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 September 30, 2007

or

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

For the transition period from to

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: (408) 995-5115

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer. See definition of "accelerated filer and large accelerated filer" in Rule 12b-2 of the Exchange Act. (Check one):

Large accelerated filer [ ] Accelerated filer [X] Non-accelerated filer [ ]

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 the number of shares outstanding of each of the issuer's classes of common stock, as of the latest practicable date: 482,200,119 shares of Common Stock, par value $.001 per share, outstanding on November 2, 2007.

CALPINE CORPORATION AND SUBSIDIARIES
(Debtor-in-Possession)

REPORT ON FORM 10-Q

For the Quarter Ended September 30, 2007

INDEX

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. For clarification, such terms will not include the Canadian and other foreign subsidiaries that were deconsolidated as of the Petition Date, as a result of the filings by the Canadian Debtors under the CCAA in the Canadian Court. 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 filing of this Report.

ABBREVIATION	DEFINITION
2006 Form 10-K	Calpine Corporation's Annual Report on Form 10-K for the year ended December 31, 2006, filed with the SEC on March 14, 2007
2014 Convertible Notes	Calpine Corporation's Contingent Convertible Notes Due 2014
2015 Convertible Notes	Calpine Corporation's 7 3/4% Contingent Convertible Notes Due 2015
2023 Convertible Notes	Calpine Corporation's 4 3/4% Contingent Convertible Senior Notes Due 2023
345(b) Waiver Order	Order, dated May 4, 2006, pursuant to Section 345(b) of the Bankruptcy Code authorizing continued use of existing investment guidelines and continued operation of certain bank accounts
401(k) Plan	Calpine Corporation Retirement Savings Plan
Acadia PP	Acadia Power Partners, LLC
AOCI	Accumulated Other Comprehensive Income
APH	Acadia Power Holdings, LLC, a wholly owned subsidiary of Cleco
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
Btu(s)	British thermal unit(s)
CAA	Federal Clean Air Act of 1970
Calgary Energy Centre	Calgary Energy Centre Limited Partnership
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 Term Loans Due 2009 issued by CalGen; and the CalGen First Priority Revolving Loans
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
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

ABBREVIATION	DEFINITION
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
CalGen Notes	Collectively, $235,000,000 First Priority Secured Floating Rate Notes Due 2009, $640,000,000 Second Priority Secured Floating Rate Notes Due 2010, $680,000,000 Third Priority Secured Floating Rate Notes Due 2011 and $150,000,000 11 1/2% Third Priority Secured Notes Due 2011, each issued by CalGen and CalGen Finance
CalGen Secured Debt	Collectively, the CalGen First Lien Debt, the CalGen Second Lien Debt and the CalGen Third Lien Debt
CalGen Term Loans	Collectively, $600,000,000 First Priority Secured Institutional Term Loans Due 2009 and $100,000,000 Second Priority Secured Institutional Term Loans Due 2010, each issued by CalGen
Calpine Debtor(s)	The U.S. Debtors and the Canadian Debtors
Canadian Court	The Court of Queen’s Bench of Alberta, Judicial District of Calgary
Canadian Debtor(s)	The subsidiaries and affiliates of Calpine Corporation that have been granted creditor protection under the CCAA in the Canadian Court
Canadian Settlement Agreement	Settlement Agreement dated as of July 24, 2007, by and between Calpine Corporation, on behalf of itself and its U.S. subsidiaries, Calpine Canada Energy Ltd., Calpine Canada Power Ltd., Calpine Canada Energy Finance ULC, Calpine Energy Services Canada Ltd., Calpine Canada Resources Company, Calpine Canada Power Services Ltd., Calpine Canada Energy Finance II ULC, Calpine Natural Gas Services Limited, 3094479 Nova Scotia Company, Calpine Energy Services Canada Partnership, Calpine Canada Natural Gas Partnership, Calpine Canadian Saltend Limited Partnership and HSBC Bank USA, National Association, as successor indenture trustee
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.
CCFCP	CCFC Preferred Holdings, LLC
CCRC	Calpine Canada Resources Company, formerly Calpine Canada Resources Ltd.
CDWR	California Department of Water Resources
CES	Calpine Energy Services, L.P.
CES-Canada	Calpine Energy Services Canada Partnership
Chapter 11	Chapter 11 of the Bankruptcy Code
Cleco	Cleco Corp.
Company	Calpine Corporation, a Delaware corporation, and subsidiaries
Convertible Notes	Collectively, the 2014 Convertible Notes, the 2015 Convertible Notes, the 2023 Convertible Notes and Calpine Corporation’s 4% Convertible Senior Notes due 2006
Creditors’ Committee	The Official Committee of Unsecured Creditors of Calpine Corporation appointed by the Office of the U.S. Trustee

ABBREVIATION	DEFINITION
DB London	Deutsche Bank AG London
Deer Park	Deer Park Energy Center Limited Partnership
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
DIP Order	Order of the U.S. Bankruptcy Court dated March 12, 2007, approving the DIP Facility
Disclosure Statement	Disclosure Statement for Debtors' Joint Plan of Reorganization Pursuant to Chapter 11 of the United States Bankruptcy Code filed by the U.S. Debtors with the U.S. Bankruptcy Court on June 20, 2007, as amended, modified or supplemented through the filing of this Report, and as it may be further amended, modified or supplemented from time to time
EBITDA	Earnings before interest, taxes, depreciation, and amortization
EPA	U.S. Environmental Protection Agency
ERISA	Employee Retirement Income Security Act
ERO	Electric Reliability Organization
Exchange Act	U.S. Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FERC	Federal Energy Regulatory Commission
FFIC	Fireman's Fund Insurance Company
FIN	FASB Interpretation Number
First Priority Notes	9 5/8% First Priority Senior Secured Notes Due 2014
First Priority Trustee	Until February 2, 2006, Wilmington Trust Company, as trustee, and from February 3, 2006, and thereafter, Law Debenture Trust Company of New York, as successor trustee, under the Indenture, dated as of September 30, 2004, with respect to the First Priority Notes
FPA	Federal Power Act
FSP	FASB Staff Position
GAAP	Generally accepted accounting principles in the U.S.
Geysers Assets	19 geothermal power plant assets located in northern California
GHG	Greenhouse gases
Greenfield LP	Greenfield Energy Centre LP
Harbert Convertible Fund	Harbert Convertible Arbitrage Master Fund, L.P.
Harbert Distressed Fund	Harbert Distressed Investment Master Fund, Ltd.
Heat Rate	A measure of the amount of fuel required to produce a unit of electricity
IRS	U.S. Internal Revenue Service
King City Cogen	Calpine King City Cogen, LLC
KWh	Kilowatt hour(s)

ABBREVIATION	DEFINITION
LIBOR	London Inter-Bank Offered Rate
LSTC	Liabilities subject to compromise
Metcalf	Metcalf Energy Center, LLC
MMBtu	Million Btu
Moapa	Moapa Energy Center, LLC
MW	Megawatt(s)
MWh	Megawatt hour(s)
NERC	North American Electric Reliability Council
Ninth Circuit Court of Appeals	U.S. Court of Appeals for the Ninth Circuit
NOL(s)	Net operating loss(es)
Non-Debtor(s)	The subsidiaries and affiliates of Calpine Corporation that are not Calpine Debtors
Non-U.S. Debtor(s)	The consolidated subsidiaries and affiliates of Calpine Corporation that are not U.S. Debtor(s)
Northern District Court	U.S. District Court for the Northern District of California
NPC	Nevada Power Company
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
Panda	Panda Energy International, Inc., and related party PLC II, LLC
PCF	Power Contract Financing, L.L.C.
PCF III	Power Contract Financing III, LLC
Petition Date	December 20, 2005
Plan of Reorganization	Debtors' Joint Plan of Reorganization Pursuant to Chapter 11 of the United States Bankruptcy Code filed by the U.S. Debtors with the U.S. Bankruptcy Court on June 20, 2007, as amended, modified or supplemented through the filing of this Report, and as it may be further amended, modified or supplemented from time to time

ABBREVIATION	DEFINITION
Plan Supplement	Supplement to Debtors' Joint Plan of Reorganization Pursuant to Chapter 11 of the United States Bankruptcy Code filed by the U.S. Debtors with the U.S. Bankruptcy Court on June 20, 2007, as amended, modified or supplemented through the filing of this Report, and as it may be further amended, modified or supplemented from time to time
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
PSM	Power Systems Manufacturing, LLC
RMR Contract(s)	Reliability Must Run contract(s)
Rosetta	Rosetta Resources, Inc.
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 Priority Debt	Collectively, the Second Priority Notes and Calpine Corporation's 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
SPPC	Sierra Pacific Power Company
TSA(s)	Transmission service agreement(s)
ULC I	Calpine Canada Energy Finance ULC
ULC II	Calpine Canada Energy Finance II ULC
Unsecured Notes	Collectively, Calpine Corporation's 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, which constitutes a portion of Calpine Corporation's unsecured senior notes
Unsecured Noteholders	Collectively, the holders of the Unsecured Notes
U.S.	United States of America
U.S. Bankruptcy Court	U.S. Bankruptcy Court for the Southern District of New York
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)

PART I — FINANCIAL INFORMATION

Item 1. Financial Statements.

CALPINE CORPORATION AND SUBSIDIARIES
(DEBTOR-IN-POSSESSION)

CONSOLIDATED CONDENSED BALANCE SHEETS
September 30, 2007 and December 31, 2006
(Unaudited)

	September 30, 2007	December 31, 2006
	(in millions, except share and per share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,703	$ 1,077
Accounts receivable, net of allowance of $54 and $32	1,047	735
Inventories	117	184
Margin deposits and other prepaid expense	395	359
Restricted cash, current	406	426
Current derivative assets	227	152
Assets held for sale	198	154
Other current assets	55	81
Total current assets	4,148	3,168
Property, plant and equipment, net	12,452	13,603
Restricted cash, net of current portion	155	192
Investments	249	129
Long-term derivative assets	257	352
Other assets	972	1,146
Total assets	$ 18,233	$ 18,590
LIABILITIES & STOCKHOLDERS' DEFICIT		
Current liabilities:		
Accounts payable	$ 614	$ 440
Accrued interest payable	187	406
Debt, current	4,875	4,569
Current derivative liabilities	280	225
Income taxes payable	39	99
Other current liabilities	466	319
Total current liabilities	6,461	6,058
Debt, net of current portion	3,129	3,352
Deferred income taxes, net of current portion	655	490
Long-term derivative liabilities	429	475
Other long-term liabilities	269	345
Total liabilities not subject to compromise	10,943	10,720
Liabilities subject to compromise	11,667	14,757
Commitments and contingencies (see Note 10)		
Minority interest	8	266
Stockholders' equity (deficit):		
Preferred stock, $.001 par value per share; authorized 10,000,000 shares; none issued and outstanding in 2007 and 2006	—	—
Common stock, $.001 par value per share; authorized 2,000,000,000 shares; 568,772,999 issued and 482,200,119 outstanding in 2007 and 568,764,920 issued and 529,764,920 outstanding in 2006	1	1
Additional paid-in capital	3,270	3,270
Additional paid-in capital, loaned shares	7	145
Additional paid-in capital, returnable shares	(7)	(145)
Accumulated deficit	(7,543)	(10,378)
Accumulated other comprehensive loss	(113)	(46)
Total stockholders' deficit	(4,385)	(7,153)
Total liabilities and stockholders' deficit	$ 18,233	$ 18,590

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

CALPINE CORPORATION AND SUBSIDIARIES
(DEBTOR-IN-POSSESSION)

CONSOLIDATED CONDENSED STATEMENTS OF OPERATIONS
For the Three and Nine Months Ended September 30, 2007 and 2006
(Unaudited)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(in millions, except share and per share amounts)			
Revenue:				
Electricity and steam revenue	$ 1,690	$ 1,842	$ 4,412	$ 4,070
Sales of purchased power and gas for hedging and optimization	540	273	1,357	891
Mark-to-market activities, net	2	28	5	88
Other revenue	7	15	55	57
Total revenue	2,239	2,158	5,829	5,106
Cost of revenue:				
Plant operating expense	182	175	561	520
Purchased power and gas expense for hedging and optimization	370	296	1,046	857
Fuel expense	1,114	1,106	2,989	2,474
Depreciation and amortization expense	114	121	350	350
Operating plant impairments	—	—	—	53
Operating lease expense	15	11	39	53
Other cost of revenue	32	39	112	128
Total cost of revenue	1,827	1,748	5,097	4,435
Gross profit	412	410	732	671
Equipment, development project and other impairments	—	(4)	2	64
Sales, general and administrative expense	33	49	112	147
Other operating expense	12	10	22	25
Income from operations	367	355	596	435
Interest expense	602	228	1,176	820
Interest (income)	(14)	(19)	(48)	(59)
Minority interest expense	1	7	—	10
Other (income) expense, net	(127)	(10)	(134)	7
Income (loss) before reorganization items and income taxes	(95)	149	(398)	(343)
Reorganization items	(3,940)	146	(3,366)	1,099
Income (loss) before income taxes	3,845	3	2,968	(1,442)
Provision (benefit) for income taxes	51	1	133	(36)
Income (loss) before cumulative effect of a change in accounting principle	3,794	2	2,835	(1,406)
Cumulative effect of a change in accounting principle, net of tax	—	—	—	1
Net income (loss)	$ 3,794	$ 2	$ 2,835	$ (1,405)
Basic earnings (loss) per common share:				
Weighted average shares of common stock outstanding (in thousands)	479,312	479,136	479,208	479,136
Income (loss) before cumulative effect of a change in accounting principle	$ 7.92	$ —	$ 5.92	$ (2.93)
Cumulative effect of a change in accounting principle, net of tax	—	—	—	—
Net income (loss)	$ 7.92	$ —	$ 5.92	$ (2.93)
Diluted earnings (loss) per common share:				
Weighted average shares of common stock outstanding (in thousands)	479,617	479,136	479,543	479,136
Income (loss) before cumulative effect of a change in accounting principle	$ 7.91	$ —	$ 5.91	$ (2.93)
Cumulative effect of a change in accounting principle, net of tax	—	—	—	—
Net income (loss)	$ 7.91	$ —	$ 5.91	$ (2.93)

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

CALPINE CORPORATION AND SUBSIDIARIES
(DEBTOR-IN-POSSESSION)

CONSOLIDATED CONDENSED STATEMENTS OF CASH FLOWS
For the Nine Months Ended September 30, 2007 and 2006
(Unaudited)

	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(in millions)	
Cash flows from operating activities:		
Net income (loss)	$ 2,835	$ (1,405)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:		
Depreciation and amortization[1]	420	437
Impairment charges	2	117
Deferred income taxes, net	132	(36)
Loss on sale of assets, excluding reorganization items	24	2
Foreign currency transaction gain, excluding reorganization items	(2)	(2)
Gain on settlement of notes receivable	—	(6)
Mark-to-market activities, net	(5)	(88)
Non-cash derivative activities	2	120
Non-cash reorganization items	(3,459)	976
Other	5	34
Change in operating assets and liabilities, net of effects of acquisitions:		
Accounts receivable	(316)	155
Other assets	19	22
Accounts payable, liabilities subject to compromise and accrued expenses	383	(238)
Other liabilities	53	79
Net cash provided by operating activities	93	167
Cash flows from investing activities:		
Purchases of property, plant and equipment	(173)	(159)
Disposals of property, plant and equipment	32	13
Acquisitions, net of cash acquired	—	(267)
Disposals of investments, turbines and power plants	507	38
Advances to joint ventures	(73)	(31)
Return of investment in Canadian Debtors	75	—
Return of investment in joint ventures	104	—
Cash flows from derivatives not designated as hedges	(21)	(95)
Decrease in restricted cash	57	442
Cash effect of deconsolidation of OMEC	(29)	—
Other	4	13
Net cash provided by (used in) investing activities	483	(46)

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

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

	Nine Months Ended September 30, 2007	2006
	(in millions)	
Cash flows from financing activities:		
Repayments of notes payable and lines of credit	$ (135)	$ (174)
Borrowings under project financing	16	121
Repayments of project financing	(108)	(109)
Repayments of CalGen Secured Debt	(224)	—
Borrowings under DIP Facility	614	1,150
Repayments of DIP Facility	(28)	(178)
Repayments and repurchases of Senior Notes	—	(646)
Redemptions of preferred interests	(9)	(9)
Financing costs	(81)	(34)
Other	5	(21)
Net cash provided by financing activities	50	100
Net increase in cash and cash equivalents, including discontinued operations cash	626	221
Change in discontinued operations cash classified as assets held for sale	—	(18)
Net increase in cash and cash equivalents	626	203
Cash and cash equivalents, beginning of period	1,077	786
Cash and cash equivalents, end of period	$ 1,703	$ 989
Cash paid (received) during the period for:		
Interest, net of amounts capitalized	$ 926	$ 772
Income taxes	$ 1	$ —
Reorganization items included in operating activities, net	$ 88	$ 78
Reorganization items included in investing activities, net	$ (582)	$ —
Reorganization items included in financing activities, net	$ 74	$ 34

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

	Nine Months Ended September 30, 2007	2006
	(in millions)	
Supplemental disclosure of non-cash investing and financing activities:		
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	$ 138	$ 72
Letter of credit draws under the CalGen Secured Debt used for operating activities	$ 16	$ 71
Capital contribution (equipment) to Greenfield LP	$ —	$ 28
Fair value of Metcalf cooperation agreement, with offsets to notes payable ($6) and operating liabilities ($6)	$ 12	$ —
Acquisition of property, plant and equipment for Geysers Assets, with offsets to operating assets	$ —	$ 181

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

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 our 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, 2006, included in our 2006 Form 10-K. The results for interim periods are not necessarily indicative of the results for the entire year.

We are engaged in predominantly one line of business, the generation and sale of electricity and electricity-related products. We manage and operate our business as a single segment, and, therefore, no segment information is presented.

On May 3, 2007, OMEC, an indirect wholly owned subsidiary and the owner of the Otay Mesa Energy Center, entered into a ten-year tolling agreement with SDG&E. OMEC also entered into a ground sublease and easement agreement with SDG&E 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 power plant at the end of the tolling agreement. OMEC is a variable interest entity. The tolling agreement and the put and call options were determined to absorb the majority of risk from the entity such that we are not OMEC's primary beneficiary. Accordingly, we deconsolidated OMEC during the second quarter of 2007, and our investment in OMEC is accounted for under the equity method. The deconsolidation of OMEC resulted in a reduction in construction in progress of $144 million, cash of $29 million, debt of $7 million, other current and non-current assets of $12 million and other current and non-current liabilities of $22 million. See Note 4 for further discussion.

Reclassifications — Certain prior years' amounts on the Consolidated Condensed Financial Statements were reclassified to conform to the current period presentation.

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 under such project finance facilities, and the use of certain cash balances on deposit in such accounts is limited, at least temporarily, to the operations of the respective projects. At September 30, 2007, and December 31, 2006, $198 million and $391 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 on the Consolidated Condensed Balance Sheets and Statements of Cash Flows.

The table below represents the components of our consolidated restricted cash as of September 30, 2007, and December 31, 2006 (in millions):

	September 30, 2007			December 31, 2006		
	Current	Non-Current	Total	Current	Non-Current	Total
Debt service	$ 88	$ 111	$ 199	$ 148	$ 114	$ 262
Rent reserve	13	—	13	58	—	58
Construction/major maintenance	99	22	121	83	28	111
Security/project reserves	151	—	151	46	32	78
Collateralized letters of credit and other credit support	4	—	4	29	—	29
Other	51	22	73	62	18	80
Total	$ 406	$ 155	$ 561	$ 426	$ 192	$ 618

Commodity Margin Deposits and Other Collateral — As of September 30, 2007, and December 31, 2006, to support commodity transactions, we had margin deposits with third parties of $249 million and $214 million, respectively. Counterparties had margin deposits with us of $41 million and nil at September 30, 2007, and December 31, 2006, respectively. In addition, we have granted additional first priority liens on the assets currently subject to first priority liens under the DIP Facility as collateral under certain of our power agreements, natural gas agreements and interest rate swap agreements that qualify as "eligible commodity hedge agreements" under the DIP Facility 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 DIP Facility. As of September 30, 2007, and December 31, 2006, our net discounted exposure under the power and natural gas agreements collateralized by such first priority liens was approximately $4 million and nil, respectively, and our net discounted exposure under the interest rate swap agreements collateralized by such first priority liens was approximately $51 million and nil, respectively.

Income Taxes — For the three months ended September 30, 2007 and 2006, our effective tax rate was 1.3% and 42.0%, respectively. For the nine months ended September 30, 2007 and 2006, our effective tax rate was 4.5% and 2.5%, respectively. The quarterly tax provision on continuing operations was significantly impacted by the valuation allowance recorded against certain deferred tax assets. For the three and nine months ended September 30, 2007, we determined the annual effective tax rate method of computing the tax provision at the interim period did not provide meaningful results due to uncertainty in reliably estimating the projected annual effective tax rate for 2007. Therefore, income taxes for the three and nine months ended September 30, 2007, were computed based on actual results. We calculated our tax provision by netting deferred tax assets against deferred tax liabilities that we anticipate will be realized within the statutory carryforward period allowed under the Internal Revenue Code and relevant state tax statutes and established a valuation allowance against the remaining deferred tax assets.

The tax benefit or provision recorded on our Consolidated Condensed Statements of Operations is primarily the result of transactions (including asset impairments and dispositions) that impact the difference between the book and tax basis of our assets and the related deferred tax liabilities. The difference in the amount of the tax benefit or provision between the three and nine months ended September 30, 2007, as compared to the same periods in the prior year, relates primarily to the nature and amount of asset impairments or dispositions in the respective periods.

Under federal income tax law, a corporation is generally permitted to deduct from taxable income in any year NOLs carried forward from prior years, subject to certain time limitations as prescribed by the Internal Revenue Code. Our ability to deduct such NOL carryforwards could be subject to a significant limitation if we were to undergo an "ownership change" during or as a result of our Chapter 11 cases or the implementation of our Plan of Reorganization, which contemplates the cancellation of our outstanding common stock and the distribution of reorganized Calpine Corporation common stock. In order to allow us to preserve our ability to utilize our NOLs, the U.S. Bankruptcy Court has entered orders that place certain limitations on trading in our common stock or certain securities, including options, convertible into our common stock during the pendency of the Chapter 11 cases and has also provided potentially retroactive application of notice and sell-down procedures for trading in claims against the U.S. Debtors' estates, which claims trading could also negatively impact our accumulated NOLs and other tax attributes. In addition, we have proposed in our Plan of Reorganization restrictions on certain transfers of reorganized Calpine Corporation common stock following our emergence from Chapter 11 in order to allow us to take advantage of special rules under the Internal Revenue Code that apply when an “ownership change” occurs pursuant to the implementation of a plan of reorganization under the Bankruptcy Code. In general, these special rules allow for a more favorable utilization of NOL carryforwards than would otherwise have been available following an “ownership change” not in connection with a plan of reorganization. The ultimate realization of our NOLs will depend on several factors, such as whether limitations on trading in our common stock will prevent an “ownership change” and the amount of our indebtedness that is cancelled through the Chapter 11 cases. If a portion of our debt is cancelled upon emergence from Chapter 11, the amount of the cancelled debt would reduce tax attributes such as our NOLs and tax basis on fixed assets. Depending on the terms of our Plan of Reorganization ultimately confirmed, any income from debt cancellations could partially or fully utilize our available NOLs.

Additionally, the NOL carryforwards of CCFC (a Non-Debtor) may be limited due to transactions related to the preferred interests issued by CCFC’s indirect parent, CCFCP, which may be deemed an “ownership change” under federal income tax law. If an “ownership change” occurred, any limitation on the CCFC NOL carryforwards would not have a material impact on our Consolidated Condensed Financial Statements due to the full valuation allowance recorded against such carryforwards.

GAAP requires that all available evidence, both positive and negative, be considered 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. Primarily due to our inability to assume future profits and due to our reduced ability to implement tax-planning strategies to utilize our NOLs while in Chapter 11, we concluded that valuation allowances on a portion of our deferred tax assets were required.

In June 2006, the FASB issued FIN No. 48 “Accounting for Uncertainty in Income Taxes — An Interpretation of FASB Statement 109.” FIN 48 clarifies the accounting for income taxes by prescribing a minimum recognition threshold that a tax position is required to meet before being recognized in the financial statements. FIN 48 also provides guidance on derecognizing, measurement, classification, interest and penalties, accounting in interim periods, disclosure and transition.

We adopted FIN 48 on January 1, 2007, as required. As of that date, we had an accrued liability of approximately $153 million related to uncertain tax positions, primarily related to federal, state and withholding taxes. Also included are estimated interest and penalties that we record to income tax expense. However, due to our ongoing Chapter 11 cases, some portion of this accrued amount may not be paid until we emerge from Chapter 11. There was no effect on the January 1, 2007, accumulated deficit balance as a result of the adoption of FIN 48. However, as a result of the adoption of FIN 48, we reduced our deferred tax assets by approximately $106 million. The decrease in the deferred tax assets was offset by an equal reduction in the related valuation allowance. In addition, future changes in the accrued liability for uncertain tax positions are not expected to impact our effective tax rate in the foreseeable future due to the existence of the valuation allowances.

During the three months ended September 30, 2007, we increased our liability for uncertain tax positions by $11 million to reflect the impact of foreign currency fluctuations on Canadian denominated tax liabilities. During the nine months ended September 30, 2007, our liability for uncertain tax positions was unchanged as the increase during the third quarter of 2007 was offset by a decrease of $11 million during the first half of 2007, based on information contained in a recently issued IRS revenue agent report. As a result of these items, our liability for uncertain tax positions is $153 million at September 30, 2007. Within the next 12 months, we anticipate that we will resolve uncertain tax positions related to certain withholding taxes that we expect would result in a $75 million reduction of our liability for uncertain tax positions.

The IRS completed its field examination of our U.S. income tax returns for the 1999 through 2002 tax years. The U.S. Joint Committee on Taxation is currently reviewing the examination report and we expect the audit to be concluded during 2007. At that time, the 1999 through 2002 tax years will be effectively closed. We do not believe the examination will result in a material impact on our Consolidated Condensed Financial Statements. The 2003 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.

We are currently under examination in various states in which we operate. We anticipate that any state tax assessment will not have a material impact on our Consolidated Condensed Financial Statements. Following the deconsolidation of our Canadian and other foreign subsidiaries as of the Petition Date, we do not expect to incur any additional foreign tax liability.

Recent Accounting Pronouncements

SFAS No. 157

In September 2006, FASB issued SFAS No. 157, "Fair Value Measurements." SFAS No. 157 defines fair value, establishes a framework for measuring fair value in GAAP, and enhances disclosures about fair value measurements. SFAS No. 157 applies when other accounting pronouncements require fair value measurements; it does not require new fair value measurements. SFAS No. 157 is effective for fiscal years beginning after November 15, 2007, with early adoption encouraged. We are currently assessing the impact this standard will have on our results of operations, cash flows and financial position.

SFAS No. 159

In February 2007, FASB issued SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115." SFAS No. 159 permits entities to choose to measure many financial instruments and certain other items at fair value at specified election dates with unrealized gains and losses on items for which the fair value option has been elected to be reported in earnings at each subsequent reporting date. SFAS No. 159 also establishes presentation and disclosure requirements designed to facilitate comparisons between entities that choose different measurement attributes for similar types of assets and liabilities. SFAS No. 159 does not affect any existing accounting literature that requires certain assets and liabilities to be carried at fair value nor does it eliminate disclosure requirements included in other accounting standards, including requirements for disclosures about fair value measurements. SFAS No. 159 is effective for fiscal years beginning after November 15, 2007, with early adoption permitted provided that the entity also elects to apply SFAS No. 157. We are currently assessing the impact this standard will have on our results of operations, cash flows and financial position.

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 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. The guidance in FSP FIN 39-1 is effective for fiscal years beginning after November 15, 2007, with early application permitted. We expect that we will not elect to apply the netting provisions allowed under FSP FIN 39-1.

2. Chapter 11 Cases and Related Disclosures

Summary of Proceedings

General Bankruptcy Matters — Since the Petition Date, Calpine Corporation and 274 of its wholly owned subsidiaries in the U.S. have filed voluntary petitions for relief under Chapter 11 of the Bankruptcy Code in the U.S. Bankruptcy Court. Similarly, since the Petition Date, 12 of Calpine's Canadian subsidiaries have filed for creditor protection under the CCAA in the Canadian Court. Certain other subsidiaries could file under Chapter 11 in the U.S. or for creditor protection under the CCAA in Canada in the future. The information in this Report principally describes the Chapter 11 cases and only describes the CCAA proceedings where they have a material effect on our operations or where such information provides necessary background information.

The Calpine Debtors are continuing to operate their business as debtors-in-possession and will continue to conduct business in the ordinary course under the protection of the Bankruptcy Courts during the pendency of our Chapter 11 cases and CCAA proceedings. Generally, pursuant to automatic stay provisions under the Bankruptcy Code and orders (which currently extend through December 20, 2007) granted by the Canadian Court, while a plan or plans of reorganization (with respect to the U.S. Debtors) or arrangement (with respect to the Canadian Debtors) are developed, all actions to enforce or otherwise effect repayment of liabilities preceding the Petition Date as well as all pending litigation against the Calpine Debtors are stayed while the Calpine Debtors continue their business operations as debtors-in-possession.

As a result of our Chapter 11 filings and the other matters described herein, including uncertainties related to the fact that we have not yet had time to obtain confirmation of a plan or plans of reorganization, there is substantial doubt about our ability to continue as a going concern. Our ability to continue as a going concern, including our ability to meet our ongoing operational obligations, is dependent upon, among other things: (i) our ability to maintain adequate cash on hand; (ii) our ability to generate cash from operations; (iii) the cost, duration and outcome of our restructuring process; (iv) our ability to comply with the terms of our existing financing obligations and anticipated exit financing and the adequate assurance provisions of the Cash Collateral Order; and (v) our ability to achieve profitability following a restructuring. These challenges are in addition to those operational and competitive challenges faced by us in connection with our business. In conjunction with our advisors, we have implemented and continue to implement strategies to aid our liquidity and our ability to continue as a going concern. However, there can be no assurance as to the success of such efforts.

Plan of Reorganization — On June 20, 2007, the U.S. Debtors filed the Plan of Reorganization with the U.S. Bankruptcy Court, together with the Disclosure Statement and portions of the Plan Supplement. The Plan of Reorganization, as well as the Disclosure Statement and Plan Supplement have been amended several times since June 20, 2007.

The Plan of Reorganization provides for the treatment of claims of creditors on a "waterfall" basis that allocates value to our creditors and shareholders in accordance with the priorities of the Bankruptcy Code. Pursuant to the Plan of Reorganization, allowed administrative claims and priority tax claims would be paid in full in cash or cash equivalents, as would allowed first and second lien debt claims. Other allowed secured claims would be reinstated, paid in full in cash or cash equivalents, or have the collateral securing such claims returned to the secured creditor. Allowed unsecured claims would receive a pro rata distribution of common stock of the reorganized Calpine Corporation; allowed unsecured convenience claims (all claims $50,000 or less) would be paid in full in cash or cash equivalents. Any remaining value after such allowed creditors' claims have been paid would be distributed pro rata to existing holders of allowed interests (primarily holders of existing Calpine Corporation common stock) and holders of subordinated equity securities claims in the form of reorganized Calpine Corporation common stock.

The Plan of Reorganization assumes that allowed claims plus Non-Debtor net project debt of $3.9 billion will range from $20.3 billion to $22.0 billion after completion of the claims objection, reconciliation and resolution process. However, because disputed claims, including litigation instituted by us challenging so-called "make whole," premium, or "no-call" claims, have not yet been finally adjudicated, and our total enterprise value upon emergence has not yet been finally determined, no assurances can be given that actual recoveries to creditors and interest holders will not be materially higher or lower than proposed in the Plan of Reorganization. We intend to file an update to the valuation analysis of our total enterprise value upon emergence no later than ten days prior to the voting and objection deadline of November 30, 2007. The Disclosure Statement contains detailed information about the Plan of Reorganization, a historical profile of our business, a description of proposed distributions to creditors, and an analysis of the Plan of Reorganization's feasibility, as well as many of the technical matters required for the exit process, such as descriptions of who will be eligible to vote on the Plan of Reorganization and the voting process itself. The information contained in the Disclosure Statement is subject to change, whether as a result of further amendments to the Plan of Reorganization, actions of third parties or otherwise.

On September 25, 2007, the U.S. Bankruptcy Court approved the adequacy of the Disclosure Statement, the solicitation and notice procedures with respect to confirmation of the Plan of Reorganization and the form of various ballots and notices in connection therewith. The U.S. Bankruptcy Court established September 27, 2007, as the record date for determining eligibility to vote on the Plan of Reorganization. We completed the distribution of solicitation packages by October 5, 2007, the deadline for distribution set by the U.S. Bankruptcy Court.

The Plan of Reorganization will become effective only if it receives the requisite approval and is confirmed by the U.S. Bankruptcy Court. The voting and objection deadline with respect to the Plan of Reorganization is scheduled for November 30, 2007, at which time we expect that our Plan of Reorganization, as it may be further amended, will be accepted and approved by our creditors. The confirmation hearing in the U.S. Bankruptcy Court is scheduled to begin on December 17, 2007. If the U.S. Bankruptcy Court confirms the Plan of Reorganization, we expect to emerge from Chapter 11 shortly thereafter. However, there can be no assurance that we will be successful in obtaining the necessary votes to approve the Plan of Reorganization, that the U.S. Bankruptcy Court will confirm the Plan of Reorganization or that it will be implemented successfully.

We had the exclusive right until August 20, 2007, to solicit acceptance of the Plan of Reorganization. The exclusivity period has expired and competing plans of reorganization may be filed by third parties.

U.S. Debtors Condensed Combined Financial Statements

Condensed Combined Financial Statements of the U.S. Debtors are set forth below.

Condensed Combined Balance Sheets
September 30, 2007 and December 31, 2006

	U.S. Debtors	
	September 30, 2007	December 31, 2006
	(in millions)	
Assets:		
Current assets	$ 5,324	$ 4,746
Restricted cash, net of current portion	35	47
Investments	2,589	2,147
Property, plant and equipment, net	7,001	7,629
Other assets	964	1,192
Total assets	$ 15,913	$ 15,761
Liabilities not subject to compromise:		
Current liabilities	$ 5,739	$ 5,271
Long-term debt	409	411
Long-term derivative liabilities	365	375
Other long-term liabilities	578	454
Liabilities subject to compromise	13,385	16,453
Stockholders' deficit	(4,563)	(7,203)
Total liabilities and stockholders' deficit	$ 15,913	$ 15,761

Condensed Combined Statements of Operations
For the Three and Nine Months Ended September 30, 2007 and 2006

	U.S. Debtors			
	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(in millions)			
Total revenue	$ 2,163	$ 2,110	$ 5,509	$ 4,744
Total cost of revenue	1,916	1,929	5,348	4,501
Operating (income) expense[1]	(62)	(46)	(51)	134
Income from operations	309	227	212	109
Interest expense	498	113	876	503
Other (income) expense, net	(138)	(32)	(136)	(38)
Reorganization items	(3,833)	145	(3,348)	1,099
Provision for income taxes	40	30	110	7
Income (loss) before cumulative effect of a change in accounting principle	3,742	(29)	2,710	(1,462)
Cumulative effect of a change in accounting principle	—	—	—	1
Net income (loss)	$ 3,742	$ (29)	$ 2,710	$ (1,461)

(1) Includes equity in (income) loss of affiliates.

Condensed Combined Statements of Cash Flows
For the Nine Months Ended September 30, 2007 and 2006

	U.S. Debtors	
	2007	2006
	(in millions)	
Net cash provided by (used in):		
Operating activities	$ (54)	$ (113)
Investing activities	472	90
Financing activities	273	272
Net increase in cash and cash equivalents	691	249
Cash and cash equivalents, beginning of year	883	444
Effect on cash of new debtor filings	—	66
Cash and cash equivalents, end of year	$ 1,574	$ 759
Net cash paid for reorganization items included in operating activities	$ 88	$ 78
Net cash received from reorganization items included in investing activities	$ (577)	$ —
Net cash paid for reorganization items included in financing activities	$ 74	$ 34

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. However, the U.S. Debtors' Condensed Combined Balance Sheets include receivables from and payables to related Non-U.S. Debtor parties. Actual settlement of these related party receivables and payables is, by historical practice, made on a net basis.

Interest Expense — Due to the uncertainty with respect to whether our Plan of Reorganization as ultimately confirmed will include post-petition interest, which could become a substantial allowed claim, interest expense related to our pre-petition LSTC has been reported to date only to the extent that it will be paid during the pendency of our Chapter 11 cases or is permitted by the Cash Collateral Order or pursuant to orders of the U.S. Bankruptcy Court. Contractual interest (at non-default rates) to unrelated parties on LSTC not reflected on our Consolidated Condensed Financial Statements was $61 million and $158 million for the three months ended September 30, 2007 and 2006, respectively, and $181 million and $318 million for the nine months ended September 30, 2007 and 2006, respectively. Pursuant to the Cash Collateral Order, we make periodic cash adequate protection payments to the holders of Second Priority Debt; originally payments were made only through June 30, 2006, but, by order entered December 28, 2006, the U.S. Bankruptcy Court modified the Cash Collateral Order to provide for periodic adequate protection payments on a quarterly basis to the holders of the Second Priority Debt through December 31, 2007. Thereafter, unless we have a confirmed plan or plans of reorganization and are no longer subject to U.S. Bankruptcy Court jurisdiction, the holders of the Second Priority Debt must seek further orders from the U.S. Bankruptcy Court for any further amounts to be paid. We have not yet made a determination as to whether any portion of the adequate protection payments represents payment of principal and, therefore, have reported the full amount of the adequate protection payments as interest expense on our Consolidated Condensed Statements of Operations.

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 gains on the sale of assets related to our restructuring activities. Our restructuring activities may result in additional charges and other adjustments for expected allowed claims (including claims that have been allowed by the U.S. Bankruptcy Court) and other reorganization items that could be material to our financial position or results of operations in any given period. The table below lists the significant components of reorganization items for the three and nine months ended September 30, 2007 and 2006 (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Provision for expected allowed claims[(1)]	$ (4,030)	$ 94	$ (3,695)	$ 883
Gains on asset sales	(36)	—	(286)	—
Asset impairments[(2)]	—	—	120	2
DIP Facility financing and CalGen Secured Debt repayment costs	22	3	182	35
Professional fees	44	39	139	107
Interest (income) on accumulated cash	(16)	(5)	(39)	(18)
Other[(3)]	76	15	213	90
Total reorganization items	$ (3,940)	$ 146	$ (3,366)	$ 1,099

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(1) Represents our estimate of the expected allowed claims related primarily to guarantees of subsidiary obligations for the nine months ended September 30, 2006, the rejection or repudiation of leases and other executory contracts in both current and prior year periods and the effects of approved settlements during the three and nine months ended September 30, 2007. See further discussion below in "— Chapter 11 Claims Assessment."

(2) Impairment charges for the nine months ended September 30, 2007, primarily relate to recording our interest in Acadia PP at fair value less cost to sell. See Note 5 for additional information.

(3) Other reorganization items consist primarily of adjustments for foreign exchange rate changes on LSTC denominated in a foreign currency and governed by foreign law and employee severance and incentive costs in all periods.

Chapter 11 Claims Assessment

The U.S. Bankruptcy Court established August 1, 2006, as the bar date for filing proofs of claim against the U.S. Debtors' estates, other than claims against Calpine Geysers Company, L.P., as to which the bar date was October 31, 2006, and Santa Rosa Energy Center LLC, as to which the bar date was November 5, 2007. Under certain limited circumstances, some creditors will be permitted to file claims after the applicable bar dates. Accordingly, it is possible that not all potential claims were filed as of the filing of this Report. The differences between amounts recorded by the U.S. Debtors and proofs of claim filed by the creditors are investigated and resolved through the claims reconciliation process. Because of the number of creditors and claims, the claims reconciliation process may take considerable time to complete and we expect will continue after our emergence from Chapter 11.

Notwithstanding the foregoing, we have recognized certain charges related to allowed claims or expected allowed claims. The U.S. Bankruptcy Court will ultimately determine liability amounts that will be allowed for claims. As claims are resolved, or where better information becomes available and is evaluated, we will make adjustments to the liabilities recorded on our Consolidated Condensed Financial Statements as appropriate. Any such adjustments could be material to our financial position or results of operations in any given period.

Liabilities Subject to Compromise — The amounts of LSTC at September 30, 2007, and December 31, 2006, consisted of the following (in millions):

	September 30, 2007	December 31, 2006
Provision for expected allowed claims[1]	$ 3,626	$ 5,921
Second Priority Debt[2]	3,672	3,672
Unsecured senior notes	1,880	1,880
Convertible Notes	1,824	1,824
Notes payable and other liabilities — related party	261	1,077
Accounts payable and accrued liabilities	404	383
Total liabilities subject to compromise	$ 11,667	$ 14,757

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(1) The remaining balance in the provision for expected allowed claims at September 30, 2007, represents our allowed or expected allowed claims (at current exchange rates) for U.S. Debtor guarantees of debt issued by certain of our deconsolidated Canadian entities, expected allowed claims related to the rejection or repudiation of leases and other executory contracts and the results of other approved settlements. The provision for expected allowed claims was adjusted during the three months ended September 30, 2007, to record the effects of the Canadian Settlement Agreement described below.

(2) As our total enterprise value upon emergence has not been finally determined, we have not yet concluded whether our Second Priority Debt is fully secured or undersecured. We do, however, believe that there is uncertainty about whether the market value of the assets collateralizing the obligations owing in respect of the Second Priority Debt is less than, equals or exceeds the amount of these obligations. Therefore, in accordance with the applicable accounting standards, we have classified the Second Priority Debt as LSTC.

Canadian Settlement Agreement — On July 30, 2007, we entered into the Canadian Settlement Agreement after the Bankruptcy Courts approved the terms of our two previously disclosed proposed settlements with the Canadian Debtors and with an ad hoc committee of holders of notes issued by our subsidiary ULC I and guaranteed by Calpine Corporation. The Canadian Settlement Agreement, which encompasses both proposed settlements, resolves virtually all major cross-border issues among the parties relating to pre-petition intercompany balances, our direct and indirect guarantees of the ULC I notes and our guarantee of the ULC II notes and related interest. The material contingencies within the Canadian Settlement Agreement were resolved by September 30, 2007. As a result, the provision for expected allowed claims in reorganization items was reduced by approximately $4.1 billion and interest expense was increased by approximately $0.3 billion on our Consolidated Condensed Statements of Operations during the three months ended September 30, 2007.

Second Priority Debt Settlement Agreement — On August 8, 2007, the U.S. Bankruptcy Court approved a settlement with the Ad Hoc Committee of Second Lien Holders of Calpine Corporation and Wilmington Trust Company as indenture trustee for the Second Priority Notes. Pursuant to the settlement, approximately $289 million of claims for make whole premiums and/or damages asserted against the U.S. Debtors by the holders of the Second Priority Debt will be replaced by a secured claim for $60 million that shall be paid in cash and an unsecured claim for $40 million. As a result, we recorded expense of $100 million to the provision for expected allowed claims in reorganization items on our Consolidated Condensed Statements of Operations during the three months ended September 30, 2007.

Convertible Notes — On August 10, 2007, the U.S. Bankruptcy Court approved our limited objection to certain claims asserted by holders of the Convertible Notes, disallowing claims seeking damages for alleged breach of "conversion rights." The U.S. Bankruptcy Court's decision does not affect a previous agreement to allow claims for repayment of principal and interest on the Convertible Notes.

Unsecured Notes Settlement Agreement — On October 10, 2007, the U.S. Bankruptcy Court approved the settlement agreement with the Unsecured Noteholders and the indenture trustee for such Unsecured Notes. Under the agreement, $109 million of claims for make whole premiums asserted against the U.S. Debtors were replaced with unsecured claims totaling $54 million. In addition, the U.S. Debtors have agreed to pay the reasonable professional fees incurred by the Unsecured Noteholders and the indenture trustee. As a result, we recorded expense of $54 million to the provision for expected allowed claims in reorganization items on our Consolidated Condensed Statements of Operations during the three months ended September 30, 2007.

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

As of September 30, 2007, and December 31, 2006, the components of property, plant and equipment were stated at cost less accumulated depreciation as follows (in millions):

	September 30, 2007	December 31, 2006
Buildings, machinery and equipment	$ 13,520	$ 13,993
Geothermal properties	935	934
Other	249	272
	14,704	15,199
Less: Accumulated depreciation	(2,481)	(2,253)
	12,223	12,946
Land	78	85
Construction in progress	151	572
Property, plant and equipment, net	$ 12,452	$ 13,603

Construction in Progress — In April 2007, the Freeport Energy Center in Freeport, Texas began commercial operations. Accordingly, the power plant's construction in progress costs were transferred to the applicable property category, primarily buildings, machinery and equipment. See also Note 1 for a discussion of the impact of the deconsolidation of OMEC and Note 5 for a discussion of the construction projects classified as assets held for sale.

4. Investments

At September 30, 2007, and December 31, 2006, our joint venture and other equity investments included the following (in millions):

	Ownership Interest as of September 30, 2007	Investment Balance at September 30, 2007	Investment Balance at December 31, 2006
Greenfield LP	50%	$ 90	$ 129
OMEC	100%	159	—
Total investments in power projects		$ 249	$ 129

Greenfield Energy Centre 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 LIBOR plus 1.2% or prime rate plus 0.2%.

During the three and nine months ended September 30, 2007, we contributed nil and $68 million, respectively, as an additional investment in Greenfield LP. In connection with obtaining the project financing in May 2007, for the three and nine months ended September 30, 2007, we received cash of $12 million and $104 million, respectively, from Greenfield LP as a return of our investment.

Otay Mesa Energy Center, LLC — 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. 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%.

Other — We also hold a 100% interest in certain Canadian and other foreign subsidiaries most of which were deconsolidated as of the Petition Date, due to filings by certain of the Canadian subsidiaries for creditor protection under the CCAA in Canada. All of these investments were fully impaired as of the Petition Date, and are accounted for under the cost method.

5. Asset Sales

On January 16, 2007, we completed the sale of the Aries Power Plant, a 590-MW natural gas-fired power plant in Pleasant Hill, Missouri, to Dogwood Energy LLC, an affiliate of Kelson Holdings, LLC, for $234 million, plus certain per diem expenses incurred by us for running the power plant after December 21, 2006, through the closing of the sale. We recorded a pre-tax gain of approximately $78 million during the first quarter of 2007. As part of the sale we were also required to use a portion of the proceeds received to repay approximately $159 million principal amount of financing obligations, $8 million in accrued interest, $11 million in accrued swap liabilities and $14 million in debt pre-payment and make whole premium fees to our project lenders.

On February 21, 2007, we completed the sale of substantially all of the assets of the Goldendale Energy Center, a 247-MW natural gas-fired power plant located in Goldendale, Washington, to Puget Sound Energy LLC for approximately $120 million, plus the assumption by Puget Sound of certain liabilities. We recorded a pre-tax gain of approximately $31 million during the first quarter of 2007.

On March 22, 2007, we completed the sale of substantially all of the assets of PSM, a designer, manufacturer and marketer of turbine and combustion components, to Alstom Power Inc. for approximately $242 million, plus the assumption by Alstom Power Inc. of certain liabilities. In connection with the sale, we entered into a parts supply and development agreement with PSM whereby we have committed to purchase turbine parts and other services totaling approximately $200 million over a five-year period. Additionally, we recorded a pre-tax gain of $135 million during the first quarter of 2007 as the risks and other incidents of ownership were transferred to Alstom Power Inc.

On July 6, 2007, we completed the sale of the Parlin Power Plant, a 118-MW natural gas-fired power plant in Parlin, New Jersey, to EFS Parlin Holdings, LLC, an affiliate of General Electric Capital Corporation, for approximately $3 million in cash, plus the assumption by EFS Parlin Holdings, LLC of certain liabilities and the agreement to waive certain asserted claims against the Parlin Power Plant. We recorded a pre-tax gain of approximately $40 million during the three months ended September 30, 2007.

On September 13, 2007, we completed the sale of our 50% ownership interest in Acadia PP, the owner of the Acadia Energy Center, a 1,212-MW natural gas-fired power plant located near Eunice, Louisiana, to Cajun Gas Energy, L.L.C. for consideration totaling approximately $189 million consisting of $104 million in cash and the payment of $85 million in priority distributions due to Cleco (the indirect owner, through its subsidiary APH, of the remaining 50% ownership interest in Acadia PP) in accordance with the limited liability company agreement, plus the assumption by Cajun Gas Energy, L.L.C. of certain liabilities. We recorded a pre-tax loss of $6 million during the three months ended September 30, 2007, after having recorded a pre-tax, predominately non-cash impairment charge of approximately $89 million during the second quarter of 2007, to record our interest in Acadia PP at fair value less cost to sell, both of which charges are included in reorganization items on our Consolidated Condensed Statements of Operations. Additionally, in connection with the sale, we entered into a settlement agreement with Cleco, which was approved by the U.S. Bankruptcy Court on May 9, 2007, under which Cleco received an allowed unsecured claim against us in the amount of $85 million as a result of the rejection by CES of two long-term PPAs for the output of the Acadia Energy Center and our guarantee of those agreements. We recorded expense of $85 million for this allowed claim during the second quarter of 2007, which is included in reorganization items on our Consolidated Condensed Statements of Operations.

The sales of the Aries Power Plant, the Goldendale Energy Center, the Parlin Power Plant and our interest in Acadia PP discussed above did not meet the criteria for discontinued operations due to our continuing activity in the markets in which these power plants operate; therefore, the results of operations for all periods prior to sale are included in our continuing operations. Similarly, we have determined that the sale of PSM does not meet the criteria for discontinued operations due to our continuing involvement through the parts supply and development agreement; therefore, the results of operations for all periods prior to sale are included in our continuing operations.

Assets Held for Sale — We are actively marketing two projects for which construction was suspended in 2005 due to our Chapter 11 filings. As a result, our assets held for sale consist of construction in progress of $198 million at September 30, 2007.

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 investee's OCI, and the effects of foreign currency translation adjustments. We report AOCI on our Consolidated Condensed Balance Sheets. The table below details the components of our comprehensive income (loss) during the three and nine months ended September 30, 2007 and 2006 (in millions).

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Net income (loss)	$ 3,794	$ 2	$ 2,835	$ (1,405)
Other comprehensive income (loss):				
Comprehensive pre-tax gain (loss) on cash flow hedges before reclassification adjustment	(51)	(30)	(56)	43
Reclassification adjustment for (gains) losses included in net income (loss)	(12)	93	17	104
Foreign currency translation loss	(4)	—	(15)	(2)
Income tax provision	(4)	(20)	(13)	(53)
Total comprehensive income (loss)	$ 3,723	$ 45	$ 2,768	$ (1,313)

7. Debt

Long-term debt at September 30, 2007, and December 31, 2006, was as follows (in millions):

	September 30 2007	December 31, 2006
DIP Facility	$ 3,980	$ —
Original DIP Facility	—	997
CalGen financing	—	2,511
Construction/project financing	1,953	2,203
CCFC financing	779	782
Preferred interests	575	584
Notes payable and other borrowings	433	564
Capital lease obligations	284	280
Total debt (not subject to compromise)	8,004	7,921
Less: Amounts reclassified to debt, current portion	677	3,051
Less: Current maturities	4,198	1,518
Debt (not subject to compromise), net of current portion	$ 3,129	$ 3,352

DIP Facility — On March 29, 2007, we completed the refinancing of the Original DIP Facility with our $5.0 billion DIP Facility. The DIP Facility consists 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 permits us to raise up to $2.0 billion of incremental term loan funding on a senior secured basis with the same priority as the current debt under the DIP Facility. The DIP Facility is priced at LIBOR plus 2.25% or base rate plus 1.25% and matures on the earlier of the effective date of a confirmed plan or plans of reorganization or March 29, 2009. We have the option to convert the DIP Facility into our exit financing, provided certain conditions are met, which would extend the maturity date to March 29, 2014. We expect the effective date of our Plan of Reorganization will be within the next twelve months; therefore, borrowings under the DIP Facility are classified as current at September 30, 2007. In addition to refinancing the Original DIP Facility, borrowings under the DIP Facility were applied on March 29, 2007, to the repayment of the approximately $2.5 billion outstanding principal amount of CalGen Secured Debt (see "— Repayment of CalGen Secured Debt" below). In connection with the refinancing of our Original DIP Facility, we incurred transaction costs of $52 million which are included in reorganization items on our Consolidated Condensed Statements of Operations.

On July 11, 2007, the U.S. Bankruptcy Court authorized us to enter into a commitment letter to fund additional credit facilities, pay associated commitment and other fees, and to amend the DIP Facility to provide for additional secured exit financing of up to $3.0 billion in addition to amounts currently available under the DIP Facility upon conversion of the DIP Facility to exit financing, for a total of $8.0 billion. The amendment of the DIP Facility is subject to further conditions, including obtaining necessary approvals of lenders under the DIP Facility. The commitment to fund the additional facilities under the amended DIP Facility will expire on January 31, 2008, if certain conditions, including effectiveness of the Plan of Reorganization, are not met. In connection with the commitment letter to fund this additional exit financing, we incurred transaction costs of $22 million which are included in reorganization items on our Consolidated Condensed Statements of Operations.

The DIP Facility contains restrictions on the U.S. Debtors, including limiting their ability to, among other things: (i) incur additional indebtedness; (ii) create or incur liens to secure debt; (iii) lease, transfer or sell assets or use proceeds of permitted asset leases, transfers or sales; (iv) issue capital stock; (v) make investments; and (vi) conduct certain types of business.

Our ability to utilize the DIP Facility is subject to the DIP Order. Subject to the exceptions set forth in the DIP Order, the obligations of the U.S. Debtors under the DIP Facility are an allowed administrative expense claim in each of the loan parties' Chapter 11 cases, and are collateralized by (i) a perfected first priority lien on, and security interest in, all present and after-acquired property of the U.S. Debtors not subject to a valid, perfected and non-avoidable lien in existence on the

Petition Date or to a valid lien in existence on the Petition Date and subsequently perfected (excluding rights in avoidance actions), (ii) a perfected junior lien on, and security interest in, all present and after-acquired property of the U.S. Debtors that is otherwise subject to a valid, perfected and non-avoidable lien in existence on the Petition Date or a valid lien in existence on the Petition Date that is subsequently perfected and (iii) to the extent applicable, a perfected first priority priming lien on, and security interest in, all present and after-acquired property of the U.S. Debtors that is subject to the replacement liens granted pursuant to and under the Cash Collateral Order.

As of September 30, 2007, there was $4.0 billion outstanding under the term loan facility, no borrowings outstanding under the revolving credit facility and $219 million of letters of credit issued against the revolving credit facility.

Repayment of CalGen Secured Debt — On March 29, 2007, we repaid the approximately $2.5 billion outstanding principal amount of CalGen Secured Debt, primarily with borrowings under the DIP Facility term loan facility plus approximately $224 million of cash on hand at CalGen. To effectuate the repayment of the CalGen Secured Debt, the U.S. Debtors requested that the U.S. Bankruptcy Court allow the U.S. Debtors' limited objection to claims filed by the holders of the CalGen Secured Debt. The U.S. Bankruptcy Court granted the U.S. Debtors' limited objection in part, finding that the CalGen Secured Debt lenders were not entitled to a secured claim for a pre-payment premium under the CalGen loan documents. However, the U.S. Bankruptcy Court granted the CalGen Secured Debt lenders an unsecured claim for damages. Specifically, the U.S. Bankruptcy Court held that (i) the holders of the CalGen First Lien Debt are entitled to an unsecured claim for damages in the amount of 2.5% of the outstanding principal, (ii) the holders of the CalGen Second Lien Debt are entitled to an unsecured claim for damages in the amount of 3.5% of the outstanding principal, and (iii) the holders of the CalGen Third Lien Debt are entitled to an unsecured claim for damages in the amount of 3.5% of the outstanding principal. As a result of the DIP Order and repayment of CalGen Secured Debt, we recorded expense of $32 million to write off the remaining unamortized discount and deferred financing costs and recorded $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. These expenses are included in reorganization items on our Consolidated Condensed Statements of Operations for the nine months ended September 30, 2007. Both we and the holders of the CalGen Secured Debt have appealed the DIP Order to the SDNY Court. In this appeal, the holders of the CalGen Secured Debt are arguing for larger, secured damages claims and we are arguing that no damages should arise in connection with the repayment of the CalGen Secured Debt. We are seeking permission from the U.S. Bankruptcy Court to amend our Plan of Reorganization to pay the damages, if any, awarded to the holders of the CalGen Secured Debt in full and in cash or cash equivalents in the amount ultimately determined on appeal by a final order, regardless of whether such claims are deemed secured or remain unsecured. The holders of the CalGen Secured Debt are also seeking interest on their claims at the default rate. The U.S. Bankruptcy Court concluded that a decision on default interest was premature. Accordingly, we have not accrued any default interest for the CalGen Secured Debt as of September 30, 2007. Under the CalGen Secured Debt agreements, the lenders could receive additional default interest of 1% on the CalGen Notes and 2% on the CalGen Term Loans from December 21, 2005, through March 29, 2007.

Annual Debt Maturities

Contractual annual principal repayments or maturities of debt instruments not subject to compromise, as of September 30, 2007, are as follows (in millions):

October through December 2007	$ 28
2008	4,197
2009	600
2010	525
2011	1,822
Thereafter	866
Total debt	8,038
(Discount) Premium	(34)
Total	$ 8,004

Debt, Lease and Indenture Covenant Compliance

Our filings under Chapter 11 and the CCAA constituted events of default or otherwise triggered repayment obligations under the instruments governing substantially all of the indebtedness of the Calpine Debtors outstanding at the Petition Date. As a result of the events of default, the debt outstanding under the affected debt instruments generally became automatically and immediately due and payable. We believe that any efforts to enforce such payment obligations against U.S. Debtors are stayed as a result of the Chapter 11 filings and subject to our Chapter 11 cases. Although the CCAA does not provide an automatic stay, the Canadian Court has granted a stay to the Canadian Debtors that currently extends through December 20, 2007. Such events of default generally also constituted breaches of executory contracts and unexpired leases of U.S. Debtors. Actions taken by counterparties or lessors based on such breaches, we believe, are also stayed as a result of the Chapter 11 filings. However, under the Bankruptcy Code, we must cure all pre-petition defaults of executory contracts and unexpired leases that we seek to assume. Once we assume an executory contract or unexpired lease pursuant to an order of the U.S. Bankruptcy Court, such executory contract or unexpired lease becomes a post-petition obligation of the applicable U.S. Debtor, and efforts on the part of counterparties or lessors to enforce the U.S. Debtor's obligations under such contracts or leases may or may not be stayed as a result of the Chapter 11 filings.

In addition, as described further below, the Chapter 11 filings by certain of the U.S. Debtors caused, directly or indirectly, defaults or events of default under the debt of certain Non-Debtor entities. Such events of default (or defaults that become events of default) could give holders of debt under the relevant instruments the right to accelerate the maturity of all debt outstanding thereunder if the defaults or events of default were not cured or waived. There can be no assurance that such waivers can be obtained or defaults otherwise cured.

Calpine Debtor Entities

Pursuant to the DIP Facility, we are subject to a number of affirmative and restrictive covenants, reporting requirements and financial covenants which are customary for DIP financings of this nature. As of September 30, 2007, we were in compliance with the DIP Facility covenants.

In addition to the events of default caused as a result of our Chapter 11 or CCAA filings, we may not be in compliance with certain other covenants under the indentures or other debt or lease instruments of certain Calpine Debtor entities, the obligations under all of which have been accelerated as discussed above.

Non-Debtor Entities

As of September 30, 2007, we were in compliance with our obligations under the instruments governing the debt of our Non-Debtor entities, except as described below.

Blue Spruce Energy Center. In connection with the project financing transaction by Blue Spruce, an event of default existed under the project credit agreement, due to cross default provisions related to the Chapter 11 filing by CES. Subsequently, we obtained an amendment and waiver under the project credit agreement from the lender, which waived the event of default unless and until the CES tolling agreement related to the Blue Spruce power plant is rejected in the Chapter 11 cases. In addition, we have failed to deliver certain financial information for this project within the times provided under the project credit agreement. Accordingly, our obligations under this financing have been classified as current.

Calpine King City Cogen. In connection with the sale/leaseback transaction at the King City Power Plant, the Chapter 11 filings by certain affiliates of King City Cogen constituted an event of default under the lease agreement. We have obtained a forbearance agreement that is in effect until January 1, 2008. As a result of the expiration date of the forbearance agreement, our obligations under this financing have been classified as current.

Pasadena Power Plant. In connection with our Pasadena lease financing transaction, our Chapter 11 filings constituted an event of default under Pasadena's participation agreement and certain other agreements relating to the transaction, which resulted in events of default under the indenture governing certain notes issued by the Pasadena ownerlessor. We entered into a forbearance agreement with the holders of a majority of the outstanding notes pursuant to which the noteholders have agreed to forbear from taking any action with respect to the events of default. Such forbearance agreement has lapsed and there is currently no forbearance agreement in place. In addition, we allowed the incurrence and existence of certain liens, permitted certain prohibited intercompany arrangements, failed to obtain certain insurance waivers, transferred beneficial interests in certain Calpine subsidiaries and experienced other defaults. As a result, our obligations with respect to this lease financing have been classified as current.

8. Derivative Instruments

The table below reflects the amounts that are recorded as assets and liabilities at September 30, 2007, for our derivative instruments (in millions):

	Interest Rate Derivative Instruments	Commodity Derivative Instruments Net	Total Derivative Instruments
Current derivative assets	$ 2	$ 225	$ 227
Long-term derivative assets	—	257	257
Total assets	$ 2	$ 482	$ 484
Current derivative liabilities	$ 18	$ 262	$ 280
Long-term derivative liabilities	39	390	429
Total liabilities	$ 57	$ 652	$ 709
Net derivative assets (liabilities)	$ (55)	$ (170)	$ (225)

Of our net derivative liabilities at September 30, 2007, $53 million are net derivative assets of PCF, which is an entity with its existence separate from us and other subsidiaries of ours, and $94 million are net derivative liabilities of Deer Park. We fully consolidate Deer Park and PCF. As a result, we present the assets and liabilities of these entities on our Consolidated Condensed Balance Sheets.

During the nine months ended September 30, 2007, we entered into several interest rate swaps to reduce the risk of unfavorable changes in variable interest rates related to changes in LIBOR associated with both existing and anticipated debt issuances. These swaps have an aggregate notional amount of $5.0 billion and range in maturity through September 2012. At September 30, 2007, the fair value of these swaps of $(51) million is included in our net derivative liabilities.

Below is a reconciliation of our net derivative liabilities to our accumulated other comprehensive loss, net of tax from derivative instruments at September 30, 2007 (in millions):

	September 30, 2007
Net derivative liabilities	$ (225)
Derivatives not designated as cash flow hedges and recognized hedge ineffectiveness	131
Cash flow hedges terminated prior to maturity	(14)
Cumulative OCI tax benefit	12
Accumulated other comprehensive loss from derivative instruments, net of tax[1]	$ (96)

(1) Amount represents one portion of our total AOCI balance of $(113).

Mark-to-market activities, net as shown on our Consolidated Condensed Statements of Operations includes realized settlements of and unrealized mark-to-market gains and losses on both power and gas derivative instruments not designated as cash flow hedges. Gains (losses) due to ineffectiveness on hedging instruments were nil and $1 million for the three months ended September 30, 2007 and 2006, respectively, and $1 million and $(2) million for the nine months ended September 30, 2007 and 2006, respectively. Hedge ineffectiveness is included in unrealized mark-to-market gains and losses.

The table below reflects the contribution of our cash flow hedge activity to pre-tax earnings based on the reclassification adjustment from AOCI to earnings for the three and nine months ended September 30, 2007 and 2006, respectively (in millions):

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
Natural gas derivatives	$ (77)	$ 43	$ (92)	$ 227
Power derivatives	89	(135)	85	(325)
Interest rate derivatives	—	(1)	(10)	(6)
Total derivatives	$ 12	$ (93)	$ (17)	$ (104)

As of September 30, 2007, the maximum length of time over which we were hedging our exposure to the variability in future cash flows for forecasted transactions was 6 years for both commodity and interest rate derivative instruments. We currently estimate that pre-tax gains of $22 million would be reclassified from AOCI into earnings during the twelve months ended September 30, 2008, 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 the probability that gas and power prices as well as interest rates will, in fact, change. 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).

	2007	2008	2009	2010	2011	Thereafter	Total
Natural gas derivatives	$ (48)	$ (27)	$ 1	$ (1)	$ (3)	$ (4)	$ (82)
Power derivatives	60	35	(24)	(15)	(9)	(6)	41
Interest rate derivatives	(3)	(20)	(26)	(9)	2	(11)	(67)
Total pre-tax AOCI	$ 9	$ (12)	$ (49)	$ (25)	$ (10)	$ (21)	$ (108)

9. Earnings (Loss) per Share

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(shares in thousands)			
Diluted weighted average shares calculation:				
Weighted average shares outstanding (basic)	479,312	479,136	479,208	479,136
Plus: Incremental shares from unexercised in-the-money stock options	305	—	335	—(1)
Weighted average shares outstanding (diluted)	479,617	479,136	479,543	479,136

(1) As we incurred net losses during the nine months ending September 30, 2006, diluted loss per share is computed on the same basis as basic loss per share as the inclusion of any other potential shares outstanding would be anti-dilutive.

We excluded the following items from diluted earnings (loss) per common share:

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(shares in thousands)			
Unexercised out-of-the-money stock options	16,944	24,889	18,585	30,159
Restricted stock awards[(1)]	500	709	553	797
Convertible Notes[(2)]	399,914	399,914	399,914	399,914
DB London shares[(3)]	2,427	64,000	2,427	64,000

(1) Excluded from diluted weighted average shares outstanding because our closing stock price had not reached the price at which the shares vest.

(2) Excluded from diluted weighted average shares outstanding because we believe the conversion rights were terminated upon our Chapter 11 filings. On August 10, 2007, the U.S. Bankruptcy Court disallowed the claims for conversion right damages by the holders of the Convertible Notes on the basis that, among other things, such conversion rights had terminated upon our Chapter 11 filings. Accordingly, we have excluded the Convertible Notes from diluted weighted average shares outstanding.

(3) Excluded from basic and diluted weighted average shares outstanding as the share lending agreement with DB London requires physical settlement of these common shares.

10. Commitments and Contingencies

We are party to various litigation matters arising out of the normal course of business, the more significant of which are summarized below. The ultimate outcome of each of these matters cannot presently be determined, nor can the liability that could potentially result from a negative outcome 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. Further, we and the majority of our subsidiaries filed either for reorganization under Chapter 11 in the U.S. Bankruptcy Court or creditor protection under the CCAA in the Canadian Court on the Petition Date, and additional subsidiaries have filed thereafter. Generally, pursuant to automatic stay provisions under the Bankruptcy Code and orders (which currently extend through December 20, 2007) granted by the Canadian Court, all actions to enforce or otherwise effect repayment of liabilities preceding the Petition Date as well as pending litigation against the Calpine Debtors are stayed while the Calpine Debtors continue their business operations as debtors-in-possession. Accordingly, unless indicated otherwise, each pre-petition litigation matter listed below is currently stayed. To the extent that there are any judgments against us in any of these matters during the pendency of our Chapter 11 cases, we expect that such judgments would be classified as LSTC. See Note 2 for information regarding our Chapter 11 cases and CCAA proceedings. In addition to the Chapter 11 cases and CCAA proceedings (in connection with which certain of the matters described below arose), and the other matters described below, we are involved in various other claims and legal actions 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 subsequently transferred 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, Banc of America Securities, Deutsche Bank Securities, and Goldman, Sachs & Co. The Hawaii Structural Ironworkers Pension Fund alleges that the prospectus and registration statement for the April 2002 offering contained false or misleading statements regarding: Calpine's actual financial results for 2000 and 2001; Calpine's projected financial results for 2002; Mr. Cartwright's agreement not to sell or purchase shares within 90 days of the April 2002 offering; and Calpine's alleged involvement in "wash trades." This action is stayed as to Calpine Corporation as a result of our Chapter 11 filing and to the individual defendants listed above by an order of the U.S. Bankruptcy Court, and to the underwriter defendants listed above by an order of the Superior Court. There is no trial date in this action. The parties attended a mediation in August 2007, which did not result in a settlement; however, the parties are discussing scheduling a second mediation in the future. We consider this lawsuit to be without merit and, should the case proceed against Calpine Corporation, 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 Appeals' 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 settlement is subject to definitive documentation and approval by the U.S. Bankruptcy Court and the Northern District Court.

Johnson v. Peter Cartwright, et al. On December 17, 2001, a shareholder filed a derivative lawsuit on behalf of Calpine Corporation against its directors and one of its senior officers. This lawsuit is styled *Johnson vs. Cartwright, et al.* (No. CV803872) and is pending, but stayed, in Santa Clara County Superior Court. Calpine Corporation is a nominal defendant in this lawsuit, which alleges claims relating to purportedly misleading statements about Calpine Corporation and stock sales by certain of the director defendants and the officer defendant. On July 1, 2003, the Santa Clara County Superior Court granted Calpine Corporation's motion to stay this proceeding until *In re Calpine Corporation Securities Litigation*, an action then-pending in the Northern District of California, was resolved, or until its further order. *In re Calpine Corporation Securities Litigation* was resolved by a settlement in November 2005. This case is stayed as to Calpine Corporation as a result of our Chapter 11 filing. In addition, Calpine Corporation filed a motion with the U.S. Bankruptcy Court to extend the automatic stay to the individual defendants and plaintiff opposed the motion. On June 5, 2006, the motion was granted by the U.S. Bankruptcy Court extending the stay to the individual defendants and ruling that plaintiff has no standing to pursue derivative claims. Calpine Corporation objected to the claim against it, and that claim has been expunged by order of the U.S. Bankruptcy Court. The case remains stayed as to Calpine Corporation and the individual defendants. We consider this lawsuit to be without merit and, should the case proceed against Calpine Corporation, intend to continue to defend vigorously against the allegations if the stay is lifted.

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 on December 1, 2003, under a promissory note on which approximately $51 million (including related interest) was outstanding at September 30, 2007. Calpine has filed a counterclaim against Panda and related parties based on a guaranty and loan agreement. Defendants have also been successful in dismissing the causes of action alleged by Panda for federal and state securities laws violations. We consider Panda's lawsuit to be without merit and intend to continue to vigorously defend it. Calpine stopped accruing interest income on the promissory note due December 1, 2003, as of the due date because of Panda's default on repayment of the note. Trial was set for May 22, 2006, but did not proceed due to the stay. Calpine filed a motion to lift the automatic stay to pursue our counterclaim on October 3, 2007. The motion is currently scheduled for hearing on November 14, 2007.

Snohomish PUD No. 1, et al. v. FERC (regarding Nevada Power Company and Sierra Pacific Power Company v. Calpine Energy Services, L.P. complaint dismissed by FERC). On December 4, 2001, NPC and SPPC filed a complaint with FERC under Section 206 of the FPA against a number of parties to their PPAs, including CES. NPC and SPPC allege in their complaint that the prices they agreed to pay in certain of the PPAs, including those signed with CES, were negotiated during a time when the spot power market was dysfunctional and that they are unjust and unreasonable. The complaint therefore sought modification of the contract prices. The administrative law judge issued an Initial Decision on December 19, 2002, that found for CES and the other respondents in the case and denied NPC and SPPC the relief that they were seeking. In a June 26, 2003 order, FERC affirmed the judge's findings and dismissed the complaint, and subsequently denied rehearing of that order. The case was appealed to the Ninth Circuit Court of Appeals. On December 19, 2006, the Ninth Circuit Court of Appeals issued a decision finding that FERC erred in its legal analysis and remanded the cases to FERC for further review. CES, along with other suppliers, filed a Petition for Certiorari with the U.S. Supreme Court on May 3, 2007, asking the Court to review the Ninth Circuit Court of Appeals' decision. Several additional Petitions for Certiorari were filed by other power suppliers affected by the Ninth Circuit Court of Appeals' decision. The U.S. Supreme Court granted Certiorari on September 25, 2007. However, Calpine, NPC and SPPC have settled the dispute pursuant to a settlement agreement discussed in *Transmission Service Agreement with Nevada Power Company* below. In addition, NPC and SPPC filed a motion at FERC on September 28, 2007, to withdraw with prejudice their original complaint and are seeking approval of the settlement agreement. The effectiveness of the settlement agreement approved by the U.S. Bankruptcy Court is not subject to FERC approval.

Transmission Service Agreement with Nevada Power Company. On September 30, 2004, NPC filed a complaint in state district court of Clark County, Nevada against Calpine Corporation, Moapa, FFIC and unnamed parties alleging, among other things, breach by Calpine Corporation of its obligations under a TSA between Calpine Corporation and NPC for 400 MW of transmission capacity and breach by FFIC of its obligations under a surety bond, which surety bond was issued by FFIC to NPC to support Calpine Corporation's obligations under this TSA. This proceeding was removed from state court to the U.S. District Court for the District of Nevada. On December 10, 2004, FFIC filed a motion to dismiss, which was granted on May 25, 2005 with respect to claims asserted by NPC that FFIC had breached its obligations under the surety bond by not honoring NPC's demand that the full amount of the surety bond ($33 million) be paid to NPC in light of Calpine Corporation's failure to provide replacement collateral upon the expiration of the surety bond on May 1, 2004. NPC's motion to amend the complaint was granted on November 17, 2005 and its amended complaint was filed December 8, 2005. This case was stayed as to Calpine Corporation and Moapa on the Petition Date, but not as to co-defendant FFIC. On February 10, 2006, FFIC filed a motion to dismiss NPC's amended complaint for failure to state a claim against FFIC. On June 1, 2006, the district court issued an order denying FFIC's motion. FFIC answered the amended complaint on June 16, 2006. On August 1, 2006, the U.S. Debtors filed an adversary complaint and motion against NPC seeking an extension of the automatic stay, or in the alternative, a temporary injunction to preclude NPC from pursuing its derivative claims against FFIC while the U.S. Debtors restructured. On August 16, 2006, NPC agreed to take no further action in the Nevada district court litigation until the U.S. Bankruptcy Court ruled on the U.S. Debtors' motion. The Creditors' Committee and FFIC filed motions to intervene in the adversary proceeding, which were granted on October 25, 2006. Also on October 25, 2006, the U.S. Bankruptcy Court granted the U.S. Debtors' motion, enjoining prosecution of the NPC action until after the successful implementation of a plan or plans of reorganization or further order of the U.S. Bankruptcy Court. On November 1, 2006, NPC filed a notice of appeal of the U.S. Bankruptcy Court's decision enjoining prosecution of the NPC action. On March 28, 2007, the SDNY Court issued an opinion and order affirming the U.S. Bankruptcy Court's stay orders. The appeal to the SDNY Court was subsequently dismissed. On April 25, 2007, NPC filed a Notice of Appeal to the SDNY Court appealing the March 28, 2007 order. The appeal was subsequently dismissed. Calpine, NPC and SPPC entered into a settlement agreement dated September 18, 2007, resolving all claims under this case and the case entitled *Snohomish PUD No. 1, et al. v. FERC (regarding Nevada Power Company and Sierra Pacific Power Company v. Calpine Energy Services, L.P. complaint dismissed by FERC),* including providing NPC a release of claims against FFIC, and allowing general unsecured claims totaling $21 million. The settlement agreement was approved by the U.S. Bankruptcy Court on October 10, 2007. As a result, we recorded additional expense of $19 million in reorganization items on our Consolidated Condensed Statements of Operations during the three months ended September 30, 2007.

Harbert Distressed Investment Master Fund, Ltd. v. Calpine Canada Energy Finance II ULC, et al. On May 5, 2005, the Harbert Distressed Fund filed an application in the Supreme Court of Nova Scotia against Calpine Corporation and certain of its subsidiaries, including ULC II, the issuer of certain senior notes held by the Harbert Distressed Fund, and CCRC, the parent company of ULC II. Calpine Corporation has guaranteed the ULC II senior notes. In June 2005, the ULC II senior notes indenture trustee joined the application as co-applicant on behalf of all holders of the ULC II senior notes. The Harbert Distressed Fund and the ULC II senior notes indenture trustee alleged that Calpine Corporation, CCRC and ULC II violated the Harbert Distressed Fund's rights under Nova Scotia laws in connection with certain financing transactions completed by CCRC or subsidiaries of CCRC.

On August 2, 2005, the Supreme Court of Nova Scotia denied all relief to the Harbert Distressed Fund and all other holders of the ULC II senior notes that purchased ULC II senior notes on or after September 1, 2004. However, the Supreme Court of Nova Scotia did state that a remedy should be granted to any holder of ULC II senior notes, other than the Calpine respondent companies, that purchased ULC II senior notes prior to September 1, 2004, and that continued to hold those ULC II senior notes on August 2, 2005, and in connection therewith ordered CCRC to maintain control of the net proceeds from the July 2005 sale of the Saltend Energy Centre until a final order was issued. On November 30, 2005, the ULC II senior notes indenture trustee filed a final report confirming the aggregate face value of bonds held by holders of the ULC II senior notes that purchased such ULC II senior notes prior to September 30, 2004, and that continued to hold those ULC II senior notes on August 2, 2005, was (at then-current exchange rates) approximately $42 million.

On December 19 and 20, 2005, the parties reappeared before the Supreme Court of Nova Scotia to settle the terms of the final order. After argument, and to enable the parties to address an application by the ULC II senior notes indenture trustee to produce further information and documentation, this application was adjourned to January 12, 2006. On the Petition Date, in addition to Calpine's Chapter 11 filing, the Canadian Debtors, including ULC II and CCRC instituted the CCAA proceedings before the Canadian Court. As a result of the Chapter 11 cases and CCAA proceedings, all Canadian legal proceedings are stayed, and in particular the application to settle the final order in the application has been adjourned indefinitely.

In connection with the CCAA proceedings, Calpine Corporation had given undertakings to the Canadian Court and to the ULC II senior notes indenture trustee that: (i) the net Saltend Energy Centre sale proceeds remained at Calpine UK Holdings Limited, a subsidiary of CCRC; (ii) Calpine Corporation intended to continue to hold the monies there and would provide advance notice to the ULC II senior notes indenture trustee and the service list in the CCAA proceedings if that intention changed; (iii) the Saltend Energy Centre sale proceeds held at Calpine UK Holdings Limited were not pledged as collateral for the DIP Facility; and (iv) Calpine Corporation would provide advance notice to the ULC II senior notes indenture trustee and the service list in the CCAA proceedings of any filing of Calpine UK Holdings Limited in Canada, the U.S. or the United Kingdom. On July 31, 2006, consistent with the undertakings given to the Canadian Court and the order entered by the Supreme Court of Nova Scotia dated August 2, 2005, the Canadian Debtors gave notice that the net proceeds of the Saltend Energy Centre sale were being (and now have been) repatriated to Canadian Debtor CCRC.

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 allege 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. At a court hearing on November 22, 2005, counsel for Harbert Convertible Fund and the 2014 Convertible Notes trustee sought an expedited trial, stating that plaintiffs were willing to forego affirmative discovery and could respond to Calpine Corporation's forthcoming discovery requests promptly. The New York County Supreme Court ordered Harbert Convertible Fund and the 2014 Convertible Notes trustee to provide specified discovery immediately, to respond promptly to any additional discovery demands from Calpine Corporation, and ordered the parties to commence depositions in January 2006. The New York County Supreme Court did not set a firm trial date, but suggested that a trial could occur by early March 2006. Calpine Corporation moved to dismiss the second amended complaint on December 13, 2005. In the meantime, Harbert Convertible Fund and the 2014 Convertible Notes trustee delayed providing any discovery, stating their belief that a bankruptcy filing was imminent that could moot the case or in any event stay it. There has been no activity since the Petition Date.

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. There has been no activity since the Petition Date.

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 when granting the lease extensions and, therefore, held that the extensions were invalid. We are currently reviewing the order and considering our alternatives. 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 is stayed, but we are in communication with the U.S. Department of Justice regarding the possible remedies which could be argued to the District Court.

Post-Petition Litigation

Chapter 11 Related Litigation

Appeal Related to Rejection of Power Purchase Agreements. On December 21, 2005, we filed a motion with the U.S. Bankruptcy Court to reject eight PPAs and to enjoin FERC from asserting jurisdiction over the rejections. The U.S. Bankruptcy Court issued a temporary restraining order against FERC and set the matter for a hearing on January 5, 2006. Under most of the PPAs sought to be rejected, we are obligated to sell power at prices that are significantly lower than currently prevailing market prices. On December 29, 2005, certain counterparties to the various PPAs filed an action in the SDNY Court arguing that the U.S. Bankruptcy Court did not have jurisdiction over the dispute. On January 5, 2006, the SDNY Court entered an order that had the effect of transferring our motion seeking to reject the eight PPAs and our related request for an injunction against FERC to the SDNY Court from the U.S. Bankruptcy Court. Earlier, however, on December 19, 2005, CDWR, a counterparty to one of the eight PPAs, had filed a complaint with FERC seeking to obtain injunctive relief to prevent us from rejecting our PPA with CDWR and contending that FERC had exclusive jurisdiction over the matter. On January 3, 2006, FERC determined that it did not have exclusive jurisdiction, and that the matter could be heard by the U.S. Bankruptcy Court. However, despite the FERC ruling, on January 27, 2006, the SDNY Court determined that FERC had jurisdiction over whether the contracts could be rejected. We appealed the SDNY Court’s decision to the U.S. Court of Appeals for the Second Circuit. The appeal was heard on April 10, 2006. Prior to receiving a decision on the appeal, three of the PPAs were terminated by the applicable counterparties and the remaining five PPAs are the subject of negotiated settlements. Accordingly, on June 11, 2007, we sent a letter to the Court of Appeals for the Second Circuit informing the Court that all of the PPA disputes had been resolved and that we withdrew the appeal.

First Priority Notes Make Whole Litigation. In June 2006, pursuant to orders of the U.S. Bankruptcy Court, we completed repayment of the First Priority Notes at par ($646 million) plus accrued and unpaid interest. The repayment orders provided that such repayment was without prejudice to the rights of the holders of the First Priority Notes to pursue their demand for payment of a “make whole” premium they alleged to be due as a result of our repayment of First Priority Notes prior to their stated maturity. The First Priority Trustee appealed each of the repayment orders to the SDNY Court. In addition, the First Priority Trustee filed an adversary proceeding in the U.S. Bankruptcy Court on behalf of the holders of the First Priority Notes seeking a declaratory judgment on the merits of their demand for a “make whole” premium. On June 21, 2006, the U.S. Bankruptcy Court entered an order approving our request to extend the date by which we were required to answer or otherwise move with respect to the First Priority Trustee’s adversary proceeding until ten days after a final order was entered in the First Priority Trustee’s appeal to the SDNY Court of the repayment orders. The First Priority Trustee then appealed the U.S. Bankruptcy Court’s June 21, 2006, order to the SDNY Court as well, and on July 24, 2006, the SDNY Court entered an order consolidating both appeals. On January 9, 2007, the SDNY Court affirmed the U.S. Bankruptcy Court’s repayment orders, and dismissed for lack of appellate jurisdiction the First Priority Trustee’s appeal of the U.S. Bankruptcy Court’s June 21, 2006, order. On February 8, 2007, the First Priority Trustee filed a notice of appeal of the SDNY Court’s opinion to the Second Circuit Court of Appeals. On April 20, 2007, the Second Circuit Court of Appeals approved the parties’ stipulation to dismiss the First Priority Trustee’s appeals. The First Priority Trustee’s adversary proceeding remains pending in the U.S. Bankruptcy Court. On May 21, 2007, we filed an answer to the First Priority Trustee’s complaint in the adversary proceeding. That same day, the Creditors’ Committee filed an answer and counterclaim against the First Priority Trustee, the collateral trustee for the First Priority Notes, and the holders of the First Priority Notes. This counterclaim alleged that the First Priority Notes were not “Priority Lien” or “Secured Debt” under the terms of the applicable collateral trust agreement. The First Priority Trustee moved to dismiss the Creditors’ Committee counterclaim on June 15, 2007, and the collateral trustee did the same on June 25, 2007. A day later, the U.S. Bankruptcy Court entered an order setting a briefing schedule for the First Priority Trustee’s and our respective motions for summary judgment on the merits of the First Priority Trustee’s demand for a “make whole” premium. All of these motions for summary judgment are fully briefed and the hearing on the motions for summary judgment is currently scheduled for November 27, 2007.

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 $400 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 10, 2007, Rosetta filed a motion to dismiss or, in the alternative, to stay the proceeding. We filed an objection to Rosetta's motion on September 24, 2007. The motion to dismiss was denied by the U.S. Bankruptcy Court on October 24, 2007. As such, the parties will proceed with the adversary proceeding.

Other Post-Petition Matters

Communications with the SEC — We have been contacted by and have had discussions with the staff of the SEC regarding our financial statements and internal controls over financial reporting. We are cooperating with the SEC staff and voluntarily complying with their requests. We have not been informed whether we are under investigation. Our management has informed the SEC staff that we believe our financial statements and periodic reports filed with the SEC are compliant with the rules and regulations of the SEC and GAAP.

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) the risks and uncertainties associated with our Chapter 11 cases and CCAA proceedings, including our ability to successfully reorganize and emerge from Chapter 11; (ii) our ability to implement our business plan; (iii) financial results that may be volatile and may not reflect historical trends; (iv) seasonal fluctuations of our results; (v) potential volatility in earnings associated with fluctuations in prices for commodities such as natural gas and power; (vi) our ability to manage liquidity needs and comply with covenants related to our existing financing obligations and anticipated exit financing; (vii) the direct or indirect effects on our business of our impaired credit including increased cash collateral requirements in connection with the use of commodity contracts; (viii) transportation of natural gas and transmission of electricity; (ix) the expiration or termination of our PPAs and the related results on revenues; (x) risks associated with the operation of power plants including unscheduled outages; (xi) 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; (xii) risks associated with power project development and construction activities; (xiii) our ability to attract, retain and motivate key employees; (xiv) our ability to attract and retain customers and counterparties; (xv) competition; (xvi) risks associated with marketing and selling power from plants in the evolving energy markets; (xvii) present and possible future claims, litigation and enforcement actions; (xviii) effects of the application of laws or regulations, including changes in laws or regulations or the interpretation thereof; and (xix) other risks identified in this Report and our 2006 Form 10-K. You should also carefully review other reports that we file with the SEC, including without limitation our 2006 Form 10-K. 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, 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, 50 West San Fernando Street, San Jose, California 95113, attention: Corporate Communications, telephone: (408) 995-5115. We will not send exhibits to the documents, unless the exhibits are specifically requested and you pay our fee for duplication and delivery.

Executive Overview

Our Business

We are a wholesale power company that operates and develops clean, reliable and cost-competitive power generation facilities primarily in the U.S. Our core business and primary source of revenue is the generation and sale of electricity and electricity-related products across the U.S. through the operation of our portfolio of generation assets. We protect and enhance the value of our assets with sophisticated commercial risk management and asset optimization, related to the dispatch and maintenance of our power plants. Since the Petition Date, we have been operating as debtors-in-possession pursuant to the Bankruptcy Code.

We operate a fleet of power generation facilities with nearly 24,000 MW of capacity as of September 30, 2007, making us one of the largest wholesale power producers in the U.S. Our portfolio is comprised of two fuel-efficient and clean power generation technologies: natural gas-fired combustion (primarily combined-cycle) facilities and renewable geothermal facilities. We own or lease 63 operating natural gas-fired power facilities in 18 states across the U.S. as well as 19 (17 active) geothermal facilities in the Geysers region of northern California. Our geothermal facilities comprise the largest producing geothermal resource in the U.S. Our natural gas-fired portfolio is equipped with state-of-the-art power generation technologies and is recognized as one of the most environmentally friendly and fuel-efficient fleets in the U.S.

We are focused on maximizing value by leveraging our portfolio of power plants, geographic diversity and 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.

Plan of Reorganization

On June 20, 2007, the U.S. Debtors filed the Plan of Reorganization with the U.S. Bankruptcy Court, together with the Disclosure Statement and portions of the Plan Supplement. The Plan of Reorganization, as well as the Disclosure Statement and Plan Supplement have been amended several times since June 20, 2007.

The Plan of Reorganization provides for the treatment of claims of creditors on a "waterfall" basis that allocates value to our creditors and shareholders in accordance with the priorities of the Bankruptcy Code. Pursuant to the Plan of Reorganization, allowed administrative claims and priority tax claims would be paid in full in cash or cash equivalents, as would allowed first and second lien debt claims. Other allowed secured claims would be reinstated, paid in full in cash or cash equivalents, or have the collateral securing such claims returned to the secured creditor. Allowed unsecured claims would receive a pro rata distribution of common stock of the reorganized Calpine Corporation; allowed unsecured convenience claims (all claims $50,000 or less) would be paid in full in cash or cash equivalents. Any remaining value after such allowed creditors' claims have been paid would be distributed pro rata to existing holders of allowed interests (primarily holders of existing Calpine Corporation common stock) and holders of subordinated equity securities claims in the form of reorganized Calpine Corporation common stock.

The Plan of Reorganization assumes that allowed claims plus Non-Debtor net project debt of $3.9 billion will range from $20.3 billion to $22.0 billion after completion of the claims objection, reconciliation and resolution process. However, because disputed claims, including litigation instituted by us challenging so-called “make whole,” premium, or “no-call” claims, have not yet been finally adjudicated, and our total enterprise value upon emergence has not yet been finally determined, no assurances can be given that actual recoveries to creditors and interest holders will not be materially higher or lower than proposed in the Plan of Reorganization. We intend to file an update to the valuation analysis of our total enterprise value upon emergence no later than ten days prior to the voting and objection deadline of November 30, 2007. The Disclosure Statement contains detailed information about the Plan of Reorganization, a historical profile of our business, a description of proposed distributions to creditors, and an analysis of the Plan of Reorganization’s feasibility, as well as many of the technical matters required for the exit process, such as descriptions of who will be eligible to vote on the Plan of Reorganization and the voting process itself. The information contained in the Disclosure Statement is subject to change, whether as a result of further amendments to the Plan of Reorganization, actions of third parties or otherwise.

On September 25, 2007, the U.S. Bankruptcy Court approved the adequacy of the Disclosure Statement, the solicitation and notice procedures with respect to confirmation of the Plan of Reorganization and the form of various ballots and notices in connection therewith. The U.S. Bankruptcy Court established September 27, 2007, as the record date for determining eligibility to vote on the Plan of Reorganization. We completed the distribution of solicitation packages by October 5, 2007, the deadline for distribution set by the U.S. Bankruptcy Court. Nothing contained in this Report is intended to be, nor should it be construed as, a solicitation for a vote on the Plan of Reorganization.

The Plan of Reorganization will become effective only if it receives the requisite approval and is confirmed by the U.S. Bankruptcy Court. The voting and objection deadline with respect to the Plan of Reorganization is scheduled for November 30, 2007, at which time we expect that our Plan of Reorganization, as it may be further amended, will be accepted and approved by our creditors. The confirmation hearing in the U.S. Bankruptcy Court is scheduled to begin on December 17, 2007. If the U.S. Bankruptcy Court confirms the Plan of Reorganization, we expect to emerge from Chapter 11 shortly thereafter. However, there can be no assurance that we will be successful in obtaining the necessary votes to approve the Plan of Reorganization, that the U.S. Bankruptcy Court will confirm the Plan of Reorganization or that it will be implemented successfully.

We have in place the $5.0 billion DIP Facility, which we believe will be sufficient to support our operations for the anticipated duration of our Chapter 11 cases and which may be converted to exit financing upon our emergence from Chapter 11. We have also secured a commitment for additional exit financing of up to $3.0 billion which, together with the amounts available upon conversion of the DIP Facility to exit financing will total $8.0 billion. See “— Liquidity and Capital Resources — DIP Facility.” The commitment to fund the additional facilities under the amended DIP Facility will expire on January 31, 2008, if certain conditions, including effectiveness of the Plan of Reorganization, are not met.

We had the exclusive right until August 20, 2007, to solicit acceptance of the Plan of Reorganization. The exclusivity period has expired and competing plans of reorganization may be filed by third parties.

2007 Outlook

We expect our results of operations to continue to be impacted by our actions while in Chapter 11 as well as future power prices, fuel prices, fuel availability and unit availability. Spreads between power and fuel prices are expected to remain volatile as power and fuel prices change based on demand, weather and other factors.

In addition, we expect that our financial results could be volatile throughout 2007 and through our emergence from Chapter 11 as our restructuring activities will likely result in additional charges for expected allowed claims, adjustments to existing provisions for expected allowed claims based upon approved settlements or resolutions and other reorganization items that could be material to our financial position or results of operations in any given period.

Future Performance Indicators

Our historical financial performance is likely not indicative of our future financial performance during the pendency of the Chapter 11 cases and CCAA proceedings or beyond because, among other things: (i) we generally will not accrue interest expense on our debt classified as LSTC during the pendency of our Chapter 11 cases, except pursuant to orders of the U.S. Bankruptcy Court; (ii) we have and expect to further dispose of, or restructure agreements relating to, certain plants that do not generate positive cash flow or which are otherwise considered non-strategic; (iii) we have implemented overhead reduction programs, including staff reductions and non-core office closures; (iv) we have been able to or have sought to reject, repudiate or terminate certain unprofitable or burdensome contracts and leases, and we may further seek to reject, repudiate or terminate contracts and leases in the future; (v) we have been able to or are seeking to assume certain beneficial contracts and leases, and we may further seek to assume contracts and leases in the future in accordance with the time frames set forth in the Bankruptcy Code; (vi) we have deconsolidated certain Canadian and other foreign subsidiaries as a result of the CCAA proceedings and currently account for our investment in such entities under the cost method; (vii) as part of our emergence from Chapter 11, we may be required to adopt fresh start accounting in a future period, resulting in the remeasurement of our assets and liabilities to fair value as of the fresh start reporting date, which may differ materially from historical balances; and (viii) if fresh start accounting is required, our financial results after the application of fresh start accounting may be different from historical trends.

We believe that we have taken and will continue to take the necessary steps to successfully emerge from Chapter 11. We are currently soliciting votes on our Plan of Reorganization; however, until we have a confirmed plan or plans or reorganization, we believe the following factors are important in assessing our ability to continue to fund our operations and to successfully reorganize and emerge from Chapter 11 as a sustainable, competitive and profitable power company: (i) reducing our activities in certain non-core areas and lowering overhead and operating expenses; (ii) improving the profitability of our operations; (iii) complying with the covenants related to our existing financing obligations and anticipated exit financing; (iv) successfully executing our anticipated exit financing to provide adequate capital upon emergence from Chapter 11; and (v) stabilizing and increasing future contractual cash flows.

Results of Operations for the Three Months Ended September 30, 2007 and 2006

Set forth below are the results of operations for the three months ended September 30, 2007, as compared to the same period in 2006 (in millions, except for unit pricing information, MWh and percentages). In the comparative tables below, increases in revenue/income or decreases in expense (favorable variances) are shown without parentheses while decreases in revenue/income or increases in expense (unfavorable variances) are shown with parentheses in the “$ Change” and “% Change” columns.

	Three Months Ended September 30,			
	2007	2006	$ Change	% Change
Revenue:				
Electricity and steam revenue	$ 1,690	$ 1,842	$ (152)	(8)%
Sales of purchased power and gas for hedging and optimization	540	273	267	98
Mark-to-market activities, net	2	28	(26)	(93)
Other revenue	7	15	(8)	(53)
Total revenue	2,239	2,158	81	4
Cost of revenue:				
Plant operating expense	182	175	(7)	(4)
Purchased power and gas expense for hedging and optimization	370	296	(74)	(25)
Fuel expense	1,114	1,106	(8)	(1)
Depreciation and amortization expense	114	121	7	6
Operating lease expense	15	11	(4)	(36)
Other cost of revenue	32	39	7	18
Total cost of revenue	1,827	1,748	(79)	(5)
Gross profit	412	410	2	—
Equipment, development project and other impairments	—	(4)	(4)	#
Sales, general and administrative expense	33	49	16	33
Other operating expense	12	10	(2)	(20)
Income from operations	367	355	12	3
Interest expense	602	228	(374)	#
Interest (income)	(14)	(19)	(5)	(26)
Minority interest expense	1	7	6	86
Other (income) expense, net	(127)	(10)	117	#
Income (loss) before reorganization items and income taxes	(95)	149	(244)	#
Reorganization items	(3,940)	146	4,086	#
Income before income taxes	3,845	3	3,842	#
Provision for income taxes	51	1	(50)	#
Net income	$ 3,794	$ 2	$ 3,792	#

\# Variance of 100% or greater

Total revenue for the three months ended September 30, 2007, increased by $81 million, or 4%, as compared to the same period a year ago, primarily due to a 98% increase in sales of purchased power and gas for hedging and optimization which was partially offset by an 8% decrease in electricity and steam revenue. In addition, mark-to-market activity decreased $26 million when compared to the same period in 2006, as discussed further below. The increase in sales of purchased power and gas primarily resulted from higher hedging and optimization activity during the third quarter of 2007 compared to the same period in 2006. The reduction in the availability of credit and the termination or disruption of certain customer relationships due to our Chapter 11 filings had curtailed the amount of hedging and optimization activity during 2006 while these conditions have been less of a factor in 2007. Correspondingly, purchased power and gas expense for hedging and optimization also increased by 25% for similar reasons.

Electricity and steam revenue, as shown in the following table, decreased primarily due to an 11% decrease in energy revenue driven by a 4% decrease in generation and 7% lower realized energy revenue per MWh. Our average baseload MW in operation declined 9% due largely to our asset sales in late 2006 and in 2007. In addition to this decline, some of our markets, particularly Texas, experienced cooler than average temperatures during the three months ended September 30, 2007, resulting in decreased demand over the same period a year ago when we had experienced warmer than average weather in most of our markets. For the three months ended September 30, 2007, our average baseload capacity factor increased to 54.6% from 52.1% in the same period in 2006. See "— Operating Performance Metrics," below for an explanation of average baseload capacity factor. Capacity revenues, which are not related to production and include traditional capacity payments and other revenues (such as RMR Contract, resource adequacy and ancillary service revenues), decreased by 4% during the three months ended September 30, 2007. Thermal and other revenue, which primarily consists of host steam sales, increased $19 million or 20% resulting primarily from favorable pricing on a renegotiated steam contract which became effective in early 2007.

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	$ Change	% Change
	(Dollars in millions, except pricing data)			
Electricity and steam revenue:				
Energy	$ 1,316	$ 1,475	$ (159)	(11)%
Capacity	259	271	(12)	(4)
Thermal and other	115	96	19	20
Total electricity and steam revenue	$ 1,690	$ 1,842	$ (152)	(8)
MWh generated (in thousands)	27,223	28,385	(1,162)	(4)
Average electricity and steam revenue per MWh generated*	$ 62.08	$ 64.89	$ (2.81)	(4)
Average energy revenue per MWh generated	$ 48.34	$ 51.96	$ (3.62)	(7)

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* Exclusive of hedging and optimization activity.

Mark-to-market activities, which are shown on a net basis and detailed in the table below, result from general market price movements against our open commodity and interest rate derivative positions not designated as hedges. These commodity and interest rate positions represent a small portion of our overall commodity and interest rate contract position.

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	$ Change	% Change
	(Dollars in millions)			
Mark-to-market activities, net:				
Deer Park Energy Center	$ 36	$ 27	$ 9	33%
Gas	(14)	9	(23)	#
Power	(14)	13	(27)	#
Interest rate swaps and other	(6)	(21)	15	71
Total mark-to-market activities, net	$ 2	$ 28	$ (26)	(93)

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Variance of 100% or greater

During the three months ended September 30, 2007, the $9 million favorable mark-to-market variance relating to the Deer Park Energy Center is primarily due to unrealized gains on power derivatives relating to our Deer Park power plant.

The unfavorable mark-to-market variance in gas is primarily due to losses during the three months ended September 30, 2007, on certain gas positions used to economically hedge one of our transport contracts. The unfavorable mark-to-market variance in power is primarily due to losses on certain power trades used to economically hedge one of our transmission contracts.

Although the above-mentioned gas and power positions are economic hedges, they do not qualify for hedge accounting under derivative accounting rules and are marked-to-market through earnings. Further, we account for the hedged items (the transport and transmission contracts) on an accrual basis and the offsetting economic gains are not recognized through mark-to-market earnings in the same accounting period.

Fuel expense increased during the three months ended September 30, 2007, as compared to the same period in 2006 primarily due to a 14% increase in average fuel cost per MMBtu partially offset by a 10% decrease in the MMBtu of fuel consumed by the generating plants as a result of decreased production during the three months ended September 30, 2007, as compared to the same period in 2006.

As a result of the foregoing items, gross profit for the three months ended September 30, 2007, improved by $2 million compared to the same period in 2006.

Interest expense increased primarily due to $318 million in post-petition interest related to the ULC I notes recorded during the three months ended September 30, 2007, resulting from the Canadian Settlement Agreement, while no similar expense was recorded in the comparable period of the prior year. Also contributing to the increase was a $92 million increase in interest expense related to the additional adequate protection payments granted to the holders of our Second Priority Debt. We had discontinued these adequate protection payments as of June 30, 2006, based on previous orders of the U.S. Bankruptcy Court, until the additional adequate protection payments were granted in December 2006. The increase was partially offset by the net effect of the refinancings of the CalGen Secured Debt and the Original DIP Facility in late March 2007 using funds available under the DIP Facility, which carries lower interest rates, as well as an additional $16 million decrease due to the extinguishment of certain project financing as a result of our asset sales, principally related to the Fox Energy Center. See Note 2 of the Notes to Consolidated Condensed Financial Statements and "— Liquidity and Capital Resources" below for further information related to our recognition of interest expense for the Second Priority Debt during our reorganization as well as for the Canadian Settlement Agreement. We currently accrue interest on our pre-petition LSTC only to the extent that it will be paid during the pendency of our Chapter 11 cases or is permitted by the Cash Collateral Order or pursuant to orders of the U.S. Bankruptcy Court. Our Plan of Reorganization ultimately confirmed could include allowed claims for substantial post-petition interest which could further negatively impact the comparability of future interest expense.

Other income, net increased primarily as a result of $129 million in income pertaining to a claim settlement with a customer which received court approval during the three months ended September 30, 2007. The claim, which was approved by the court hearing the customer's bankruptcy case, related to the customer's rejection of our energy services agreement following the customer's bankruptcy filing and is unrelated to our Chapter 11 cases. The increase was partially offset by $7 million in foreign exchange losses and a $5 million settlement arising from pre-petition litigation related to the Goldendale Energy Center, both of which were recorded during the three months ended September 30, 2007.

The table below lists the significant components of reorganization items for the three months ended September 30, 2007 and 2006.

	Three Months Ended September 30, 2007	2006	$ Change	% Change
	(Dollars in millions)			
Provision for expected allowed claims	$ (4,030)	$ 94	$ 4,124	#%
Gains on asset sales	(36)	—	36	—
DIP Facility financing costs	22	3	(19)	#
Professional fees	44	39	(5)	(13)
Interest (income) on accumulated cash	(16)	(5)	11	#
Other	76	15	(61)	#
Total reorganization items	$ (3,940)	$ 146	$ 4,086	#

Variance of 100% or greater

Provision for Expected Allowed Claims — During the three months ended September 30, 2007, our provision for expected allowed claims consisted primarily of (i) a $4.1 billion credit related to the settlement of claims with respect to Calpine Corporation's direct and indirect guarantees of the ULC I notes, the release of our guarantee of the ULC II notes following repayment of those notes in September 2007 and pre-petition intercompany balances, (ii) accruals totaling $154 million for make whole premiums and/or damages related to the Second Priority Debt and Unsecured Notes settlements and (iii) a $98 million credit resulting from the negotiated settlement of repudiated gas transportation contracts. During the three months ended September 30, 2006, our provision for expected allowed claims consisted primarily of an accrual of $94 million related to an expected allowed claim for a repudiated gas transportation contract.

Gain on Asset Sales — During the three months ended September 30, 2007, gains on asset sales related primarily to our sale of the Parlin Power Plant. See Note 5 of the Notes to Consolidated Condensed Financial Statements and "— Liquidity and Capital Resources — Asset Sales" below for further information.

DIP Facility Financing Costs — During the three months ended September 30, 2007, we recorded transaction costs of $22 million related to the execution of a commitment letter to fund our additional exit financing. See Note 7 of the Notes to Consolidated Condensed Financial Statements and "— Liquidity and Capital Resources — DIP Facility" below for further information.

Other — Other reorganization items for the three months ended September 30, 2007, increased primarily due to a $60 million increase in foreign exchange losses on LSTC denominated in a foreign currency over the comparable period in the prior year.

We recorded a tax provision of $51 million during the three months ended September 30, 2007, as compared to a tax provision of $1 million during the same period in 2006. See Note 1 of the Notes to Consolidated Condensed Financial Statements for further information regarding our income taxes.

Results of Operations for the Nine Months Ended September 30, 2007 and 2006

Set forth below are the results of operations for the nine months ended September 30, 2007, as compared to the same period in 2006 (in millions, except for unit pricing information, MWh and percentages). In the comparative tables below, increases in revenue/income or decreases in expense (favorable variances) are shown without parentheses while decreases in revenue/income or increases in expense (unfavorable variances) are shown with parentheses in the "$ Change" and ''% Change" columns.

	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006	$ Change	% Change
Revenue:				
Electricity and steam revenue	$ 4,412	$ 4,070	$ 342	8%
Sales of purchased power and gas for hedging and optimization	1,357	891	466	52
Mark-to-market activities, net	5	88	(83)	(94)
Other revenue	55	57	(2)	(4)
Total revenue	5,829	5,106	723	14
Cost of revenue:				
Plant operating expense	561	520	(41)	(8)
Purchased power and gas expense for hedging and optimization	1,046	857	(189)	(22)
Fuel expense	2,989	2,474	(515)	(21)
Depreciation and amortization expense	350	350	—	—
Operating plant impairments	—	53	53	#
Operating lease expense	39	53	14	26
Other cost of revenue	112	128	16	13
Total cost of revenue	5,097	4,435	(662)	(15)
Gross profit	732	671	61	9
Equipment, development project and other impairments	2	64	62	97
Sales, general and administrative expense	112	147	35	24
Other operating expense	22	25	3	12
Income from operations	596	435	161	37
Interest expense	1,176	820	(356)	(43)
Interest (income)	(48)	(59)	(11)	(19)
Minority interest expense	—	10	10	#
Other (income) expense, net	(134)	7	141	#
Loss before reorganization items and income taxes	(398)	(343)	(55)	(16)
Reorganization items	(3,366)	1,099	4,465	#
Income (loss) before income taxes	2,968	(1,442)	4,410	#
Provision (benefit) for income taxes	133	(36)	(169)	#
Income (loss) before cumulative effect of a change in accounting principle	2,835	(1,406)	4,241	#
Cumulative effect of a change in accounting principle, net of tax	—	1	(1)	#
Net income (loss)	$ 2,835	$ (1,405)	$ 4,240	#

\# Variance of 100% or greater

Total revenue for the nine months ended September 30, 2007, increased by $723 million, or 14%, as compared to the same period a year ago, primarily due to an 8% increase in electricity and steam revenue and a 52% increase in sales of purchased power and gas for hedging and optimization. Mark-to-market activity decreased $83 million when compared to the same period in 2006, as discussed further below. The increase in sales of purchased power and gas primarily resulted from higher hedging and optimization activity and from marginally higher commodity prices during the nine months ended September 30, 2007, compared to the same period in 2006. The reduction in the availability of credit and the termination or disruption of certain customer relationships due to our Chapter 11 filings and reduced generation in 2006 had curtailed the amount of hedging and optimization activity during that period while these conditions have been less of a factor in 2007. Correspondingly, purchased power and gas expense for hedging and optimization also increased by 22% for similar reasons.

Electricity and steam revenue, as shown in the following table, increased primarily due to a 9% increase in energy revenue driven by a 10% increase in generation. Our average baseload MW in operation declined 8% due largely to our asset sales in late 2006 and in 2007. Despite this decline, most of our markets experienced favorable temperatures during the first half of 2007, resulting in increased demand over the same period a year ago when we had experienced mild weather in most of our markets. Some of our markets, particularly Texas, experienced cooler than average temperatures during the third quarter of 2007, resulting in decreased demand over the same period a year ago when we had experienced warmer than average weather in most of our markets. For the nine months ended September 30, 2007, our average baseload capacity factor increased to 46.5% from 39.2% in the same period in 2006. See "— Operating Performance Metrics," below for an explanation of average baseload capacity factor. Capacity revenues, which are not related to production and include traditional capacity payments and other revenues (such as RMR Contract, resource adequacy and ancillary service revenues), decreased by 1% during the nine months ended September 30, 2007. Thermal and other revenue, which primarily consists of host steam sales, increased by $69 million or 25% resulting primarily from favorable pricing on a renegotiated steam contract which became effective in early 2007.

	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006	$ Change	% Change
	(Dollars in millions, except pricing data)			
Electricity and steam revenue:				
Energy	$ 3,349	$ 3,068	$ 281	9%
Capacity	718	726	(8)	(1)
Thermal and other	345	276	69	25
Total electricity and steam revenue	$ 4,412	$ 4,070	$ 342	8
MWh generated (in thousands)	69,005	62,826	6,179	10
Average electricity and steam revenue per MWh generated*	$ 63.94	$ 64.78	$ (0.84)	(1)
Average energy revenue per MWh generated	$ 48.53	$ 48.83	$ (0.30)	(1)

* Exclusive of hedging and optimization activity.

Mark-to-market activities, which are shown on a net basis and detailed in the table below, result from general market price movements against our open commodity and interest rate derivative positions not designated as hedges. These commodity and interest rate positions represent a small portion of our overall commodity and interest rate contract position.

	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006	$ Change	% Change
	(Dollars in millions)			
Mark-to-market activities, net:				
Deer Park Energy Center	$ 83	$ 41	$ 42	#%
Gas	(49)	43	(92)	#
Power	(24)	(5)	(19)	#
Interest rate swaps and other	(5)	9	(14)	#
Total mark-to-market activities, net	$ 5	$ 88	$ (83)	(94)

Variance of 100% or greater

During the nine months ended September 30, 2007, the $42 million favorable mark-to-market variance relating to the Deer Park Energy Center is primarily due to gains on power derivatives relating to our Deer Park power plant.

The unfavorable mark-to-market variance in gas is primarily due to losses during the nine months ended September 30, 2007, on certain gas positions used to economically hedge one of our transport contracts. The unfavorable mark-to-market variance in power is primarily due to losses during the nine months ended September 30, 2007, on certain power trades used to economically hedge one of our transmission contracts.

Although the above-mentioned gas and power positions are economic hedges, they do not qualify for hedge accounting under derivative accounting rules and are marked-to-market through earnings. Further, we account for the hedged items (the transport and transmission contracts) on an accrual basis and the offsetting economic gains are not recognized through mark-to-market earnings in the same accounting period.

Plant operating expense increased primarily due to an increase of $38 million in major maintenance and equipment failure costs during the nine months ended September 30, 2007, compared to the same period in the prior year. During the nine months ended September 30, 2006, major maintenance costs were lower than normal due to decreased generation owing to weakened demand; as a result, certain major maintenance work was delayed until later in 2006 or deferred until 2007. Equipment failure costs increased during the nine months ended September 30, 2007, due to losses on the retirement of scrap parts related to outages.

Fuel expense increased during the nine months ended September 30, 2007, as compared to the same period in 2006 primarily due to a 12% increase in the average fuel cost per MMBtu and a 9% increase in MMBtu of fuel consumed by generating plants as a result of increased production, primarily during the first half of 2007, as compared to the same period in 2006.

During the nine months ended September 30, 2006, we recorded total impairment charges of $117 million primarily due to $64 million relating to turbine-generator equipment and $50 million relating to Fox Energy Center. The majority of our impairment charges recorded during the nine months ended September 30, 2007, related to our restructuring activities and are included in reorganization items as discussed below.

Operating lease expense decreased by $14 million primarily due to a decrease of $9 million related to the rejection of the Rumford and Tiverton leases in June 2006. The decrease is also partly attributable to a $2 million decrease associated with a sale-leaseback agreement at the Geysers Assets that was cancelled in February 2006.

As a result of the foregoing items, gross profit for the nine months ended September 30, 2007, improved by $61 million, or 9%, compared to the same period in 2006.

Sales, general and administrative expense decreased primarily due to the overall reduction in workforce and resultant $12 million net reduction in personnel cost as well as higher allocations of information technology costs to power plant operating expense of $20 million.

Interest expense increased primarily due to $318 million in post-petition interest related to the ULC I notes recorded during the three months ended September 30, 2007, resulting from the Canadian Settlement Agreement, while no similar expense was recorded in the comparable period of the prior year. Also contributing to the increase was a $118 million increase in interest expense related to the additional adequate protection payments granted to the holders of our Second Priority Debt in December 2006. We had discontinued these adequate protection payments as of June 30, 2006. The increase was partially offset by the net effect of the refinancings of the CalGen Secured Debt and the Original DIP Facility in late March 2007 using funds available under the DIP Facility, which carries lower interest rates, the repayment of the First Priority Notes in May and June of 2006 using funds available under the Original DIP Facility which carried lower interest rates, and an additional $31 million decrease due to the extinguishment of certain project financing as a result of our asset sales, principally related to the Fox Energy Center. See Note 2 of the Notes to Consolidated Condensed Financial Statements and "— Liquidity and Capital Resources" below for further information related to our recognition of interest expense for the Second Priority Debt during our reorganization as well as for the Canadian Settlement Agreement. We currently accrue interest on our pre-petition LSTC only to the extent that it will be paid during the pendency of our Chapter 11 cases or is permitted by the Cash Collateral Order or pursuant to orders of the U.S. Bankruptcy Court. Our Plan of Reorganization ultimately confirmed could include allowed claims for substantial post-petition interest which could further negatively impact the comparability of future interest expense.

Other (income) expense, net increased primarily as a result of $129 million in income pertaining to a claim settlement with a customer which received court approval during the three months ended September 30, 2007. The claim, which was approved by the court hearing the customer's bankruptcy case, related to the customer's rejection of our energy services agreement following the customer's bankruptcy filing and is unrelated to our Chapter 11 cases.

The table below lists the significant components of reorganization items for the nine months ended September 30, 2007 and 2006.

	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006	$ Change	% Change
	(Dollars in millions)			
Provision for expected allowed claims	$ (3,695)	$ 883	$ 4,578	#%
Gains on asset sales	(286)	—	286	—
Asset impairments	120	2	(118)	#
DIP Facility financing and CalGen Secured Debt repayment costs	182	35	(147)	#
Professional fees	139	107	(32)	(30)
Interest (income) on accumulated cash	(39)	(18)	21	#
Other	213	90	(123)	#
Total reorganization items	$ (3,366)	$ 1,099	$ 4,465	#

\# Variance of 100% or greater

Provision for Expected Allowed Claims — During the nine months ended September 30, 2007, our provision for expected allowed claims consisted primarily of (i) a $4.1 billion credit related to the settlement of claims with respect to Calpine Corporation's direct and indirect guarantees of the ULC I notes, the release of our guarantee of the ULC II notes following repayment of those notes in September 2007 and pre-petition intercompany balances, (ii) accruals totaling $154 million for make whole premiums and/or damages related to the Second Priority Debt and Unsecured Notes settlements, (iii) $112 million resulting from the repudiation of a gas transportation contract, (iv) a $98 million credit resulting from the negotiated settlement of repudiated gas transportation contracts, (v) $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, (vi) 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 have agreed to allow general unsecured claims in the aggregate of $190 million, and (vii) $65 million resulting from a stipulated settlement related to the RockGen Energy Center. During the nine months ended September 30, 2006, our provision for expected allowed claims related primarily to repudiated gas transportation and power transmission contracts, the rejection of the Rumford and Tiverton power plant leases, the write-off of prepaid lease expense and certain fees and expenses related to the transaction and a claim resulting from Calpine Corporation's guarantee related to CES-Canada's repudiation of its tolling contract with Calgary Energy Centre.

Gains on Asset Sales — During the nine months ended September 30, 2007, gains on asset sales primarily resulted from the sale of the Aries Power Plant, Goldendale Energy Center, PSM and Parlin Power Plant during 2007 with no comparable activity in the prior year. See Note 5 of the Notes to Consolidated Condensed Financial Statements and "— Liquidity and Capital Resources — Asset Sales" below for further information.

Asset Impairments — During the nine months ended September 30, 2007, asset impairment charges were primarily due to a pre-tax, predominately non-cash impairment charge of approximately $89 million in reorganization items to record our interest in Acadia PP at fair value less cost to sell. See Note 5 of the Notes to Consolidated Condensed Financial Statements and "— Liquidity and Capital Resources — Asset Sales" below for further information. Asset impairment charges during the comparable period in 2006 relating primarily to turbine-generator equipment and Fox Energy Center are discussed above.

DIP Facility Financing and CalGen Secured Debt Repayment Costs — During the nine months ended September 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. We also recorded transaction costs of $22 million related to the execution of a commitment letter to fund our additional exit financing during the current year period. See Note 7 of the Notes to Consolidated Condensed Financial Statements and "— Liquidity and Capital Resources — DIP Facility and — Repayment of CalGen Secured Debt" below for further information.

Professional Fees — The increase in professional fees for the nine months ended September 30, 2007, over the comparable period in 2006 resulted primarily from an increase in activity managed by our third party advisors including our Plan of Reorganization, litigation and claims reconciliation matters.

Other — Other reorganization items increased primarily due to a $104 million increase in foreign exchange losses on LSTC denominated in a foreign currency over the comparable period in the prior year and a charge of $14 million during the nine months ended September 30, 2007, resulting from debt pre-payment and make whole premium fees to the project lenders related to the sale of the Aries Power Plant.

We recorded a tax provision of $133 million during the nine months ended September 30, 2007, as compared to a tax benefit of $36 million during the same period in 2006. See Note 1 of the Notes to Consolidated Condensed Financial Statements for further information regarding our income taxes.

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 certain non-GAAP financial measures, such as all-in realized spark spread, as defined and calculated in "— Operating Performance Metrics." In addition, our management utilizes another non-GAAP financial measure, Adjusted EBITDA, 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.

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 a material covenant under our DIP Facility which is our primary source of financing during the Chapter 11 cases. Under the DIP Facility, we are required to maintain certain levels of Adjusted EBITDA (called "Consolidated EBITDA" in the DIP Facility) on a rolling 12 month basis and as of certain points in time. Non-compliance with this covenant could result in the lenders requiring us to immediately repay all amounts borrowed. In addition, if we cannot satisfy this financial covenant, we may be prohibited from engaging in other activities, such as incurring additional indebtedness.

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 are currently recognizing substantial reorganization items, both direct and incremental, in connection with our Chapter 11 cases. In addition, we have incurred substantial asset impairment charges related to our Chapter 11 filings and actions we have taken with respect to our portfolio of assets. Since the Petition Date, these reorganization items and impairment charges have been significant but are not expected to continue at these levels as we emerge from Chapter 11. 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.

Our management uses Adjusted EBITDA (i) as a measure of liquidity in determining our ability to maintain borrowings under the DIP 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):

	Three Months Ended September 30, 2007	Three Months Ended September 30, 2006	Nine Months Ended September 30, 2007	Nine Months Ended September 30, 2006
	(in millions)			
Cash provided by operating activities	$ 268	$ 371	$ 93	$ 167
Less:				
Changes in operating assets and liabilities, excluding the effects of acquisition	217	85	139	18
Additional adjustments to reconcile GAAP net income (loss) to net cash provided by operating activities from both continuing and discontinued operations:				
Depreciation and amortization expense(1)	136	148	420	437
Deferred income taxes, net	50	1	132	(36)
Mark-to-market activities, net	(2)	(28)	(5)	(88)
Non-cash reorganization items	(3,956)	106	(3,459)	976
Impairment charges and other	29	57	31	265
GAAP net income (loss)	3,794	2	2,835	(1,405)
Add:				
Adjustments to reconcile GAAP net loss to Adjusted EBITDA:				
Interest expense, net of interest income	588	209	1,128	761
Depreciation and amortization expense(1)	125	134	383	389
Income tax provision (benefit)	51	1	133	(36)
Impairment charges	—	(4)	2	117
Reorganization items	(3,940)	146	(3,366)	1,099
Major maintenance expense	4	31	78	64
Operating lease expense	15	11	39	53
(Gains) on derivatives (non-cash portion)	(6)	(28)	(18)	(178)
Non-cash loss on repurchase of debt	—	—	—	18
Claim settlement income	(129)	—	(129)	—
Other	3	(11)	(4)	(6)
Adjusted EBITDA	$ 505	$ 491	$ 1,081	$ 876

(1) Depreciation and amortization in the GAAP net income (loss) calculation includes items, such as deferred financing costs and discounts/premiums, which are included in interest expense, net of interest income in the Adjusted EBITDA calculation.

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:

- *MWh generated*. We generate power that we sell to third parties. These sales are recorded as electricity and steam revenue. The volume in MWh is a direct indicator of our level of electricity generation activity.

- *Average availability and average baseload capacity factor*. 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 baseload capacity factor is calculated by dividing (a) total MWh generated by our power plants (excluding peaker facilities) 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 baseload capacity factor is thus a measure of total actual generation as a percent of total potential generation. If we elect not to generate during periods when electricity pricing is too low or gas prices too high to operate profitably, the baseload capacity factor will reflect that decision as well as both scheduled and unscheduled outages due to maintenance and repair requirements.

- *Average Heat Rate for gas-fired fleet of power plants (excluding peakers) expressed in Btus of fuel consumed per KWh generated*. We calculate the average Heat Rate for our gas-fired power plants (excluding peaker facilities) by dividing (a) fuel consumed in Btu by (b) KWh generated. The resultant Heat Rate is a measure of fuel efficiency, so the lower the Heat Rate, the lower our cost of generation. We also calculate a "steam-adjusted" Heat Rate, in which 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.

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

- *Average cost of natural gas expressed in dollars per MMBtu of fuel consumed*. Our risk management and optimization activities related to fuel procurement directly impact our total fuel expense. The fuel costs for our gas-fired power plants are a function of the price we pay for fuel purchased and the results of the fuel hedging, balancing, and optimization activities. 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 (adding back cost of inter-company gas pipeline costs, which is eliminated in consolidation), the spread on sales of purchased gas for hedging, balancing, and optimization activity, and fuel expense related to generation recorded in mark-to-market activities, net by (b) the heat content in millions of Btu of the fuel we consumed in our power plants for the period.

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

- *Average plant operating expense per MWh*. To assess trends in electric power plant operating expense, or POX, per MWh, we divide POX by total MWh generated in the period.

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

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2007	2006	2007	2006
	(in thousands, except hours in period, percentages, Heat Rate, price and cost information)			
Operating Performance Metrics:				
MWh generated	27,223	28,385	69,005	62,826
Average availability	93.9%	95.8%	91.5%	92.6%
Average baseload capacity factor:				
Average total MW in operation	24,854	26,900	25,098	26,942
Less: Average MW of peaker facilities	3,019	2,965	3,013	2,965
Average baseload MW in operation	21,835	23,935	22,085	23,977
Hours in the period	2,208	2,208	6,552	6,552
Potential baseload generation (MWh)	48,212	52,848	144,701	157,097
Actual total generation (MWh)	27,223	28,385	69,005	62,826
Less: Actual peaker facilities' generation (MWh)	880	866	1,651	1,230
Actual baseload generation (MWh)	26,343	27,519	67,354	61,596
Average baseload capacity factor	54.6%	52.1%	46.5%	39.2%
Average Heat Rate for gas-fired power plants (excluding peakers)(Btu's/KWh):				
Not steam adjusted	8,107	7,999	8,213	8,372
Steam adjusted	7,211	7,213	7,172	7,235
Average all-in realized electric price:				
Electricity and steam revenue	$ 1,689,992	$ 1,842,575	$ 4,411,782	$ 4,070,045
Spread on sales of purchased power for hedging and optimization	166,097	(32,372)	307,149	28,461
Revenue related to power generation in mark-to-market activity, net	78,241	56,413	230,074	142,585
Adjusted electricity and steam revenue	$ 1,934,330	$ 1,866,616	$ 4,949,005	$ 4,241,091
MWh generated	27,223	28,385	69,005	62,826
Average all-in realized electric price per MWh	$ 71.05	$ 65.76	$ 71.72	$ 67.51
Average cost of natural gas:				
Fuel expense	$ 1,114,132	$ 1,105,248	$ 2,989,318	$ 2,473,657
Fuel cost elimination	4,602	3,132	12,646	9,158
Spread on sales of purchased gas for hedging and optimization	(4,520)	(8,920)	(4,362)	(5,148)
Fuel expense related to power generation in mark-to-market activity, net	42,677	35,111	155,663	111,409
Adjusted fuel expense	$ 1,156,891	$ 1,134,571	$ 3,153,265	$ 2,589,076
MMBtu of fuel consumed by generating plants	174,719	195,181	462,567	426,027
Average cost of natural gas per MMBtu	$ 6.62	$ 5.81	$ 6.82	$ 6.08
MWh generated	27,223	28,385	69,005	62,826
Average cost of adjusted fuel expense per MWh	$ 42.50	$ 39.97	$ 45.70	$ 41.21
All-in realized spark spread:				
Adjusted electricity and steam revenue	$ 1,934,330	$ 1,866,616	$ 4,949,005	$ 4,241,091
Less: Adjusted fuel expense	1,156,891	1,134,571	3,153,265	2,589,076
All-in realized spark spread	$ 777,439	$ 732,045	$ 1,795,740	$ 1,652,015
MWh generated	27,223	28,385	69,005	62,826
All-in realized spark spread per MWh	$ 28.56	$ 25.79	$ 26.02	$ 26.30
Average plant operating expense (POX) per actual MWh:				
POX	$ 182,137	$ 174,552	$ 560,852	$ 519,877
POX per actual MWh	$ 6.69	$ 6.15	$ 8.13	$ 8.27

Liquidity and Capital Resources

Currently, the Calpine Debtors continue to conduct business in the ordinary course as debtors-in-possession under the protection of the Bankruptcy Courts. Accordingly, the matters described in this section may be significantly affected by our Chapter 11 cases and CCAA proceedings, and by the risks and other factors described in "Forward-Looking Statements," including the risk factors included in Item 1A. "Risk Factors" included in our 2006 Form 10-K.

Our business is capital intensive. Our ability to successfully reorganize and emerge from Chapter 11 protection, while continuing to operate our current fleet of power plants, including 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, is dependent on the continued availability of capital on attractive terms. We have in place the $5.0 billion DIP Facility, which we believe will be sufficient to support our operations for the anticipated duration of our Chapter 11 cases and which may be converted to exit financing upon our emergence from Chapter 11. We have also secured a commitment for additional exit financing of up to $3.0 billion which, together with the amounts available upon conversion of the DIP Facility to exit financing will total $8.0 billion. We expect the amounts under the DIP Facility and commitment for additional exit financing will be sufficient to emerge from Chapter 11 and support our operations upon our emergence from Chapter 11. See "— DIP Facility" below for further information. We have obtained U.S. Bankruptcy Court approval of several other matters that we believe are important to maintaining our ability to operate in the ordinary course during our Chapter 11 cases, including (i) our cash management program (as described under "Cash Management" below), (ii) payments to our employees, vendors and suppliers necessary in order to keep our facilities operational and (iii) procedures for the rejection of certain leases and executory contracts.

We currently obtain cash from our general operations, borrowings under credit facilities, including the DIP Facility, sale or partial sale of certain assets, and project financings or refinancings. In the past, we have also obtained cash from issuances of debt, equity, trust preferred securities and convertible debentures and contingent convertible notes; proceeds from sale/leaseback transactions; and contract monetizations, and we or our subsidiaries may in the future complete similar transactions in order to fund our ongoing operations. We utilize cash to fund our operations, service or prepay debt obligations, 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 do not intend, nor do we anticipate being able, to pay any cash dividends on our common stock in the foreseeable future because of our Chapter 11 cases and liquidity constraints. In addition, our ability to pay cash dividends is restricted under certain of our indentures and our other debt agreements. Future cash dividends, if any, following our emergence from Chapter 11 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. Trading in our common stock during the pendency of our Chapter 11 cases and CCAA proceedings is highly speculative and poses substantial risks. The U.S. Bankruptcy Court has imposed restrictions on trading in our common stock and certain securities, including options, convertible into our common stock, and, in order to preserve our ability to utilize our NOL carryforwards after the effective date of the Plan of Reorganization, we have proposed restrictions on certain transfers of the reorganized Calpine Corporation common stock. Holders of our common stock may not be able to resell such securities and, in connection with our reorganization, may have their securities cancelled and receive no payment or other consideration in return.

In order to improve our liquidity position, we have taken steps 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, particularly in the near term. Our development activities have been reduced, and we have only one project currently in active development. We are actively marketing two projects for which construction was suspended in 2005. We continue to review our remaining, less advanced development opportunities, which we have put on hold, to determine what actions we should take; we may pursue new opportunities that arise, 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 or the agreements relating to certain of our facilities may be restructured, or that commercial operations may be suspended at certain of our power plants. See "— Asset Sales" below for further details.

We pay current interest on debt of the Calpine Debtors that has been determined to be fully secured and make payments of interest or principal, as applicable, on the debt of our subsidiaries that have not filed for protection under Chapter 11 nor are subject to the CCAA proceedings. Pursuant to the Cash Collateral Order, we make periodic cash adequate protection payments to the holders of Second Priority Debt; originally payments were made only through June 30, 2006, but, by order entered December 28, 2006, the U.S. Bankruptcy Court modified the Cash Collateral Order to provide for periodic adequate protection payments on a quarterly basis to the holders of outstanding Second Priority Debt through December 31, 2007. Thereafter, unless we have a confirmed plan or plans of reorganization and are no longer subject to U.S. Bankruptcy Court jurisdiction, the holders of Second Priority Debt must seek further orders from the U.S. Bankruptcy Court for any further amounts to be paid. We have not yet made a determination as to whether any portion of the adequate protection payments represents payment of principal and, therefore, have reported the full amount of the adequate protection payments as interest expense on our Consolidated Condensed Statements of Operations. We do not generally pay interest or make other debt service payments on the debt of the Calpine Debtors classified as LSTC other than pursuant to applicable U.S. Bankruptcy Court orders. As a result, for the three months ended September 30, 2007 and 2006, our actual interest payments to unrelated parties were less by $61 million and $192 million, respectively, and for the nine months ended September 30, 2007 and 2006, were less by $139 million and $352 million, respectively, than the contractually specified interest payments (at non-default rates) would have been.

As a result of our Chapter 11 filings and the other matters described herein, including uncertainties related to the fact that we have not yet had time to obtain confirmation of a plan or plans of reorganization, there is substantial doubt about our ability to continue as a going concern. Our ability to continue as a going concern, including our ability to meet our ongoing operational obligations, is dependent upon, among other things: (i) our ability to maintain adequate cash on hand; (ii) our ability to generate cash from operations; (iii) the cost, duration and outcome of our restructuring process; (iv) our ability to comply with the terms of our existing financing obligations and anticipated exit financing and the adequate assurance provisions of the Cash Collateral Order; and (v) our ability to achieve profitability following a restructuring. These challenges are in addition to those operational and competitive challenges faced by us in connection with our business. In conjunction with our advisors, we have implemented and continue to implement strategies to aid our liquidity and our ability to continue as a going concern. However, there can be no assurance as to the success of such efforts.

DIP Facility — On March 29, 2007, we completed the refinancing of the Original DIP Facility with our $5.0 billion DIP Facility. The DIP Facility consists 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 permits us to raise up to $2.0 billion of incremental term loan funding on a senior secured basis with the same priority as the current debt under the DIP Facility. The DIP Facility is priced at LIBOR plus 2.25% or base rate plus 1.25% and matures on the earlier of the effective date of a confirmed plan or plans of reorganization or March 29, 2009. We have the option to convert the DIP Facility into our exit financing, provided certain conditions are met, which would extend the maturity date to March 29, 2014. We expect the effective date of our Plan of Reorganization will be within the next twelve months; therefore, borrowings under the DIP Facility are classified as current at September 30, 2007. In addition to refinancing the Original DIP Facility, borrowings under the DIP Facility were applied on March 29, 2007, to the repayment of the approximately $2.5 billion outstanding principal amount of CalGen Secured Debt (see "— Repayment of CalGen Secured Debt" below). In connection with the refinancing of our Original DIP Facility, we incurred transaction costs of $52 million which are included in reorganization items on our Consolidated Condensed Statements of Operations.

On July 11, 2007, the U.S. Bankruptcy Court authorized us to enter into a commitment letter to fund additional credit facilities, pay associated commitment and other fees, and to amend the DIP Facility to provide for additional secured exit financing of up to $3.0 billion in addition to amounts currently available under the DIP Facility upon conversion of the DIP Facility to exit financing, for a total of $8.0 billion. The amendment of the DIP Facility is subject to further conditions, including obtaining necessary approvals of lenders under the DIP Facility. The commitment to fund the additional facilities under the amended DIP Facility will expire on January 31, 2008, if certain conditions, including effectiveness of the Plan of Reorganization, are not met. In connection with the commitment letter to fund this additional exit financing, we incurred transaction costs of $22 million which are included in reorganization items on our Consolidated Condensed Statements of Operations.

The DIP Facility contains restrictions on the U.S. Debtors, including limiting their ability to, among other things: (i) incur additional indebtedness; (ii) create or incur liens to secure debt; (iii) lease, transfer or sell assets or use proceeds of permitted asset leases, transfers or sales; (iv) issue capital stock; (v) make investments; and (vi) conduct certain types of business.

Our ability to utilize the DIP Facility is subject to the DIP Order. Subject to the exceptions set forth in the DIP Order, the obligations of the U.S. Debtors under the DIP Facility are an allowed administrative expense claim in each of the loan parties' Chapter 11 cases, and are collateralized by (i) a perfected first priority lien on, and security interest in, all present and after-acquired property of the U.S. Debtors not subject to a valid, perfected and non-avoidable lien in existence on the Petition Date or to a valid lien in existence on the Petition Date and subsequently perfected (excluding rights in avoidance actions), (ii) a perfected junior lien on, and security interest in, all present and after-acquired property of the U.S. Debtors that is otherwise subject to a valid, perfected and non-avoidable lien in existence on the Petition Date or a valid lien in existence on the Petition Date that is subsequently perfected and (iii) to the extent applicable, a perfected first priority priming lien on, and security interest in, all present and after-acquired property of the U.S. Debtors that is subject to the replacement liens granted pursuant to and under the Cash Collateral Order.

As of September 30, 2007, there was $4.0 billion outstanding under the term loan facility, no borrowings outstanding under the revolving credit facility and $219 million of letters of credit issued against the revolving credit facility.

Repayment of CalGen Secured Debt — On March 29, 2007, we repaid the approximately $2.5 billion outstanding principal amount of CalGen Secured Debt, primarily with borrowings under the DIP Facility term loan facility plus approximately $224 million of cash on hand at CalGen. To effectuate the repayment of the CalGen Secured Debt, the U.S. Debtors requested that the U.S. Bankruptcy Court allow the U.S. Debtors' limited objection to claims filed by the holders of the CalGen Secured Debt. The U.S. Bankruptcy Court granted the U.S. Debtors' limited objection in part, finding that the CalGen Secured Debt lenders were not entitled to a secured claim for a pre-payment premium under the CalGen loan documents. However, the U.S. Bankruptcy Court granted the CalGen Secured Debt lenders an unsecured claim for damages. Specifically, the U.S. Bankruptcy Court held that (i) the holders of the CalGen First Lien Debt are entitled to an unsecured claim for damages in the amount of 2.5% of the outstanding principal, (ii) the holders of the CalGen Second Lien Debt are entitled to an unsecured claim for damages in the amount of 3.5% of the outstanding principal, and (iii) the holders of the CalGen Third Lien Debt are entitled to an unsecured claim for damages in the amount of 3.5% of the outstanding principal. As a result of the DIP Order and repayment of CalGen Secured Debt, we recorded expense of $32 million to write off the remaining unamortized discount and deferred financing costs and recorded $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. These expenses are included in reorganization items on our Consolidated Condensed Statements of Operations for the nine months ended September 30, 2007. Both we and the holders of the CalGen Secured Debt have appealed the DIP Order to the SDNY Court. In this appeal, the holders of the CalGen Secured Debt are arguing for larger, secured damages claims and we are arguing that no damages should arise in connection with the repayment of the CalGen Secured Debt. We are seeking permission from the U.S. Bankruptcy Court to amend our Plan of Reorganization to pay the damages, if any, awarded to the holders of the CalGen Secured Debt in full and in cash or cash equivalents in the amount ultimately determined on appeal by a final order, regardless of whether such claims are deemed secured or remain unsecured. The holders of the CalGen Secured Debt are also seeking interest on their claims at the default rate. The U.S. Bankruptcy Court concluded that a decision on default interest was premature. Accordingly, we have not accrued any default interest for the CalGen Secured Debt as of September 30, 2007. Under the CalGen Secured Debt agreements, the lenders could receive additional default interest of 1% on the CalGen Notes and 2% on the CalGen Term Loans from December 21, 2005, through March 29, 2007.

Cash Management — We have received U.S. Bankruptcy Court approval to continue to manage our cash in accordance with our pre-existing intercompany cash management system during the pendency of the Chapter 11 cases. This program allows us to maintain bank and other investment accounts and to continue to manage our cash on an integrated basis through Calpine Corporation. Such cash management systems are subject to the requirements of the DIP Facility, the Cash

Collateral Order and the 345(b) Waiver Order. Pursuant to the cash management system, and in accordance with our cash collateral requirements in connection with the DIP Facility and relevant U.S. Bankruptcy Court orders, intercompany transfers are generally recorded as intercompany loans. Upon the closing of the DIP Facility, the cash balances of the U.S. Debtors (each of whom is a participant in the cash management system), which had been subject to a lien in favor of the Original DIP Facility lenders, became subject to security interests in favor of the DIP Facility lenders. The DIP Facility provides that all unrestricted cash of the U.S. Debtors and certain other subsidiaries exceeding a $25 million threshold be maintained in a concentration account with one of the DIP Facility agents. In addition, the DIP Facility provides that the DIP Facility agent may elect to require all unrestricted cash of the U.S. Debtors and certain other subsidiaries, including amounts below the $25 million threshold, be maintained in the concentration account.

In addition, during the pendency of our Chapter 11 cases, in lieu of distributions, our U.S. Debtor subsidiaries are 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.

Off Balance Sheet Commitments of Unconsolidated Subsidiaries — The following describes the debt on the books of our unconsolidated subsidiaries which is not reflected on our Consolidated Condensed Balance Sheets.

On May 3, 2007, OMEC entered into a $377 million non-recourse project finance facility to finance the construction of the Otay Mesa Energy Center, a 596-MW natural gas-fired power plant under construction in southern San Diego County, California. 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%.

On May 31, 2007, Greenfield LP entered into a Can$648 million non-recourse project finance facility to finance the construction of the Greenfield Energy Centre, a 1,005-MW natural gas-fired power plant currently under construction in St. Clair Township, Ontario, Canada. Greenfield LP is a limited partnership between certain subsidiaries of ours and of Mitsui & Co., Ltd. We and Mitsui & Co., Ltd. each hold a 50% interest in Greenfield LP. The project finance facility 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 LIBOR plus 1.2% or prime rate plus 0.2%.

Cash Flow Activities — The following table summarizes our cash flow activities for the periods indicated (in millions):

	Nine Months Ended September 30,	
	2007	2006
Beginning cash and cash equivalents	$ 1,077	$ 786
Net cash provided by (used in):		
Operating activities	93	167
Investing activities	483	(46)
Financing activities	50	100
Net increase in cash and cash equivalents including discontinued operations cash	626	221
Change in discontinued operations cash classified as assets held for sale	—	(18)
Net increase in cash and cash equivalents	626	203
Ending cash and cash equivalents	$ 1,703	$ 989

Cash flows from operating activities for the nine months ended September 30, 2007, resulted in net inflows of $93 million compared to net inflows of $167 million in the same period in 2006. This decrease in net inflows was primarily due to a $154 million increase in cash paid for interest resulting from the payment of additional adequate protection payments on our Second Priority Debt during 2007. The increase in interest payments was partially offset by an increase in income from operations for the nine months ended September 30, 2007, as compared to the same period in 2006. See "— Results of Operations for the Nine Months Ended September 30, 2007" for a discussion of changes in the components of our income from operations and interest expense period over period.

Cash flows from investing activities for the nine months ended September 30, 2007, resulted in net inflows of $483 million, as compared to net outflows of $46 million for the same period in 2006, an increase of $529 million. The increase in cash flows from investing activities was largely the result of proceeds from asset sales in 2007 of $507 million compared to $38 million 2006. Asset sales in 2007 included PSM, the Aries Power Plant, the Goldendale Energy Center, the Parlin Power Plant and our 50% ownership interest in Acadia PP. Also contributing to the increase in cash flows from investing activities for the nine months ended September 30, 2007, was a total return of investment of $179 million in Greenfield LP and the Canadian Debtors. The net inflows during 2007 were partially offset by a $385 million decrease in the net reduction of restricted cash to $57 million for the nine months ended September 30, 2007, from $442 million for the same period in 2006. The decrease in restricted cash during the nine months ended September 30, 2006, was primarily due to the repayment of the First Priority Notes. The increase in cash and cash equivalents resulting from the decrease in restricted cash during 2006 was partially offset by outflows of $267 million for the purchase of the Geysers Assets.

Cash flows from financing activities for the nine months ended September 30, 2007, resulted in net inflows of $50 million, as compared to net inflows of $100 million for the same period in 2006. This decrease in net inflows is primarily due to a reduction in our net borrowings of $29 million and an increase in our financing costs of $47 million during the nine months ended September 30, 2007, as compared to the same period in 2006. The increase in our financing costs is due to an $18 million increase in costs related to our DIP Facility, $22 million in transaction costs during 2007 related to the execution of a commitment letter to fund our additional exit financing and an increase of $6 million in project financing costs.

Negative Working Capital — At September 30, 2007, we had negative working capital of $2.3 billion which is primarily due to the classification of $4.0 billion of borrowings under the DIP Facility as current because we expect the effective date of our Plan of Reorganization will be within the next twelve months. Additionally, defaults under certain of our indentures and other financing instruments required us to record approximately $677 million of debt as current that otherwise would have been recorded as non-current. Generally, we are seeking waivers or other resolutions with respect to the defaults in the case of Non-Debtor entities. With respect to the Calpine Debtor entities, such obligations may have been accelerated due to such defaults, but generally, all actions to enforce or otherwise effect repayment of liabilities preceding the Petition Date are stayed in accordance with the Bankruptcy Code or orders of the Canadian Court, as applicable, while the Calpine Debtors continue their business operations as debtors-in-possession. See Note 7 of the Notes to Consolidated Condensed Financial Statements for further discussion of our debt, lease and indenture covenant compliance.

Letter of Credit Facilities — At September 30, 2007, and December 31, 2006, we had $369 million and $264 million, respectively, in letters of credit outstanding under various credit facilities to support our risk management and other operational and construction activities.

Commodity Margin Deposits and Other Credit Support — As of September 30, 2007, and December 31, 2006, to support commodity transactions, we had margin deposits with third parties of $249 million and $214 million, respectively; we had gas and power prepayment balances of $86 million and $114 million, respectively; and had letters of credit outstanding of $35 million and $2 million, respectively, which are included in the letter of credit facilities discussed above. Counterparties had margin deposits with us of $41 million and nil at September 30, 2007, and December 31, 2006, respectively. In addition, we have granted additional first priority liens on the assets currently subject to first priority liens under the DIP Facility as collateral under certain of our power agreements, natural gas agreements and interest rate swap agreements that qualify as "eligible commodity hedge agreements" under the DIP Facility 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 DIP Facility. As of September 30, 2007, and December 31, 2006, our net discounted exposure under the power and natural gas agreements collateralized by such first priority liens was approximately $4 million and nil, respectively, and our net discounted exposure under the interest rate swap agreements collateralized by such first priority liens was approximately $51 million and nil, respectively.

We use margin deposits, first priority liens (as described above), prepayments and letters of credit as credit support for commodity procurement and risk management activities. Future cash collateral and first priority lien requirements 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 this 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 — A significant component of our restructuring activities has been to conserve our core strategic assets and selectively dispose of certain less strategically important assets. Since the Petition Date, pursuant to the Cash Collateral Order, we agreed that we would limit the amount of funds available to support the operations of 14 designated projects. These designated projects were: Acadia Energy Center, Aries Power Plant, Clear Lake Power Plant, Dighton Power Plant, Fox Energy Center, Pryor Power Plant, Newark Power Plant, Parlin Power Plant, Pine Bluff Energy Center, Hog Bayou Energy Center, Rumford Power Plant, Santa Rosa Energy Center, Texas City Power Plant and Tiverton Power Plant. In accordance with the Cash Collateral Order, it is possible that additional power plants will be added (or certain of the listed plants may be removed) as designated projects. As of the filing of this Report, five of the 14 designated projects have been sold (Acadia, Aries, Dighton, Fox and Parlin), two (Rumford and Tiverton) have been turned over to a receiver appointed by the SDNY Court following our rejection of the related power plant leases and surrender of the facilities and, at five of the projects (Texas City, Clear Lake, Pine Bluff, Hog Bayou and Santa Rosa), we have restructured agreements or reconfigured equipment such that continued operation of the facilities is merited, although eventual sale remains a possibility. As a result of these actions, each of Aries Power Plant, Clear Lake Power Plant, Dighton Power Plant, Fox Energy Center, Rumford Power Plant, Texas City Power Plant and Tiverton Power Plant were removed from the list of designated projects. We have not yet determined what actions we will take with respect to other designated projects; however, it is possible that we could seek to sell our interests in those facilities or, as applicable, reject the related leases.

During the nine months ended September 30, 2007, and through the filing of this Report, we have taken the following actions with respect to sales of our designated projects:

- On January 16, 2007, we completed the sale of the Aries Power Plant, a 590-MW natural gas-fired power plant in Pleasant Hill, Missouri, to Dogwood Energy LLC, an affiliate of Kelson Holdings, LLC for $234 million, plus certain per diem expenses incurred by us for running the power plant after December 21, 2006, through the closing of the sale. We recorded a pre-tax gain of approximately $78 million during the first quarter of 2007. As part of the sale we were also required to use a portion of the proceeds received to repay approximately $159 million principal amount of financing obligations, $8 million in accrued interest, $11 million in accrued swap liabilities and $14 million in debt pre-payment and make whole premium fees to our project lenders.

- On July 6, 2007, we completed the sale of the Parlin Power Plant, a 118-MW natural gas-fired power plant in Parlin, New Jersey, to EFS Parlin Holdings, LLC, an affiliate of General Electric Capital Corporation, for approximately $3 million in cash, plus the assumption by EFS Parlin Holdings, LLC of certain liabilities and the agreement to waive certain asserted claims against the Parlin Power Plant. We recorded a pre-tax gain of approximately $40 million during the three months ended September 30, 2007.

- On September 13, 2007, we completed the sale of our 50% ownership interest in Acadia PP, the owner of the Acadia Energy Center, a 1,212-MW natural gas-fired power plant located near Eunice, Louisiana, to Cajun Gas Energy, L.L.C. for consideration totaling approximately $189 million consisting of $104 million in cash and the payment of $85 million in priority distributions due to Cleco (the indirect owner, through its subsidiary APH, of the remaining 50% ownership interest in Acadia PP) in accordance with the limited liability company agreement, plus the assumption by Cajun Gas Energy, L.L.C. of certain liabilities. We recorded a pre-tax loss of $6 million during the three months ended September 30, 2007, after having recorded a pre-tax, predominately non-cash impairment charge of approximately $89 million during the second quarter of 2007, to record our interest in Acadia PP at fair value less cost to sell, both of which charges are included in reorganization items on our Consolidated Condensed Statements of Operations. Additionally, in connection with the sale, we entered into a settlement agreement with Cleco, which was approved by the U.S. Bankruptcy Court on May 9, 2007, under which Cleco received an allowed unsecured claim against us in the amount of $85 million as a result of the rejection by CES of two long-term PPAs for the output of the Acadia Energy Center and our guarantee of those agreements. We recorded expense of $85 million for this allowed claim during the second quarter of 2007, which is included in reorganization items on our Consolidated Condensed Statements of Operations.

In addition to the sales of our designated projects, the following asset sale activities have also taken place during the nine months ended September 30, 2007, and through the filing of this Report:

- On February 21, 2007, we completed the sale of substantially all of the assets of the Goldendale Energy Center, a 247-MW natural gas-fired power plant located in Goldendale, Washington, to Puget Sound Energy LLC for approximately $120 million, plus the assumption by Puget Sound of certain liabilities. We recorded a pre-tax gain of approximately $31 million during the first quarter of 2007.

- On March 22, 2007, we completed the sale of substantially all of the assets of PSM, a designer, manufacturer and marketer of turbine and combustion components, to Alstom Power Inc. for approximately $242 million, plus the assumption by Alstom Power Inc. of certain liabilities. In connection with the sale, we entered into a parts supply and development agreement with PSM whereby we have committed to purchase turbine parts and other services totaling approximately $200 million over a five-year period. Additionally, we recorded a pre-tax gain of $135 million during the first quarter of 2007 as the risks and other incidents of ownership were transferred to Alstom Power Inc.

Chapter 11 Claims Assessment — Our Consolidated Condensed Financial Statements include, as liabilities subject to compromise, certain pre-petition liabilities recorded on our Consolidated Condensed Balance Sheet as of the Petition Date and subsequent estimates of expected allowed claims relating to rejected and repudiated contracts, guarantees, litigation, accounts payable and accrued liabilities, debt and other liabilities. We expect that our estimates, although based on the best available information, will change due to actions of the U.S. Bankruptcy Court, negotiations, rejection or repudiation of executory contracts and unexpired leases, and the determination as to the value of any collateral securing claims, proofs of claim or other events.

The following table summarizes the claims in our Chapter 11 cases as of September 30, 2007:

	Total Number Of Claims	Total Claims Exposure (in millions)
Total claims filed	18,467	$ 111,740
Less:		
Disallowed and expunged claims		72,159
Withdrawn claims		8,127
Redundant claims		1,049
Other claims with basis for objection or reduction		18,888
Total estimate of liquidated claims exposure		$ 11,517
Amounts recorded as liabilities not subject to compromise		184
Total estimate of liquidated claims exposure (net of amounts not subject to compromise)		$ 11,333

Of the approximately $11.5 billion of filed and scheduled liquidated claims, we have recorded approximately $184 million as liabilities not subject to compromise and approximately $11.7 billion as LSTC on our Consolidated Condensed Balance Sheet as of September 30, 2007. The difference between the total estimated liquidated claims exposure (net of amounts not subject to compromise) and LSTC is approximately $334 million and primarily relates to claims in process of reconcilement, claims for unliquidated amounts and scheduled amounts where no claims have been filed.

During the nine months ended September 30, 2007, and through the filing of this Report, we have settled the following significant claims:

- On July 30, 2007, we entered into the Canadian Settlement Agreement after the Bankruptcy Courts approved the terms of our two previously disclosed proposed settlements with the Canadian Debtors and with an ad hoc committee of holders of notes issued by our subsidiary ULC I and guaranteed by Calpine Corporation. The Canadian Settlement Agreement, which encompasses both proposed settlements, resolves virtually all major cross-border issues among the parties relating to pre-petition intercompany balances, our direct and indirect guarantees of the ULC I notes and our guarantee of the ULC II notes and related interest. The material contingencies within the Canadian Settlement Agreement were resolved by September 30, 2007. As a result, the provision for expected allowed claims in reorganization items was reduced by approximately $4.1 billion and interest expense was increased by approximately $0.3 billion on our Consolidated Condensed Statements of Operations during the three months ended September 30, 2007.

- On August 8, 2007, the U.S. Bankruptcy Court approved a settlement with the Ad Hoc Committee of Second Lien Holders of Calpine Corporation and Wilmington Trust Company as indenture trustee for the Second Priority Notes. Pursuant to the settlement, approximately $289 million of claims for make whole premiums and/or damages asserted against the U.S. Debtors by the holders of the Second Priority Debt will be replaced by a secured claim for $60 million that shall be paid in cash and an unsecured claim for $40 million. As a result, we recorded expense of $100 million to the provision for expected allowed claims in reorganization items on our Consolidated Condensed Statements of Operations during the three months ended September 30, 2007.

- On August 10, 2007, the U.S. Bankruptcy Court approved our limited objection to certain claims asserted by holders of the Convertible Notes, disallowing claims seeking damages for alleged breach of “conversion rights.” The U.S. Bankruptcy Court’s decision does not affect a previous agreement to allow claims for repayment of principal and interest on the Convertible Notes.

- On October 10, 2007, the U.S. Bankruptcy Court approved the settlement agreement with the Unsecured Noteholders and the indenture trustee for such Unsecured Notes. Under the agreement, $109 million of claims for make whole premiums asserted against the U.S. Debtors were replaced with unsecured claims totaling $54 million. In addition, the U.S. Debtors have agreed to pay the reasonable professional fees incurred by the Unsecured Noteholders and the indenture trustee. As a result, we recorded expense of $54 million to the provision for expected allowed claims in reorganization items on our Consolidated Condensed Statements of Operations during the three months ended September 30, 2007.

Debt, Lease and Indenture Covenant Compliance — See Note 7 of the Notes to Consolidated Condensed Financial Statements for compliance information.

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, Gilroy Energy Center, LLC, Calpine Gilroy Cogen, L.P., Calpine Gilroy 1, Inc., King City Cogen, Calpine Securities Company, L.P. (a parent company of King City Cogen), Calpine King City, LLC (an indirect parent company of Calpine Securities Company, L.P.), Calpine Deer Park Partner, LLC, Calpine DP, LLC, Deer Park, CCFCP, Metcalf and Russell City Energy Company, LLC.

Recent Regulatory Developments

Since the filing of our 2006 Form 10-K, the following significant regulatory developments have occurred:

U.S. Supreme Court Case Regarding Regulation of GHG

On April 2, 2007, the U.S. Supreme Court issued a decision in Commonwealth of Massachusetts v. EPA, finding in favor of the Commonwealth of Massachusetts that the CAA requires the EPA to regulate GHG from new motor vehicles once the EPA concludes that such emissions contribute to climate change. In doing so, the U.S. Supreme Court reversed the lower court's ruling and remanded the case for further proceedings. We had submitted an *amicus curiae* brief in support of the position of the Commonwealth of Massachusetts, arguing that the U.S. Supreme Court's ruling would effectively determine the EPA's authority to regulate air pollution associated with climate change from all sources, including power plants. We do not know at this time what further action the lower court or the EPA will take in response to the U.S. Supreme Court's ruling, or how it may ultimately affect us or our industry. Our general position with respect to these laws attempts to take advantage of our relatively clean portfolio of power plants as compared to our competitors.

NERC Compliance Requirements

Pursuant to the Energy Policy Act of 2005, FERC certified NERC as the ERO to develop mandatory and enforceable electric system reliability standards applicable throughout the U.S., which are subject to FERC review and approval. Once approved, the reliability standards may be enforced by FERC independently, or, alternatively, by the ERO and regional reliability organizations with frontline responsibility for auditing, investigating and otherwise ensuring compliance with reliability standards, subject to FERC oversight. In March 2007, FERC approved 83 reliability standards that became enforceable as of June 18, 2007, and additional ones are pending finalization. All owners, operators, and users of the bulk electric system, including us, are required to comply. Monetary penalties of up to $1 million per day per violation may be assessed for violations of the reliability standards. We have submitted to the regional reliability organizations self-reports of potential violations of an administrative nature that existed prior to the June 18, 2007, mandatory effective date, and NERC has stated that such pre-existing violations would not be subject to penalties as long as mitigation plans are in place to remedy those violations. We have submitted mitigation plans with all regional reliability organizations in which we operate outlining our plan to achieve full compliance before the end of 2007. We will continue to use best efforts to comply with all applicable reliability standards, but because this regulatory program is new, there is no precedent for how the reliability standards and enforcement regime may affect us or our assets.

Financial Market Risks

As we are primarily focused on the generation of electricity using gas-fired turbines, our natural physical commodity position is "short" fuel (*i.e.*, natural gas consumer) and "long" power (*i.e.*, electricity seller). To manage forward exposure to price fluctuation in these and (to a lesser extent) other commodities, we enter into derivative commodity instruments.

The change in fair value of outstanding commodity derivative instruments from January 1, 2007, through September 30, 2007, is summarized in the table below (in millions):

Fair value of commodity contracts outstanding at January 1, 2007	$	(202)
(Gains) losses recognized or otherwise settled during the period[1]		81
Fair value attributable to new contracts		(75)
Changes in fair value attributable to price movements		26
Fair value of commodity contracts outstanding at September 30, 2007[2]	$	(170)

(1) Recognized gains from commodity cash flow hedges of $5 million (represents a portion of the realized value of cash flow hedge activity of $7 million as disclosed in Note 8 of the Notes to Consolidated Condensed Financial Statements) net of losses related to the terminated fair value hedged item of $54 million (represents a portion of sales of purchased power as reported on our Consolidated Condensed Statements of Operations) and losses related to undesignated derivatives of $32 million (represents a portion of the realized mark-to-market activities, net as reported on our Consolidated Condensed Statements of Operations).

(2) Net commodity derivative liabilities reported in Note 8 of the Notes to Consolidated Condensed Financial Statements.

Of our total mark-to-market gain of $2 million and $5 million for the three and nine months ended September 30, 2007, we had unrealized losses of $(8) million and $(16) million, respectively, and we had realized gains of $10 million and $21 million, respectively. The realized portion included non-cash gains of approximately $22 million and $43 million from amortization of various items for the three and nine months ended September 30, 2007, respectively.

The fair value of outstanding derivative commodity instruments at September 30, 2007, based on price source and the period during which the instruments will mature, are summarized in the table below (in millions):

Fair Value Source	2007	2008-2009	2010-2011	After 2011	Total
Prices actively quoted	$ (39)	$ 12	$ —	$ (10)	$ (37)
Prices provided by other external sources	21	(62)	(92)	—	(133)
Total fair value	$ (18)	$ (50)	$ (92)	$ (10)	$ (170)

Our risk managers maintain fair value price information derived from various sources in our risk management systems. The propriety of that information is validated by our risk control group. Prices actively quoted include those sourced from commodities exchanges (e.g., New York Mercantile Exchange). Prices provided by other external sources include quotes from commodity brokers and electronic trading platforms.

The counterparty credit quality associated with the fair value of outstanding derivative commodity instruments at September 30, 2007, 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 September 30, 2007)	2007	2008-2009	2010-2011	After 2011	Total
Investment grade	$ 14	$ 328	$ (54)	$ (10)	$ 278
Non-investment grade	(2)	(2)	—	—	(4)
No external ratings	(30)	(376)	(38)	—	(444)
Total fair value	$ (18)	$ (50)	$ (92)	$ (10)	$ (170)

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

	Fair Value	Fair Value After 10% Adverse Price Change
At September 30, 2007:		
Electricity	$ (36)	$ (288)
Natural gas	(134)	(299)
Total	$ (170)	$ (587)

Derivative commodity instruments included in the table are those included in Note 8 of the Notes to Consolidated Condensed Financial Statements. The fair value of derivative commodity instruments included in the table is based on present value-adjusted quoted market prices of comparable contracts. The fair value of electricity derivative commodity instruments after a ten percent adverse price change includes the effect of increased power prices versus our derivative forward commitments. Conversely, the fair value of the natural gas derivatives after a ten percent adverse price change reflects a general decline in gas prices versus our derivative forward commitments. Derivative commodity instruments offset the price risk exposure of our physical assets. None of the offsetting physical positions are included in the table above.

Price changes were calculated by assuming an across-the-board ten percent adverse price change regardless of term or historical relationship between the contract price of an instrument and the underlying commodity price. In the event of an actual ten percent change in prices, the fair value of our derivative portfolio would typically change by more than ten percent for earlier forward months and less than ten percent for later forward months because of the higher volatilities in the near term and the effects of discounting expected future cash flows.

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 a negative 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.

Our risk management policy allows us to enter into a variety of derivative instruments to mitigate our exposure to interest rate fluctuations. Currently, we use interest rate swaps to adjust the mix between fixed and floating rate debt to hedge interest rates. We do not use interest rate derivative instruments for speculative or trading purposes. Our interest rate swaps are cash flow hedges and changes in fair value are recorded in OCI to the extent they are effective.

The following table summarizes the expected maturity of the carrying amounts, weighted average interest rates and fair values for our debt obligations as well as the notional amounts, weighted average interest rates and fair values for our interest rate swaps. The notional amounts of our interest rate swaps are used to calculate the cash flows to be exchanged under the swap agreements. The information presented is as of September 30, 2007 (dollars in millions).

	2007	2008	2009	2010	2011	Thereafter	Total	Fair Value September 30, 2007
Debt:								
Fixed rate	$ 15	$ 206	$ 218	$ 253	$ 125	$ 820	$ 1,637	$ 1,608
Average interest rate	9.5%	6.9%	7.1%	7.7%	9.0%	9.4%		
Variable rate	$ 13	$ 3,991	$ 382	$ 272	$ 1,697	$ 46	$ 6,401	$ 6,396
Average interest rate	7.5%	7.3%	11.0%	11.5%	10.6%	10.8%		
Interest Rate Instruments:								
Variable to fixed swaps(1)	$ 5,892	$ 5,892	$ 5,592	$ 3,411	$ 1,811	$ 1,580	n/a	$ (55)
Average pay rate	5.0%	5.0%	5.0%	5.2%	4.9%	4.9%		
Average receive rate	5.2%	4.9%	4.7%	4.7%	4.8%	4.9%		

(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 at the reasonable assurance level. Management believes that the financial statements included in this Report fairly present in all material respects our financial condition, results of operations and cash flows for the periods presented. The certificates required by this Item are filed as Exhibits 31.1 and 31.2 to this Report.

Substantive Consolidation

As disclosed in our Disclosure Statement filed with the U.S. Bankruptcy Court, our Plan of Reorganization contemplates substantive consolidation of the estates of Calpine and its U.S. Debtor subsidiaries. In bankruptcy cases with affiliated debtors, a bankruptcy court may exercise its equitable powers to authorize the “substantive consolidation” of the estates of affiliated debtors for purposes of the plan of reorganization. Substantive consolidation involves the pooling of assets and liabilities of the affected debtors to effectively treat them as single corporate entity. The determination to substantively consolidate, in this circumstance, depends in part on whether the affairs of the debtors are so entangled that the consolidation will benefit all creditors. After arduous due diligence performed by counsel and financial advisors it was our view that certain of the controls over intercompany accounting, controls that help ensure that intercompany transactions are recorded accurately and can be reconciled, were not operating effectively. Due to the ineffectiveness of certain of the controls over intercompany transactions, we relied on the following compensating controls, which operated at a level of precision that would prevent or detect a misstatement that could be material to the Company:

- The Company’s procedures require all intercompany transactions to be recorded in standardized “affiliate” accounts which are for the exclusive use of recording intercompany transactions, and the balances in such accounts are properly eliminated in consolidation. To ensure that intercompany balances have properly eliminated, “Intercompany Out-of-Balance” reports are run daily during the monthly closing process and distributed to all accountants at the Company to identify and correct any out-of-balance occurrences in each affiliate account.

- To provide reasonable assurance that no intercompany transactions have inadvertently been recorded in accounts set aside for transactions with third parties, the Company performs an analysis of each account with third party balances during the quarterly closing process. These analyses are reviewed by the Company’s accounting management.

In addition to the recurring compensating controls above, subsequent to the Company’s bankruptcy filing, the Company undertook an initiative to review its consolidation process to ensure that all intercompany related transactions eliminated upon consolidation. This review included all intercompany and investment-in-affiliate accounts. Based on this review, the Company’s management team was satisfied that all intercompany account balances are eliminated upon consolidation.

In the implementation of the compensating or mitigating controls, we took into account whether the controls adequately address the risks that a material misstatement of the consolidated financial statements would be prevented or detected in a timely manner. As stated above we concluded that our disclosure controls and procedures were operating at the reasonably effective level. By reasonable assurance we mean a level of detail and degree of assurance that would satisfy a prudent official in the conduct of their own affairs.

Changes in Internal Controls Over Financial Reporting

During the third quarter of 2007, 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 10 of the Notes to Consolidated Condensed Financial Statements for a description of our legal proceedings.

Item 3. ***Defaults Upon Senior Securities.***

See Note 7 of the Notes to Consolidated Condensed Financial Statements for a description of defaults under our indebtedness.

See also Note 2 of the Notes to Consolidated Condensed Financial Statements for our liabilities subject to compromise, which sets forth the amounts of our indebtedness classified as LSTC. We are no longer paying current interest on any LSTC other than pursuant to applicable U.S. Bankruptcy Court orders. In particular, pursuant to orders of the U.S. Bankruptcy Court, we will make adequate protection payments on the Second Priority Debt through December 31, 2007. Those orders provide that the Second Priority Debt must seek further orders from the U.S. Bankruptcy Court for any further amounts to be paid thereafter. We have not yet made a determination as to whether any portion of the adequate protection payments represents payment of principal and have, therefore, reported the full amount of the adequate protection payments as interest expense on our Consolidated Condensed Statements of Operations. We continue to make current payments of interest and, if applicable, principal on all debt of Non-U.S. Debtor entities, including debt under which there are defaults.

Item 5. ***Other Information.***

Modifications of Robert P. May Employment Agreements. On October 10, 2007, the U. S. Bankruptcy Court approved the amendment of Mr. May's Employment Agreement to extend the term of the Employment Agreement from December 31, 2007 to June 30, 2008. The amendment also provides that if we and Mr. May are unable to negotiate, prior to the end of the term, a new employment arrangement to take effect no later than July 1, 2008, then Mr. May's employment shall terminate on June 30, 2008, and (a) subject to his providing a release in accordance with the Employment Agreement, Mr. May shall be entitled to receive certain severance benefits described in the Employment Agreement as if his employment had been terminated by us without Cause on June 30, 2008, and (b) if such termination is prior to the date on which the Success Fee is earned and paid pursuant to the Employment Agreement, Mr. May shall be eligible to earn the Success Fee or the Guaranteed Minimum Success Fee in accordance with the provisions of the Employment Agreement, as if his employment had been terminated by us without Cause on June 30, 2008.

Emergence Incentive Plan. Under our Emergence Incentive Plan, a select group of members of our senior management team, including certain of our executive officers, are eligible for a cash bonus upon our emergence from Chapter 11 to be allocated at the sole discretion of our Chief Executive Officer, Mr. Robert May. At this time, the amount of the emergence bonus is unknown; however, Mr. May has established certain minimum percentage participation allocations for certain participants in the Emergence Incentive Plan. Pursuant to such allocations, Mr. Gregory Doody, a participant in the Emergence Incentive Plan and one of our Named Executive Officers, will receive a minimum of 16% of the Emergence Incentive Plan pool.

Corporate Aircraft Policy. We arrange for private aircraft to be available for business use by our directors and certain of our Named Executive Officers through a flexjet program. Our general policy, established in August 2007 and made effective as of May 29, 2007, is not to permit any personal use of such aircraft; however, our guidelines permit non-business related flights on a case-by-case basis for charitable causes, emergency family matters (death, illness, etc.), community service, and disaster relief. In addition, the aircraft may be approved for use for commuting to or from business meetings or our principal offices. Although we consider the costs associated with providing private aircraft a necessary business expense rather than a perquisite, we will disclose amounts attributable to personal use of the aircraft by our directors and Named Executive Officers in accordance with SEC guidelines.

Item 6. ***Exhibits.***

The following exhibits are filed herewith unless otherwise indicated:

EXHIBIT INDEX

Exhibit Number	Description
2.1	Debtors' Fourth Amended Joint Plan of Reorganization Pursuant to Chapter 11 of the United States Bankruptcy Code.*
3.1.1	Amended and Restated Certificate of Incorporation of the Company, as amended (incorporated by reference to Exhibit 3.1 to the Company's Annual Report on Form 10-K for the period ended December 31, 2006, filed with the SEC on March 14, 2007).
3.2	Amended and Restated By-laws of the Company (incorporated by reference to Exhibit 3.1.8 to the Company's Annual Report on Form 10-K for the year ended December 31, 2001, filed with the SEC on March 29, 2002).
10.1	Settlement Agreement dated as of July 24, 2007, by and between Calpine Corporation, on behalf of itself and its U.S. subsidiaries, Calpine Canada Energy Ltd., Calpine Canada Power Ltd., Calpine Canada Energy Finance ULC, Calpine Energy Services Canada Ltd., Calpine Canada Resources Company, Calpine Canada Power Services Ltd., Calpine Canada Energy Finance II ULC, Calpine Natural Gas Services Limited, 3094479 Nova Scotia Company, Calpine Energy Services Canada Partnership, Calpine Canada Natural Gas Partnership, Calpine Canadian Saltend Limited Partnership and HSBC Bank USA, National Association, as successor indenture trustee (incorporated by reference to Exhibit 99.1 to the Company's Current Report on Form 8-K filed with the SEC on August 3, 2007).
10.2	Amendment, dated October 10, 2007, to Employment Agreement between the Company and Robert P. May.*†
10.3	Employment Separation Agreement dated August 31, 2007, between the Company and Eric N. Pryor.*†
10.4	Letter dated September 20, 2007, from the Company to Gregory Doody.*†
10.5	Aircraft Travel Card Guidelines.*†
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/ LISA DONAHUE
Lisa Donahue
Senior Vice President and
Chief Financial Officer

Date: November 6, 2007

By: /s/ CHARLES B. CLARK, JR.
Charles B. Clark, Jr.
Senior Vice President and
Chief Accounting Officer

Date: November 6, 2007

The following exhibits are filed herewith unless otherwise indicated:

EXHIBIT INDEX

Exhibit Number	Description
2.1	Debtors' Fourth Amended Joint Plan of Reorganization Pursuant to Chapter 11 of the United States Bankruptcy Code.*
3.1.1	Amended and Restated Certificate of Incorporation of the Company, as amended (incorporated by reference to Exhibit 3.1 to the Company's Annual Report on Form 10-K for the period ended December 31, 2006, filed with the SEC on March 14, 2007).
3.2	Amended and Restated By-laws of the Company (incorporated by reference to Exhibit 3.1.8 to the Company's Annual Report on Form 10-K for the year ended December 31, 2001, filed with the SEC on March 29, 2002).
10.1	Settlement Agreement dated as of July 24, 2007, by and between Calpine Corporation, on behalf of itself and its U.S. subsidiaries, Calpine Canada Energy Ltd., Calpine Canada Power Ltd., Calpine Canada Energy Finance ULC, Calpine Energy Services Canada Ltd., Calpine Canada Resources Company, Calpine Canada Power Services Ltd., Calpine Canada Energy Finance II ULC, Calpine Natural Gas Services Limited, 3094479 Nova Scotia Company, Calpine Energy Services Canada Partnership, Calpine Canada Natural Gas Partnership, Calpine Canadian Saltend Limited Partnership and HSBC Bank USA, National Association, as successor indenture trustee (incorporated by reference to Exhibit 99.1 to the Company's Current Report on Form 8-K filed with the SEC on August 3, 2007).
10.2	Amendment, dated October 10, 2007, to Employment Agreement between the Company and Robert P. May.*†
10.3	Employment Separation Agreement dated August 31, 2007, between the Company and Eric N. Pryor.*†
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* Filed herewith.

† Management contract or compensatory plan or arrangement.