Also contributing to the decrease was a $23 million decrease in emergence incentive cost accruals related to our emergence from Chapter 11 recorded during the six months ended June 30, 2008, compared to the six months ended June 30, 2007.

Provision for Income Taxes — For the six months ended June 30, 2008, we recorded a tax provision of approximately $20 million compared to a tax provision of $82 million for the six months ended June 30, 2007. See Note 1 of the Notes to Consolidated Condensed Financial Statements for further information.

Non-GAAP Financial Measures

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 utilize as a measure of our liquidity and performance. Generally, a non-GAAP financial measure is a numerical measure of financial performance, financial position or cash flows that exclude (or include) amounts that are included in (or excluded from) the most directly comparable measure calculated and presented in accordance with GAAP.

Consolidated Commodity Margin

We use the non-GAAP financial measure “commodity margin” to assess our financial performance on a consolidated basis and by our reportable segments. Commodity margin includes our electricity and steam revenues, hedging and optimization activities, renewable energy credit revenue, transmission revenue and expenses, and fuel and purchased energy expense, but excludes net commodity mark-to-market activity and other service revenues. 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 purport 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.

The following table reconciles our commodity margin to our GAAP results for the three months ended June 30, 2008 and 2007 (in millions):

	2008	2007
Operating revenues	$ 2,828	$ 2,060
(Less): Other service revenues	(11)	(16)
(Less): Fuel and purchased energy expense	(2,008)	(1,456)
Adjustment to remove: Mark-to-market commodity activity, net[1]	(24)	(53)
Consolidated commodity margin	$ 785	$ 535

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(1) Included in operating revenues and fuel and purchased energy expense.

Our consolidated commodity margin increased by $250 million, or 47%, for the three months ended June 30, 2008, compared to the three months ended June 30, 2007. The increase is primarily due to higher market spark spreads, particularly in Texas. Generation was relatively unchanged, even though our average total MW in operation decreased by 8% for the three months ended June 30, 2008, compared to 2007. Our average capacity factor, excluding peakers, increased to 46.4% for the three months ended June 30, 2008, compared to 43.3% for the three months ended June 30, 2007. See "— Operating Performance Metrics" below for a definition of average capacity factor.

Commodity Margin by Segment

The following table shows our commodity margin by segment for the three months ended June 30, 2008 and 2007 (in millions, except for percentages):

	2008	2007	$ Change	% Change
West	$ 340	$ 265	$ 75	28%
Texas	258	138	120	87
Southeast	91	65	26	40
North	72	75	(3)	(4)
Other	24	(8)	32	#
Consolidated commodity margin	$ 785	$ 535	$ 250	47

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\# Variance of 100% or greater

West — Commodity margin in our West segment increased by 28% for the three months ended June 30, 2008, compared to the same period in the prior year due in part to higher off-peak spark spreads in April 2008, the impact of new power contracts, and, to a lesser extent, a 2% increase in generation during the three months ended June 30, 2008, compared to 2007. Our average capacity factor, excluding peakers, and our average availability increased marginally, both by 4%, for the three months ended June 30, 2008, compared to the three months ended June 30, 2007.

Texas — Commodity margin in our Texas segment increased by 87% due primarily to higher market spark spreads resulting from transmission congestion and warmer temperatures in the second quarter of 2008, as compared to the same period in 2007. Generation in our Texas segment increased by 19%, and we experienced a 19% increase in our average capacity factor to 59.8% for the three months ended June 30, 2008, from 50.1% for the three months ended June 30, 2007.

Southeast — Commodity margin in our Southeast segment increased by 40% resulting from the impact of new power contracts in the second quarter of 2008, as compared to the same period in 2007. Also contributing to the increase was $21 million of commodity margin recognized during the second quarter of 2008 related to a transmission capacity contract for which we received FERC approval during the three months ended June 30, 2008. The increase in commodity margin in our Southeast segment was partially offset by a 35% decrease in generation for the three months ended

June 30, 2008, compared to the three months ended June 30, 2007, due in part to a 17% decrease in our average total MW in operation from the sale of our interest in Acadia PP in 2007.

North — Commodity margin in our North segment decreased by 4% resulting from a 29% decrease in generation for the three months ended June 30, 2008, compared to the same period in 2007 due to the deconsolidation of RockGen in the first quarter of 2008 and outages at our Westbrook Power Plant during the second quarter of 2008. The effects of these decreases were largely offset by higher realized spark spreads in the second quarter of 2008 compared to 2007.

Other — Commodity margin in our Other segment increased by $32 million primarily resulting from the favorable impact of our commodity trading activity that is not region specific.

The following table reconciles our commodity margin to our GAAP results for the six months ended June 30, 2008 and 2007 (in millions):

	2008	2007
Operating revenues	$ 4,779	$ 3,722
(Less): Other service revenues	(22)	(44)
(Less): Fuel and purchased energy expense	(3,613)	(2,727)
Adjustment to remove: Mark-to-market commodity activity, net(1)	127	6
Consolidated commodity margin	$ 1,271	$ 957

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(1) Included in operating revenues and fuel and purchased energy expense.

Our consolidated commodity margin increased by $314 million, or 33%, for the six months ended June 30, 2008, compared to the six months ended June 30, 2007. The increase is primarily due to higher market spark spreads, particularly in Texas. Generation was relatively unchanged, even though our average total MW in operation decreased by 8% for the six months ended June 30, 2008, compared to 2007. Our average capacity factor, excluding peakers, increased to 46.3% for the six months ended June 30, 2008, compared to 42.5% for the six months ended June 30, 2007. See "— Operating Performance Metrics" below for a definition of average capacity factor.

Commodity Margin by Segment

The following table shows our commodity margin by segment for the six months ended June 30, 2008 and 2007 (in millions, except for percentages):

	2008	2007	$ Change	% Change
West	$ 609	$ 495	$ 114	23%
Texas	388	224	164	73
Southeast	128	102	26	25
North	134	138	(4)	(3)
Other	12	(2)	14	#
Consolidated commodity margin	$ 1,271	$ 957	$ 314	33

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\# Variance of 100% or greater

West — Commodity margin in our West segment increased by 23% for the six months ended June 30, 2008, compared to the same period a year ago due to higher off-peak spark spreads in April 2008, the impact of new power contracts, and a 6% increase in generation during the six months ended June 30, 2008, compared to 2007. Our average capacity factor, excluding peakers, increased by 8% for the six months ended June 30, 2008, compared to the six months ended June 30, 2007.

Texas — Commodity margin in our Texas segment increased by 73% due primarily to higher market spark spreads resulting from transmission congestion and warmer temperatures for the six months ended June 30, 2008, as compared to the same period in 2007. Generation in our Texas segment increased by 9%, and we experienced a 9% increase in our average capacity factor to 54.4% for the six months ended June 30, 2008, from 49.8% for the six months ended June 30, 2007.

Southeast — Commodity margin in our Southeast segment increased by 25% resulting from the impact of new power contracts during the six months ended June 30, 2008, as compared to the same period in 2007. Also contributing to the increase was $21 million of commodity margin recognized during the second quarter of 2008 related to a transmission capacity contract for which we received FERC approval during the three months ended June 30, 2008.The increase in commodity margin in our Southeast segment was partially offset by a 21% decrease in generation for the six months ended June 30, 2008, compared to the six months ended June 30, 2007, due primarily to an 18% decrease in our average total MW in operation from the sale of our interest in Acadia PP in 2007.

North — Commodity margin in our North segment decreased by 3% resulting from a 20% decrease in generation for the six months ended June 30, 2008, compared to the same period in 2007 due to the deconsolidation of RockGen in the first quarter of 2008 and outages at our Westbrook Power Plant during the second quarter of 2008. The effects of these decreases were largely offset by higher realized spark spreads during the six months ended June 30, 2008, compared to 2007.

Other — Commodity margin in our Other segment increased by $14 million primarily resulting from the favorable impact of our commodity trading activity that is not region specific.

Adjusted EBITDA

We define Adjusted EBITDA as EBITDA as 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. Adjusted EBITDA does not purport to represent cash flow 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 used by and useful to investors and other users of our financial statements in analyzing our liquidity as it is the basis for material covenants under the Exit Credit Facility. Substantially similar covenants are also included in certain of our other debt instruments, including the Commodity Collateral Revolver. We are not permitted to exceed a consolidated leverage ratio calculated by dividing total net debt by Adjusted EBITDA (defined as “Consolidated EBITDA” in the Exit Credit Facility), and we must also comply with (i) a minimum ratio of Adjusted EBITDA to cash interest expense and (ii) a maximum ratio of total senior net debt to Adjusted EBITDA. Moreover, prior to the conversion of the loans and commitments under the DIP Facility to our exit financing under the Exit Credit Facility on the Effective Date, Adjusted EBITDA formed the basis for material covenants under our DIP Facility, which was our primary source of financing during our Chapter 11 cases. Non-compliance with these covenants could result in the lenders under the Exit Credit Facility requiring us to immediately repay all amounts borrowed and could allow the lenders under the Commodity Collateral Revolver to take similar actions. In addition, if we cannot satisfy these financial covenants, we may be prohibited from engaging in other activities, such as incurring additional indebtedness and making restricted payments.

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 excludes the impact of reorganization items and impairment charges, among other items as detailed in the below reconciliation. We have recognized substantial reorganization items, both direct and incremental, in connection with our Chapter 11 cases as well as substantial asset impairment charges related to our Chapter 11 filings and actions we have taken with respect to our portfolio of assets in connection with our reorganization efforts. These reorganization items and impairment charges are not expected to continue at these levels following our emergence from Chapter 11, but rather are expected to be reduced significantly over time in the periods following our emergence. Therefore, we exclude reorganization items and impairment charges 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 (i) as a measure of liquidity in determining our ability to maintain borrowings under certain of our credit facilities, primarily the Exit Credit Facility; (ii) 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; (iii) as a measure for planning and forecasting overall expectations and for evaluating actual results against such expectations; and (iv) in communications with our Board of Directors, shareholders, creditors, analysts and investors concerning our financial performance.

The below table provides a reconciliation of Adjusted EBITDA to our cash flow from operations and GAAP net income (loss) (in millions):

	Three Months Ended June 30, 2008	Three Months Ended June 30, 2007	Six Months Ended June 30, 2008	Six Months Ended June 30, 2007
Cash provided by (used in) operating activities	$ (324)	$ 48	$ (586)	$ (184)
Less:				
Changes in operating assets and liabilities, excluding the effects of acquisition	(306)	51	(432)	(78)
Additional adjustments to reconcile GAAP net income (loss) to net cash provided by (used in) operating activities:				
Depreciation and amortization[1]	125	141	280	284
Deferred income taxes, net	21	(7)	85	82
Change in derivatives and derivative contracts classified as financing activities	(362)	(73)	(192)	(10)
Reorganization items	3	434	(322)	497
Other	(2)	2	12	—
GAAP net income (loss)	197	(500)	(17)	(959)
Add:				
Adjustments to reconcile Adjusted EBITDA to net income (loss):				
Interest expense, net of interest income	192	247	598	530
Depreciation and amortization expense, excluding deferred financing costs[1]	118	129	240	258
Provision (benefit) for income taxes	25	(7)	20	82
Impairment charges	6	—	6	2
Reorganization items	18	469	(261)	574
Major maintenance expense	42	46	96	74
Losses on repurchase or extinguishment of debt	6	—	13	—
Operating lease expense	11	13	23	24
(Gains) losses on derivatives (non-cash portion)	(151)	(65)	28	(2)
Other	10	(6)	22	(7)
Adjusted EBITDA	$ 474	$ 326	$ 768	$ 576

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

Operating Performance Metrics

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

- *Total MWh generated.* We generate power that we sell to third parties. The volume in MWh is a direct indicator of our level of electricity generation activity.

- *Average availability and average capacity factor, excluding peakers.* Availability represents the percent of total hours during the period that our plants were available to run after taking into account the downtime associated with both scheduled and unscheduled outages. The average capacity factor, excluding peakers is calculated by dividing (a) total MWh generated by our power plants (excluding peakers) by the product of multiplying (b) the weighted average MW in operation during the period by (c) the total hours in the period. The average capacity factor, excluding peakers is thus a measure of total actual generation as a percent of total potential generation. If we elect not to generate during periods when electricity pricing is too low or gas prices too high to operate profitably, the average capacity factor, excluding peakers will reflect that decision as well as both scheduled and unscheduled outages due to maintenance and repair requirements.

- *Steam adjusted Heat Rate for gas-fired fleet of power plants expressed in Btus of fuel consumed per KWh generated.* We calculate the steam adjusted Heat Rate for our gas-fired power plants (excluding peakers) by dividing (a) fuel consumed in Btu by (b) KWh generated. We adjust the fuel consumption in Btu down by the equivalent heat content in steam or other thermal energy exported to a third party, such as to steam hosts for our cogeneration facilities. The resultant steam adjusted Heat Rate is a measure of fuel efficiency, so the lower the steam adjusted Heat Rate, the lower our cost of generation.

- *Average realized electric price expressed in dollars per MWh generated.* Our energy trading and optimization activities are integral to our power generation business and directly impact our total realized revenues from generation. Accordingly, we calculate the average realized electric price per MWh generated by dividing (a) adjusted electricity and steam revenue, which includes capacity revenues, energy revenues, thermal revenues, the spread on sales of purchased electricity for hedging, balancing, and optimization activity by (b) total generated MWh in the period.

- *Average cost of natural gas expressed in dollars per MMBtu of fuel consumed.* Our energy trading and optimization activities related to fuel procurement directly impact our total fuel and purchased energy expense. The fuel costs for our gas-fired power plants are a function of the price we pay for fuel purchased and the results of the fuel hedging, balancing, and optimization activities by CES. Accordingly, we calculate the cost of natural gas per MMBtu of fuel consumed in our power plants by dividing (a) adjusted fuel expense which includes the cost of fuel consumed by our plants and the spread on sales of purchased gas for hedging, balancing, and optimization activity, by (b) the heat content in millions of Btu of the fuel we consumed in our power plants for the period.

The table below shows the operating performance metrics for continuing operations discussed above:

	Three Months Ended June 30,		Six Months Ended June 30,	
	2008(1)	2007(1)	2008(1)	2007(1)
	(MWh in thousands)			
Total MWh generated	21,211	21,439	42,117	41,782
West	7,982	7,824	17,139	16,243
Texas	9,477	7,962	17,218	15,733
Southeast	2,635	4,084	5,305	6,745
North	1,117	1,569	2,455	3,061
Average Availability	89.9%	89.9%	87.9%	90.3%
West	89.6%	86.2%	86.5%	88.0%
Texas	91.8%	88.0%	86.9%	89.3%
Southeast	89.3%	95.5%	90.2%	94.5%
North	87.4%	90.8%	89.7%	88.5%
Average total MW in operation	23,113	25,091	23,113	25,223
West	7,246	7,246	7,246	7,317
Texas	7,251	7,274	7,251	7,274
Southeast	6,254	7,556	6,254	7,615
North	2,362	3,015	2,362	3,017
Average MW of peaker facilities	2,540	3,019	2,540	3,010
West	983	983	983	972
Texas	—	—	—	—
Southeast	963	963	963	963
North	594	1,073	594	1,075
Average capacity factor, excluding peakers	46.4%	43.3%	46.3%	42.5%
West	57.3%	55.1%	61.9%	57.5%
Texas	59.8%	50.1%	54.4%	49.8%
Southeast	21.2%	26.8%	21.9%	22.4%
North	28.0%	35.4%	31.1%	35.0%
Steam adjusted Heat Rate	7,268	7,182	7,215	7,147
West	7,319	7,366	7,269	7,342
Texas	7,144	6,780	7,057	6,733
Southeast	7,459	7,462	7,460	7,492
North	7,635	7,857	7,516	7,753
Average realized electric price	$ 99.58	$ 71.42	$ 87.42	$ 67.71
Average cost of natural gas per MMBtu	$ 8.74	$ 6.67	$ 8.14	$ 6.52

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(1) Excludes plants which have been deconsolidated, sold, are not operated by us or are no longer in operation as of the date deconsolidated or sold. See Note 1 and Note 5 of the Notes to Consolidated Condensed Financial Statements.

Liquidity and Capital Resources

Our business is capital intensive. Our ability to successfully implement our business plan, including operating our current fleet of power plants, completing our remaining plants under construction and maintaining our relationships with vendors, suppliers, customers and others with whom we conduct or seek to conduct business, as well as exploring potential growth opportunities, is dependent on the continued availability of capital on attractive terms. As described below, upon implementation of our Plan of Reorganization and emergence from Chapter 11, we converted our existing DIP Facility into exit financing under our Exit Credit Facility, which, including the term loans funded, currently provides approximately $7.0 billion of term and revolving credit.

We currently obtain cash from our operations, borrowings under credit facilities including the Exit Credit Facility, project financings and refinancings. In the past, we have also obtained cash from issuances of equity or debt securities, proceeds from sale/leaseback transactions, contract monetizations, and sale or partial sale of certain assets. We or our subsidiaries may in the future complete similar transactions consistent with achieving the objectives of our business plan. We utilize this cash to fund our operations, service or prepay debt obligations, fund acquisitions, develop and construct power generation facilities, finance capital expenditures, support our hedging, balancing and optimization activities, and meet our other cash and liquidity needs. We reinvest any cash from operations into our business or use it to reduce or pay interest on our debt, rather than to pay cash dividends. We have remaining unused credit under our Exit Credit Facility of approximately $221 million to issue additional letters of credit or to borrow additional cash. We recently entered into two credit facilities that increase our liquidity available to collateralize obligations to counterparties under eligible commodity hedge agreements during periods of increasing gas prices. We entered into the twelve month Knock-in Facility on June 25, 2008, which provides an initial $50 million of available capacity for the issuance of letters of credit up to a total maximum availability of $200 million contingent on natural gas futures contract prices exceeding certain thresholds and the Commodity Collateral Revolver on July 8, 2008, with an initial advance of $100 million and up to a total maximum availability of $300 million contingent on mark-to-market exposure amounts under certain reference transactions.

We have significant NOLs that will provide future tax deductions if we generate sufficient taxable income during the carryover periods. We have recorded a valuation allowance against most of these losses as we determined it is more likely than not they will not be realized as measured under GAAP. Approximately $5.1 billion of our NOLs have annual limitations under IRC Section 382. Amounts subject to limitations, but not used, can be carried forward to succeeding years. We also expect to generate approximately $1.5 billion to $2.0 billion in NOLs in 2008. Approximately 90% of this NOL will not be subject to annual limitation under IRC Section 382 unless we experience another ownership change before it is utilized. In addition, we have approximately $900 million in NOLs related to Canada with a full valuation allowance.

We do not intend to pay any cash dividends on our common stock in the foreseeable future because of our ongoing liquidity constraints and the needs of our business operations. In addition, our ability to pay cash dividends is restricted under the Exit Credit Facility and certain of our other debt agreements. Future cash dividends, if any, will be at the discretion of our Board of Directors and will depend upon, among other things, our future operations and earnings, capital requirements, general financial condition, contractual restrictions and such other factors as our Board of Directors may deem relevant.

In order to improve our liquidity position, maximize our core strategic assets in the markets in which we operate and control our business growth, we began taking steps during and after our emergence from Chapter 11 to stabilize, improve and strengthen our power generation business and our financial health by reducing activities and curtailing expenditures in certain non-core areas. We expect to continue our efforts to reduce overhead and discontinue activities that do not have compelling profit potential or otherwise do not constitute a strategic fit with our core business of generating and selling electricity and electricity-related products. Our development activities were reduced, and we have only one project, Russell City Energy Center, currently in active development. As of the filing of this Report, we have been successful in obtaining an agreement in principle to amend the PPA between PG&E and Russell City Energy Center which provides for continued development of the project and extends the expected commercial operation date by two years from 2010 to June 2012. On July 29, 2008, the EAB remanded the PSD permit to the Bay Area Air Quality Management District for the Russell City Energy Center. The PSD permit was remanded solely based on the finding that the District failed to issue timely notice of the public comment period on the PSD permit. The Bay Area Air Quality Management District is directed to reopen the public comment period on the draft PSD permit, providing public notice fully consistent with the federal noticing requirements. The EAB found no substantive defects in the Permit, and also addressed and denied review of each substantive claim in the Appeal on the basis that they fell beyond the EAB’s jurisdiction and added that it would not subsequently consider these claims. If the PSD permit is not appealed again, it is expected to be final by the end of November 2008. We have interests in two projects, OMEC and Greenfield LP, currently under construction. We continue to review other development opportunities, which were put on hold during the pendency of our Chapter 11 cases, to determine whether future actions are appropriate. We may also pursue new opportunities that arise, including expansions of existing facilities, particularly if power contracts and financing are available and attractive returns are expected. We have completed the sale of certain of our power plants or other assets, and expect that, as a result of our ongoing review process, additional power plants or other assets may be sold, the agreements relating to certain of our facilities may be restructured, or commercial operations may be suspended at certain of our power plants. See Note 5 of the Notes to Consolidated Condensed Financial Statements and "— Asset Sales and Purchase of Investment" below for further information regarding activities during the six months ended June 30, 2008.

We believe the actions we have taken, including implementing our Plan of Reorganization, closing on our Exit Credit Facility, Commodity Collateral Revolver and Knock-in Facility, reducing our activities in certain non-core areas and disposing of certain underperforming assets, will allow us to generate sufficient cash to support our operations over the next twelve months and beyond. Our ability to generate sufficient cash is dependent upon, among other things: (i) improving the profitability of our operations; (ii) complying with the covenants under our Exit Credit Facility and other existing financing obligations; (iii) developing a long-term strategy focused on projects that fit our core business; and (iv) stabilizing and increasing future contractual cash flows.

Exit Facilities — Upon our emergence from Chapter 11, we converted the approximately $4.9 billion of loans and commitments outstanding under our DIP Facility (including the $1.0 billion revolver) into loans and commitments under our approximately $7.3 billion of Exit Facilities. The Exit Facilities provide for approximately $2.1 billion in senior secured term loans and $300 million in senior secured bridge loans in addition to the loans and commitments that had been available under the DIP Facility. The Exit Facilities include:

- The Exit Credit Facility, comprising (i) approximately $6.0 billion of senior secured term loans; (ii) a $1.0 billion senior secured revolving facility; and (iii) the ability 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; and

- The Bridge Facility, which, prior to its repayment as described below, provided for a $300 million senior secured bridge term loan.

The approximately $6.0 billion of senior secured term loans and the $300 million Bridge Facility were fully drawn and we drew approximately $150 million under the $1.0 billion senior secured revolving facility on the Effective Date. The proceeds of the drawdowns, above the amounts that had been applied under the DIP Facility as described below, were used to repay a portion of the Second Priority Debt, fund distributions under the Plan of Reorganization to holders of other secured claims and to pay fees, costs, commissions and expenses in connection with the Exit Facilities and the implementation of our Plan of Reorganization. Term loan borrowings under the Exit Credit Facility bear interest at a floating rate of, at our option, 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, with the remaining unpaid amount due and payable at maturity on March 29, 2014.

As of March 6, 2008, the Bridge Facility had been repaid in full in accordance with its terms with proceeds from the sales of the Hillabee and Fremont development project assets.

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 covenant restrictions, including limiting our ability to, among other things: (i) incur additional indebtedness and issue stock; (ii) make prepayments on or purchase indebtedness in whole or in part; (iii) pay dividends and other distributions with respect to our stock or repurchase our stock or make other restricted payments; (iv) use money borrowed under the Exit Credit Facility for non-guarantors (including foreign subsidiaries); (v) make certain investments; (vi) create or incur liens to secure debt; (vii) consolidate or merge with another entity, or allow one of our subsidiaries to do so; (viii) lease, transfer or sell assets and use proceeds of permitted asset leases, transfers or sales; (ix) limit dividends or other distributions from certain subsidiaries up to Calpine; (x) make capital expenditures beyond specified limits; (xi) engage in certain business activities; and (xii) acquire facilities or other businesses.

The Exit Credit Facility also requires compliance with financial covenants that include (i) a maximum ratio of total net debt to Consolidated EBITDA (as defined in the Exit Credit Facility), (ii) a minimum ratio of Consolidated EBITDA to cash interest expense and (iii) a maximum ratio of total senior net debt to Consolidated EBITDA. We were in compliance with all our covenants related to our Exit Credit Facility at June 30, 2008.

As of June 30, 2008, under the Exit Credit Facility we had approximately $6.0 billion outstanding under the term loan facilities, and $525 million outstanding under the revolving credit facility and $254 million of letters of credit issued against the revolving credit facility.

Other Financing Activities — On February 1, 2008, Blue Spruce entered into a $90 million senior term loan. Net proceeds from the senior term loan were used to refinance all outstanding indebtedness under the existing Blue Spruce term loan facility, to pay fees and expenses related to the transaction and for general corporate purposes. The senior term loan carries interest at LIBOR plus an initial base rate of 1.63%, which escalates to 2.50% over the life of the senior term loan and matures December 31, 2017. The senior term loan is secured by the assets of Blue Spruce. In connection with this refinancing, we recorded $7 million in loss on debt extinguishment, related to the write-off of deferred financing costs of $4 million and breakage costs of $3 million, which are recorded in other (income) expense, net on our Consolidated Condensed Statements of Operations.

During the first quarter of 2008, we entered into a letter of credit facility related to our subsidiary Calpine Development Holdings, Inc. under which up to $150 million is available for letters of credit. As of June 30, 2008, $115 million in letters of credit had been issued under this facility.

On June 10, 2008, Metcalf closed on a $265 million new term loan facility. The proceeds were used to repay Metcalf's existing $100 million term loan facility and $155 million preferred interests. The new term loan facility, which matures on June 10, 2015, bears interest at Metcalf's option at LIBOR plus 3.25% or base rate plus 2.25% and is secured by the assets of Metcalf and the sole member interest held by Metcalf's parent, Metcalf Holdings, LLC. In connection with this refinancing, we recorded $6 million in loss on debt extinguishment, related to the write-off of deferred financing costs of $3 million and breakage costs of $3 million, which are recorded in other (income) expense, net on our Consolidated Condensed Statements of Operations.

On June 25, 2008, we entered into the Knock-in Facility, a 12-month, $200 million letter of credit facility. Our obligations under the Knock-in Facility are unsecured. Availability of letters of credit for issuance under the Knock-in Facility is up to a total maximum availability of $200 million contingent on natural gas futures contract prices exceeding certain thresholds, with initial availability for up to $50 million. As of June 30, 2008, no letters of credit had been issued under this facility.

On July 8, 2008, we entered into the Commodity Collateral Revolver, a two-year, $300 million secured revolving credit facility, which shares the benefits of the collateral subject to the liens under the Exit Credit Facility ratably with the lenders under the Exit Credit Facility. At closing, we borrowed an initial advance of $100 million. Future advances under the Commodity Collateral Revolver are limited to the lesser of $300 million and the MTM Exposure (as defined in the Commodity Collateral Revolver) under certain reference transactions, less the advanced amount then outstanding. Amounts borrowed under the Commodity Collateral Revolver are to be used to collateralize obligations to counterparties under eligible commodity hedge agreements. The Commodity Collateral Revolver bears interest at LIBOR plus 2.875% per annum. Advances may be repaid prior to the maturity date, in whole or in part, provided that partial payment shall not reduce the aggregate outstanding advances to less than $100 million. Repayments made prior to the maturity date that do not reduce the total available commitment amount are subject to a 5% premium (plus breakage costs, if any).

Both the Knock-in Facility and Commodity Collateral Revolver contain covenant restrictions and require compliance with financial covenants substantially equivalent to those under the Exit Credit Facility.

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.

During the pendency of our Chapter 11 cases, in lieu of distributions, our U.S. Debtor subsidiaries were permitted under the terms of the Cash Collateral Order to make transfers from their excess cash flow in the form of loans to other U.S. Debtors, notwithstanding the existence of any default or event of default related to our Chapter 11 cases.

Cash Flow Activities — The following table summarizes our cash flow activities for the six months ended June 30, 2008 and 2007 (in millions):

	2008	2007
Beginning cash and cash equivalents	$ 1,915	$ 1,077
Net cash provided by (used in):		
Operating activities	(586)	(184)
Investing activities	469	343
Financing activities	(1,428)	168
Net increase (decrease) in cash and cash equivalents	(1,545)	327
Ending cash and cash equivalents	$ 370	$ 1,404

Cash flows used in operating activities for the six months ended June 30, 2008, resulted in net outflows of $586 million as compared to net outflows of $184 million for the same period in 2007. The increase in net outflows compared to the same period in 2007 is primarily attributable to non-cash operating items and changes in operating assets and liabilities. For the six months ended June 30, 2008, non-cash operating items included net adjustments of $(137) million, primarily related to changes in derivatives and derivative contracts classified as fiinancing activities of $(192) million and reorganization items of $(322) from gains on sales of assets and the reconsolidation of our Canadian Debtors, partially offset by depreciation and amortization and deferred income taxes of $280 million and $85 million, respectively, as compared to net adjustments of $853 million for the same period a year ago, related to reorganization items of $497 million and depreciation and amortization and deferred income taxes of $284 million and $82 million, respectively. Other non-cash operating items remained relatively comparable from period to period. Our changes in operating assets and liabilities accounted for a net use of funds of $432 million in the six months ended June 30, 2008, compared to a net use of funds of $78 million in the same period in 2007, primarily due to $356 million in additional margin deposits and prepayments made after December 31, 2007, due to higher gas prices and corresponding increased collateral requirements.

Cash flows provided from investing activities were primarily obtained from sales of investments, turbines and power plant assets for the six months ended June 30, 2008 and the same period in 2007. Our proceeds from the sales of these assets remained the same for both periods at $398 million; however, cash flows provided by investing activities for the six months ended June 30, 2008, increased $126 million compared to the same period in 2007. The increase is primarily due to a decrease of $49 million in purchases of property, plant and equipment, a decrease of $59 million in contributions to unconsolidated investments and a favorable effect on cash of $64 million from the reconsolidation of our Canadian subsidiaries for the six months ended June 30, 2008, as compared to an unfavorable effect on cash of $29 million for the deconsolidation of OMEC for the same period in 2007. Offsetting these increases in cash flows from investing activities was a lower return of investment in Greenfield LP of $24 million for the six months ended June 30, 2008, as compared to $92 million for the same period in 2007.

Our cash flows used in financing activities for the six months ended June 30, 2008, resulted in net outflows of $1.4 billion, as compared to cash provided by financing activities of $168 million for the same period in 2007. The increase in net cash outflow was primarily the result of our emergence from Chapter 11 and our recapitalization on the Effective Date. On and subsequent to the Effective Date, we borrowed $3.5 billion under our Exit Facilities and used cash on hand to repay our

Second Priority Debt of $3.7 billion in addition to cash payment of obligations under the Plan of Reorganization, working capital and other general corporate purposes. We also repaid $855 million of borrowings under our Exit Facilities during the six months ended June 30, 2008. Other increases in net cash outflows used for financing activities compared to the same period in 2007 are an increase of $95 million for repayments under the DIP Facility, an increase in redemption of preferred interests of $157 million and an increase of $127 million in financing costs, primarily related to closing on our Exit Facilities. Offsetting our cash flows used in financing activities for the six months ended June 30, 2008, were $103 million received from project refinancings, net of project financing repayments, compared to net outflows of $54 million for the same period in 2007 and $34 million received from the settlement of derivatives. During the six months ended June 30, 2007, our primarily source of cash provided by financing activities were proceeds of $614 million from borrowings under the DIP Facility, which was partially offset by payments of $224 million to repay a portion of the CalGen Secured Debt, $89 million for notes payable and other lines of credit, net repayments of $54 million under project financings and $60 million in financing costs related to the refinancing in March 2007 of the Original DIP Facility with the DIP Facility.

Letter of Credit Facilities — At June 30, 2008, we had a total of $476 million in amounts outstanding under letters of credit including $254 million under our Exit Credit Facility and $115 million under the letter of credit facility related to our subsidiary Calpine Development Holdings, Inc., as well as amounts outstanding under other credit facilities.

Margin Deposits and Other Credit Support — 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 gas agreements that qualify as “eligible commodity hedge agreements” under the Exit Credit Facility, and under 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 will share the benefits of the collateral subject to such first priority liens ratably with the lenders under the Exit Credit Facility. Such first priority liens had also been permitted under the DIP Facility prior to the conversion of the loans and commitments under the DIP Facility to our exit financing under the Exit Credit Facility. See Note 9 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.

Future collateral requirements for cash, first priority liens and letters of credit may increase based on the extent of our involvement in standard contracts and movements in commodity prices and also based on our credit ratings and general perception of creditworthiness in our market. While we believe that we have adequate liquidity to support our operations at this time, it is difficult to predict future developments and the amount of credit support that we may need to provide as part of our business operations.

Asset Sales and Purchase of Investment — A significant component of our restructuring activities has been to return our focus to our core strategic assets and selectively dispose of or restructure certain less strategically important assets. As a result of the review of our asset portfolio, we sold or otherwise disposed of the following assets, and acquired the RockGen assets, which had previously been leased.

Asset	Transaction Description	Closing Date	Consideration
RockGen Energy Center	Purchase of investment	January 15, 2008	$145 million allowed unsecured claim
Hillabee development project	Sale of assets	February 14, 2008	$156 million
Fremont development project	Sale of assets	March 5, 2008	$254 million

Potential Loss on Deconsolidation/Sale of Auburndale Power Plant — Auburndale, our consolidated subsidiary, is a variable interest entity. Pomifer, an unrelated party, holds a preferred interest in Auburndale, which entitles Pomifer to approximately 70% of Auburndale’s cash distributions through 2013. Pomifer also has an option which, upon exercise, would entitle Pomifer to an additional cash distribution of 20% for a cash strike price, giving Pomifer a right to a total of approximately 90% of Auburndale’s cash distributions through 2013. In August 2008, Pomifer notified us that it intends to exercise its option to increase its share of cash distributions to 90%. Pomifer’s exercise of this option may result in a determination that we no longer absorb the majority of expected losses and residual returns of Auburndale, such that we no longer are the primary beneficiary of Auburndale. In addition, on June 3, 2008, Pomifer notified us of its intent to sell its preferred interest in Auburndale and that it had also initiated a third-party sales process requesting bids for 100% of Auburndale. Pomifer has certain “drag-along” rights over our equity interest in Auburndale, which would require us to sell our equity interest in Auburndale to a third party. See Note 12 of the Notes to Consolidated Condensed Financial Statements for a further discussion related to the potential deconsolidation or sale of Auburndale.

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.), Calpine Deer Park Partner, LLC, Calpine DP, LLC, Deer Park Energy Center Limited Partnership, CCFC Preferred Holdings, LLC, Metcalf Energy Center, LLC and Russell City Energy Company, LLC.

Recent Regulatory Developments

As discussed in our 2007 Form 10-K, to facilitate attainment of its ozone and fine particulates standards issued in 1997, the EPA promulgated regulations in March 2005 called the Clean Air Interstate Rule, or CAIR, applicable to 28 eastern states and the District of Columbia. When fully implemented, CAIR would have reduced SO_2 emissions in these states by over 70%, and NOx emissions by over 60%, from 2003 levels. On July 11, 2008, the United States Court of Appeals for the D.C. Circuit invalidated CAIR, stating that the CAIR regional cap-and-trade program cannot be used to facilitate attainment of the ozone and fine particulates standards. The court did not overturn the existing cap-and-trade program for SO_2 reductions under the acid rain program or the existing ozone season cap-and-trade program. At this time, we cannot predict the outcome of the legal proceedings related to the court’s decision, what action the EPA will take in response to this decision and the timing of such action, or the ultimate impact on us of these proceedings and resulting regulatory and other actions.

Financial Market Risks

As we are primarily focused on the generation of electricity using gas-fired turbines, our natural physical commodity risk is an option to be “short” fuel (i.e., natural gas buyer) and “long” power (i.e., electricity seller) at our generation’s cost of conversion. As a result, we are exposed to commodity price volatility in the markets in which our plants operate. We utilize derivatives, which are defined in SFAS No. 133, “Accounting for Derivative Instruments and Hedging Activities” to include physical commodity contracts and commodity financial instruments such as swaps, options, and forward contracts, to maximize the risk-adjusted returns from our power and gas assets. We conduct these hedging and optimization activities within a structured risk management framework based on clearly communicated controls, policies and procedures. We monitor these activities through active and ongoing management and oversight, clearly defined roles and responsibilities, and daily risk measurement and reporting. Additionally, we manage the associated risks through diversification, by controlling position sizes, by using portfolio position limits, and by entering into offsetting positions.

Derivative contracts are measured at their fair value and recorded as either assets or liabilities unless exempted from derivative treatment as a normal purchase and sale. 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.

Along with our portfolio of hedging transactions, we enter into electricity and natural gas trading 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. While our trading in electricity and natural gas is mostly physical in nature, we also engage in trading 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 discovery 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. Trading positions are included in and subject to our consolidated risk management portfolio position limits and controls structure. Changes in fair value of commodity trading positions 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 trading activities are subject to change as determined by our commercial operations group, senior management, Chief Risk Officer and Board of Directors.

Effective January 1, 2008, we adopted SFAS No. 157, which provides a framework for measuring fair value under GAAP and, among other things, requires enhanced disclosures about assets and liabilities carried at fair value. See Note 8 of the Notes to Consolidated Condensed Financial Statements for further discussion related to the adoption of this standard.

Derivatives — We enter into a variety of derivative instruments to include both exchange traded and OTC power and gas forwards, options and interest rate swaps.

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

Our level 2 fair value derivative instruments primarily consist of our interest rate swaps and our power and gas OTC 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 power and gas OTC forwards and options where pricing inputs are unobservable as well as our complex and structured transactions. Complex or structured transactions are tailored to 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 SFAS No. 157 and include in level 3 all of those whose fair value is based on significant unobservable inputs.

Under our risk management policy, most of our level 3 derivatives primarily act as hedges to our asset portfolio. Accordingly, the majority of the unrealized gains and losses are recorded in accumulated other comprehensive income (loss). As of June 30, 2008, our level 3 derivative assets and liabilities represent approximately 14% and 20% of our total assets and total liabilities, respectively. The actual amounts that will ultimately be settled will likely vary based on changes in gas prices and power prices as well as changes in interest rates. Such variances could be material. We validate our price inputs used in our fair value models quarterly through comparisons and validations of our commodity and interest rate pricing curves to prices from external sources such as the Intercontinental Exchange, British Bankers Association and other public sources. The majority of our derivative instruments have terms of five years or less. See further discussion of pre-tax gains (losses) currently held in AOCI in Note 9 of the Notes to Consolidated Condensed Financial Statements. The fair value of our derivatives include the credit standing of the counterparties involved and the impact of credit enhancements, if any. Such valuation adjustments are generally based on market evidence, if available, or management's best estimate.

Mark-to-market activity, a component within operating revenues (for electricity contracts), fuel and purchased energy expense (for gas contracts), and interest expense for interest rate swaps as shown on our Consolidated Condensed Statements of Operations include realized settlements of and unrealized mark-to-market gains and losses on power and gas derivative instruments not designated as cash flow hedges, including those held for trading purposes and for undesignated interest rate swaps together with ineffectiveness on such derivatives designated as cash flow hedges. See Note 9 of the Notes to

Consolidated Condensed Financial Statements for a discussion of our total mark-to-market activity for the three and six months ended June 30, 2008 and 2007.

The change in fair value of our outstanding commodity and interest rate swap derivative instruments from January 1, 2008, through June 30, 2008, is summarized in the table below (in millions):

	Interest Rate Swaps	Commodity Instruments	Total
Fair value of contracts outstanding at January 1, 2008[(1)]	$ (169)	$ (216)	$ (385)
Losses recognized or otherwise settled during the period[(2)]	31	67	98
Fair value attributable to new contracts	(14)	7	(7)
Changes in fair value attributable to price movements	40	(534)	(494)
Change in fair value attributable to adoption of SFAS No. 157	2	18	20
Fair value of contracts outstanding at June 30, 2008[(3)]	$ (110)	$ (658)	$ (768)

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(1) Reflects our portfolio of derivative assets and liabilities as of December 31, 2007, adjusted for the day one loss of $(22) million recognized upon adoption of SFAS No. 157 on January 1, 2008.

(2) Commodity gains (losses) recognized consist of (i) recognized gains from commodity cash flow hedges of $20 million (which represents a portion of the realized value of cash flow hedge activity of $8 million as disclosed in Note 9 of the Notes to Consolidated Condensed Financial Statements), (ii) losses related to deferred items of $(19) million, and (iii) losses related to undesignated derivatives of $(68) million (represents a portion of operating revenues and fuel and purchased energy expense as reported on our Consolidated Condensed Statements of Operations).

(3) Net commodity and interest rate swap derivative liabilities reported in Notes 8 and 9 of the Notes to Consolidated Condensed Financial Statements.

Our increased accumulated loss in AOCI was primarily driven by an increase in power prices on commodity hedges and a decrease in interest rates on interest rate swap derivatives.

Of the total mark-to-market gain (loss) of $24 million and $(127) million from commodity derivative instruments for the three and six months ended June 30, 2008, which is included in both operating revenues and fuel and purchased energy expense, there was a realized loss of $(99) million and $(63) million, and an unrealized gain (loss) of $123 million and $(64) million, respectively. The total mark-to-market gain (loss) included a non-cash gain of approximately $11 million and $20 million from amortization of various items for the three and six months ended June 30, 2008, respectively.

The fair value of outstanding derivative commodity instruments at June 30, 2008, based on price source and the period during which the instruments will mature, are summarized in the table below (in millions):

Fair Value Source	2008	2009-2010	2011-2012	After 2012	Total
Prices actively quoted	$ 526	$ 5	$ —	$ —	$ 531
Prices provided by other external sources	(760)	(425)	(4)	—	(1,189)
Total fair value	$ (234)	$ (420)	$ (4)	$ —	$ (658)

The counterparty credit quality associated with the fair value of outstanding derivative commodity instruments at June 30, 2008, 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, 2008)	2008	2009-2010	2011-2012	After 2012	Total
Investment grade	$ 68	$ 38	$ (6)	$ —	$ 100
No external ratings	(302)	(458)	2	—	(758)
Total fair value	$ (234)	$ (420)	$ (4)	$ —	$ (658)

The fair value of our interest rate swaps are validated based upon external quotes. See further discussion on our interest rate swaps in the "—Interest Rate Risk" section below.

The primary factors affecting 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 electricity and natural gas and changes in interest rates. In that prices for electricity and natural gas are among the most volatile of all commodity prices, there may be material changes in the fair value of our derivatives over time, driven both by price volatility and the changes in volume of open derivative transactions. The change since the last balance sheet date in the total value of the derivatives (both assets and liabilities) is reflected either in OCI, net of tax, or on our Consolidated Condensed Statements of Operations as a component (gain or loss) of current earnings. As of June 30, 2008, and December 31, 2007, a component of the balance in AOCI represented the unrealized net loss associated with commodity cash flow hedging transactions. As noted above, there is a substantial amount of volatility inherent in accounting for the fair value of these derivatives, and our results during the three and six months ended June 30, 2008 and 2007 have reflected this. See Notes 8 and 9 of the Notes to Consolidated Condensed Financial Statements for additional information on derivative activity.

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

We measure the commodity price risks in our portfolio on a daily basis using a VAR model to determine 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, generating facilities, 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, 2008, as well as our VAR at June 30, 2008 (in millions):

	2008
Three months ended June 30:	
High	$ 70
Low	$ 47
Average	$ 56
Six months ended June 30:	
High	$ 70
Low	$ 39
Average	$ 50
As of June 30	$ 66

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 $7.6 billion of our variable rate debt through December 31, 2009, through the use of variable to fixed interest rate swaps. The majority of our interest rate swaps mature in years 2010 through 2013. See the table below for additional illustration of our interest rate swaps. 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.

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, 2008. All outstanding balances and fair market values are shown gross of applicable premium or discount, if any (in millions):

	2008	2009	2010	2011	2012	Thereafter	Total	Fair Value June 30, 2008
Debt by Maturity Date:								
Fixed Rate	$ 107	$ 219	$ 254	$ 128	$ 86	$ 759	$ 1,553	$ 1,532
Average Interest Rate	6.5%	7.1%	7.8%	9.0%	11.3%	9.2%		
Variable Rate	$ 44	$ 448	$ 83	$ 1,724	$ 74	$ 6,512	$ 8,885	$ 8,628
Average Interest Rate	5.5%	8.5%	6.1%	9.4%	6.7%	7.7%		
Interest Rate Derivative Instruments (Notional Value):								
Variable to Fixed Swaps[(1)]	$ 7,572	$ 7,572	$ 7,175	$ 4,905	$ 3,870	$ 66	n/a	$ (110)
Average Pay Rate	4.1%	4.3%	4.4%	4.5%	4.6%	3.5%		
Average Receive Rate	2.8%	3.4%	3.7%	4.0%	4.2%	4.5%		

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(1) Includes interest rate swaps where forecasted issuance of variable rate debt is deemed probable.

Recent Accounting Pronouncements

See Note 1 of the Notes to Consolidated Condensed Financial Statements for a discussion of recent accounting pronouncements.

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

See “Financial Market Risks” 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 Exchange Act Rule 13a-15. 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 2008, 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.

Limitations on the Effectiveness of Controls

Our management, including our Chief Executive Officer and Chief Financial Officer, does not expect that our disclosure controls or our internal controls will prevent or detect all errors and all fraud. A control system, no matter how well designed and operated, can provide only reasonable, not absolute, assurance that the control system's objectives will be met. Further, the design of a control system must reflect the fact that there are resource constraints, and the benefits of controls must be considered relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, within Calpine have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty, and that breakdowns can occur because of simple error or mistake. Controls can also be circumvented by the individual acts of some persons, by collusion of two or more people or by management override of the controls. The design of any system of controls is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Over time, controls may become inadequate because of changes in conditions or deterioration in the degree of compliance with associated policies or procedures. Because of the inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

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 6. *Exhibits*

The following exhibits are filed herewith unless otherwise indicated:

Exhibit Number	Description
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 By-Laws of the Company (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K, filed with the SEC on February 1, 2008).
10.1.1	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 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on July 14, 2008).
10.2.1	Letter Agreement and Addendum dated June 30, 2008, between the Company and Zamir Rauf (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on July 3, 2008).†
10.2.2	Employment Agreement, dated June 19, 2006, between the Company and Gregory L. Doody (incorporated by reference to Exhibit 10.5.15 to the Company's Annual Report on Form 10-K for the year ended December 31, 2006, filed with the SEC on March 14, 2007).†
10.2.3	Amendment, dated July 16, 2008, to Employment Agreement, dated June 19, 2006, between the Company and Gregory L. Doody (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed with the SEC on July 22, 2008).†
10.2.4	Letter Agreement re Employment Separation, dated April 7, 2008 (executed April 11, 2008), between the Company and Charles B. Clark, Jr. (incorporated by reference to Exhibit 10.3.1 to the Company's Quarterly Report on Form 10-Q filed with the SEC on May 12, 2008).†
10.2.5	Consulting Agreement, effective May 30, 2008, between the Company and Charles B. Clark, Jr. (incorporated by reference to Exhibit 10.3.2 to the Company's Quarterly Report on Form 10-Q filed with the SEC on May 12, 2008).†
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.

† Management contract or compensatory plan or arrangement.

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
Interim Executive Vice President and
Interim Chief Financial Officer
(principal financial officer)

Date: August 8, 2008

By: /s/ STEVEN F. HODKINSON
Steven F. Hodkinson
Interim Corporate Controller
(principal accounting officer)

Date: August 8, 2008

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* Filed herewith.

† Management contract or compensatory plan or arrangement.

EXHIBIT 31.1

CERTIFICATIONS

I, Robert P. May, 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: August 8, 2008

/s/ Robert P. May

Robert P. May
CHIEF EXECUTIVE OFFICER
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: August 8, 2008

/s/ Zamir Rauf

Zamir Rauf
INTERIM EXECUTIVE VICE PRESIDENT AND
INTERIM 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, 2008, 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/ ROBERT P. MAY	/s/ ZAMIR RAUF
Robert P. May	Zamir Rauf
Chief Executive Officer	Interim Executive Vice President and
Calpine Corporation	Interim Chief Financial Officer
	Calpine Corporation

Dated: August 8, 2008

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.