CALPINE®
NYSE CPN

2008 ANNUAL REPORT

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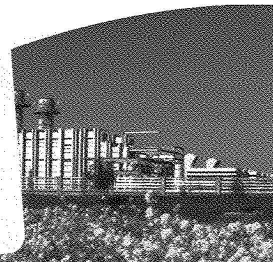
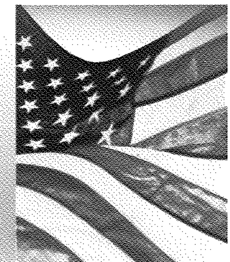
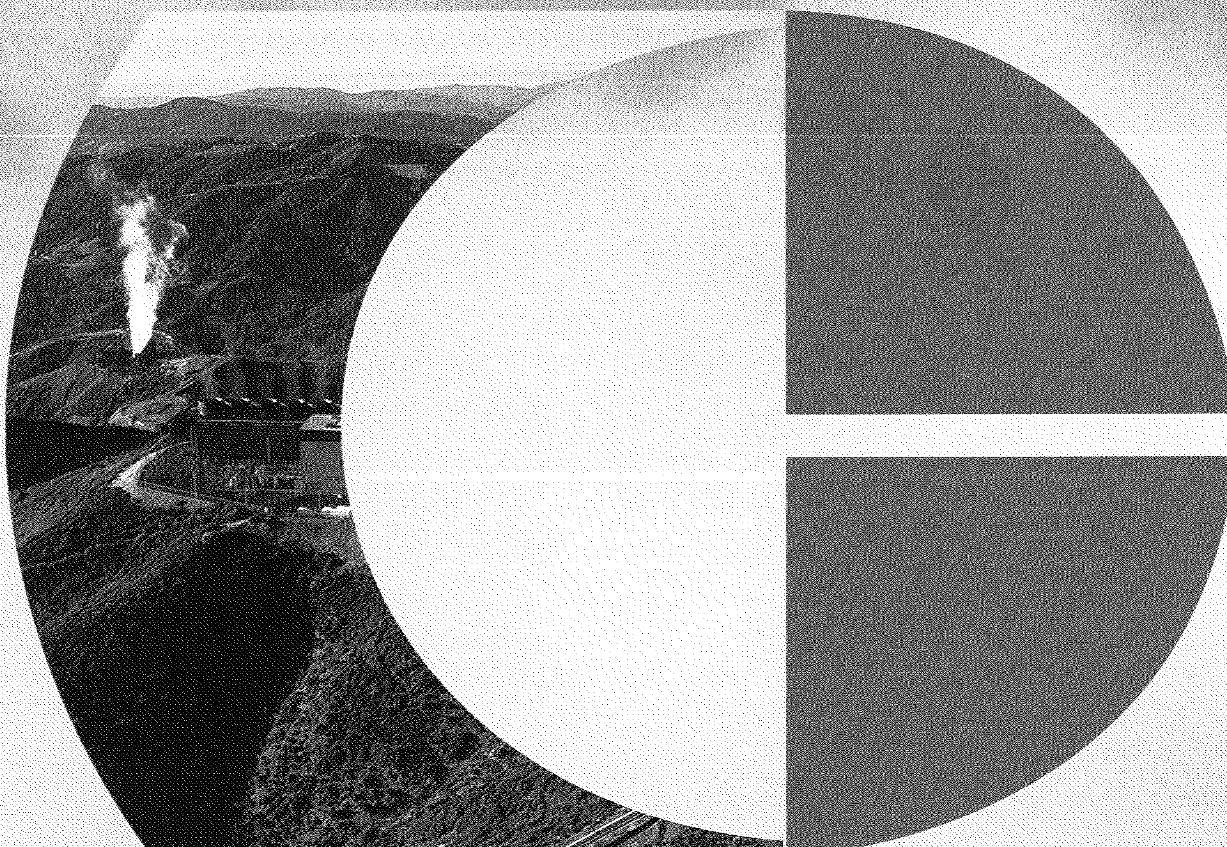
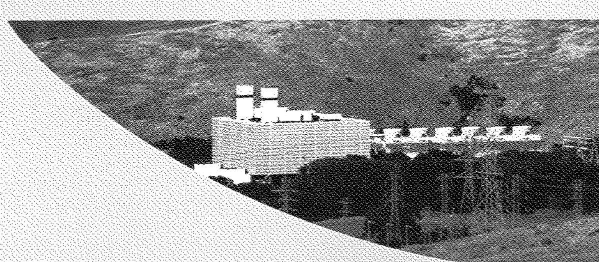
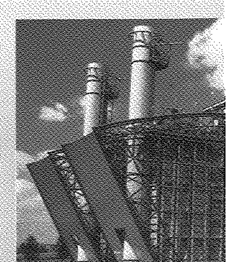
Generating a sustainable future for America











Generating a sustainable future for America

Sustainability is a new way of thinking about an age-old concern: ensuring that our children and grandchildren inherit a tomorrow that is at least as good as today, preferably better. Economic prosperity, environmental progress and community concerns are the key aspects of sustainability. Electricity impacts the intersection of all three. It must be reliable, clean and affordable to help create a sustainable future.

For years, Calpine has invested its capital in technologically advanced natural gas-fired power plants, including highly efficient cogeneration plants, as well as baseload geothermal power plants.

– We believe that clean burning natural gas-fired generation is critical to America's effort to create a sustainable future. In the power business, the top priority – for regulators, systems operators and generators – is to provide customers with reliable, affordable power. Flexibility is a critical component of meeting this goal. First, power demand can vary significantly throughout any given hour, day, week or month, and it's important that there be enough capacity available to quickly come online to respond to peaks in demand. Second, most renewable energy sources are unreliable, particularly when the sun doesn't shine and the wind doesn't blow. These technologies need the backstop of a more reliable form of generation that is provided by natural gas-fired power plants. For these reasons, Calpine's flexible fleet of natural gas-fired power plants plays a critical role in generating the reliable power that is needed to run America's businesses and homes. Our plants can respond quickly and reliably to address variable demand and respond when less reliable sources of energy go offline.

– Cogeneration, the process of converting fuel (in our case natural gas) into steam as well as electricity for use at industrial facilities, can more than double fuel efficiency, resulting in significantly fewer greenhouse gas emissions compared to conventional methods.

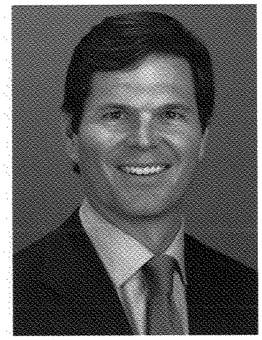
– Geothermal generation is the most reliable form of baseload, renewable power production of scale. The availability and generating capabilities of geothermal plants don't depend on the daily weather, so they can be counted upon to provide power around the clock.

Calpine is the largest pure-play independent power producer in the country measured by electricity produced, with enough capacity to power 24 million homes with our 76 operating power plants located across 16 states. We are also the largest U.S. independent operator of cogeneration plants and our fleet of geothermal plants is the largest in the nation.

Calpine is doing its part to help create a sustainable future by producing reliable, clean and affordable power for America. Importantly, Calpine and its shareholders are well-positioned to benefit from the existing and impending changes in national climate change policy.

v Calpine Headquarters, Houston, Texas

Chairman's Message



Dear Fellow Shareholders,

As I write this letter, Calpine, like every company, is facing unprecedented macroeconomic conditions. Nevertheless, I can report to you with the confidence that in 2008 Calpine achieved important progress despite extraordinary challenges – progress that enabled us to build a solid foundation for managing through these turbulent times and creating long-term value.

Given the demands of the current economic climate, including the dislocations in the financial markets, it is significant that we successfully emerged from bankruptcy in January 2008 with a favorably priced and long-dated capital structure, our debt reduced by $7 billion and only 31 percent of our remaining debt maturing before 2014. As a result, we had the financial strength, flexibility, and liquidity we needed to withstand last year's extraordinary volatility in natural gas prices and to manage the company effectively despite the continuing macroeconomic turmoil.

In connection with our emergence, we recruited a highly qualified Board of Directors with a diverse skill set and experience base. Perhaps most important, in late Summer of last year our Board of Directors was able to attract Jack Fusco as President and Chief Executive Officer, putting in place the highly capable leader of the talented management team that is now guiding the company through today's challenging conditions. Jack quickly augmented Calpine's senior management team with some seasoned executives with whom he previously worked, bringing further depth and talent to Calpine's leadership ranks. The Board and management are working together effectively and constructively to set the company's strategy and move forward with singular focus on building value for shareholders by capitalizing on Calpine's strengths.

Indeed, we all believe Calpine has the potential for meaningful growth in value. That conviction was reinforced during 2008 by our thorough review and analysis of an unsolicited merger offer that we ultimately determined undervalued the company.

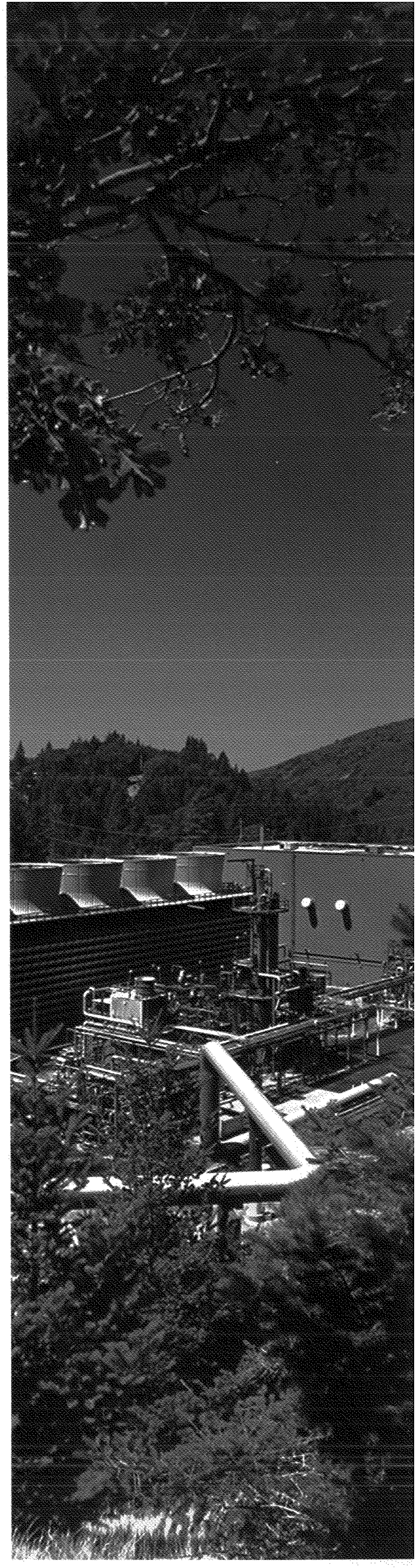
As a fellow shareholder I share your dissatisfaction with Calpine's current share price. Nevertheless, as Jack outlines in his own message to you, there are many reasons why we remain optimistic about Calpine's future. Our management team and Board share a broad perspective on how the markets and demand for power will evolve. With this common view driving decision-making, we have taken important action to position Calpine to benefit as the economy improves and as our country moves toward cleaner and more efficient sources of electricity.

Calpine's strong leadership, decisive actions and the tireless dedication of our employees have enabled the company to meet the unique and substantial challenges of 2008 and early 2009. On behalf of the Board, I would like to extend our thanks to all of the hard-working people of Calpine. In 2009 and beyond, we look to them to continue to exercise the prudent and responsible leadership that is necessary during tumultuous times, while positioning our company for significant long-term value creation.

Sincerely,

William J. Patterson

William J. Patterson
Chairman of the Board



> The Geysers, Calif.
Geothermal facility

Dear Fellow Shareholders,

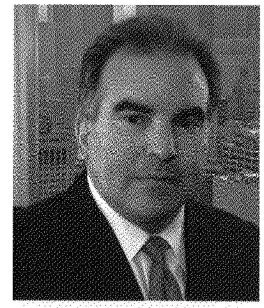
On August 10, 2008, I accepted the Board's offer to take the helm of Calpine Corporation with great anticipation. Calpine presented a unique opportunity in the independent power sector to create meaningful shareholder value through increasing utilization of existing assets. Its modern, clean and efficient portfolio of natural gas-fired power plants as well as the nation's largest geothermal fleet, together producing more power for the U.S. markets than any pure-play independent power company, made it a leader among its peers. I was confident we could achieve significant progress by re-invigorating the talented workforce after years of distractions, re-vamping the operating and corporate organizations to improve effectiveness and lower costs, better commercializing the assets to increase revenues and hedge undue risk, and helping shape the shift in national climate change policy. My fundamental conviction about Calpine's potential led me to make a substantial personal investment in the company only weeks after joining, further aligning my interests with yours as a shareholder.

My challenge has grown more complex, as the duration and intensity of the global financial crisis and the resulting economic turbulence have exceeded expectations, and along with you I feel the pain of our share price decline. Yet, despite the setbacks presented by this turmoil, I remain convinced that Calpine is uniquely well-positioned to create meaningful shareholder value as the economy recovers, while helping to generate a sustainable future for America. More specifically, as the electric markets recover, Calpine should benefit from both price and volume expansion, as we continue to increase the output from our power plants and prices rebound.

Calpine is in sound financial condition and your management team has a well-defined strategic business plan. We have actively worked to preserve existing value while taking steps, where appropriate, to position Calpine to opportunistically benefit from an economic upturn and climate change initiatives. In this letter I will outline our accomplishments in 2008 and address our initiatives for 2009 and beyond. But first, a few words on how we have protected your investment this year and next.

Soon after joining Calpine it became apparent that, given the projected economic downturn, it would be prudent to substantially hedge commodity margins for two reasons: first, to mitigate or eliminate default risk under the financial performance covenants in our debt instruments under any reasonable natural gas price scenario; and second, to mitigate the risk that our earnings would decrease substantially in a severe economic downturn, due to lower natural gas prices in our key power markets where natural gas-fired generation is on the margin and sets the market price for power.

For these reasons, we hedged our commodity margin for the balance of 2008, which permitted us to achieve our reported financial performance despite the disruption to the economy in the last quarter. During the third and fourth quarters of 2008, we also substantially hedged 2009 commodity margin so that, assuming we are able to manage costs to budget in 2009, we expect to be able to achieve financial performance substantially level year over year as indicated by our 2009 guidance. Similarly, as the potential depth and duration of the general economic downturn became more evident, we deemed it equally prudent to hedge 2010 commodity margin, although for 2010 we hedged in a manner that, while establishing a floor, also sought to preserve a modest upside potential should the economy recover and natural gas prices climb. Due to the lack of visibility of economic conditions and natural gas prices in 2011, we also deemed it prudent to hedge a portion of our 2011 commodity price exposure, but only to the extent necessary to mitigate financial covenant risk under any reasonable natural gas price scenario, leaving our 2011 business in a better position to benefit from a recovery. We, of course, will closely monitor economic conditions and commodity prices and, if appropriate, take more risk off the table for 2011. For now, however, we are positioned so that should the economy and commodity prices improve, Calpine will be able to capture upside. In summary, we believe that by minimizing financial covenant risk under any reasonable natural gas price scenario in 2009-2010 and mitigating it in 2011, while also preserving our margins in 2009 and upside in 2010, we have taken meaningful measures to protect shareholder interests during this period of economic uncertainty.



It also became apparent to me shortly after joining Calpine that assuring substantial and quality liquidity would be important to weathering the economic downturn and the contraction of the capital markets. Our liquidity was about $2.2 billion at 2008 year end, including $725 million which we elected to draw under our revolving credit facility, rather than continue to take lender default risk. This, along with our projected free cash flow, should enable us to meet our current obligations including debt service and collateral demands, as well as to repay debt coming due in the second half of this year and the first half of next if we are not able to refinance the debt in the capital markets on terms that are acceptable to us.

These measures, which I believe have given Calpine a sound and manageable capital structure, strong liquidity and margins generally stabilized over the next two years, will, together with our 2008 accomplishments and enhanced by our 2009 initiatives, described below, provide Calpine with a strong platform for the medium- to long-term horizon.

Our Accomplishments in 2008

ORGANIZATION

- We successfully emerged from bankruptcy.
- We eliminated the use of costly consultants and replaced them with highly-qualified professionals familiar with the industry and with a vested interest in Calpine.
- We initiated a restructuring of our operations and corporate groups, established new operating performance metrics, and set a strong tone-at-the-top style management. These steps are important in helping transform Calpine into a best-in-class *operating* company with the focus where it belongs: producing power for our customers.
- We created a vision, mission and values statement, set forth on page 6 of this Annual Report, to assist employees in focusing on creating value for Calpine. Our vision is to become the premier independent power company in the United States.

Power Operations

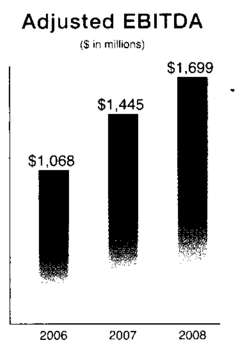
- As a former power plant worker, I was especially proud of our 2008 safety performance. We achieved a lost-time incident rate of 0.17, placing us in the top-quartile of our industry.
- Our power operations team generated 89 million megawatt hours of electricity for customers in 16 states and Canada, a quantity we believe continues to place us at the top of league tables for power production in our sector.
- As owner of the largest fleet of highly energy efficient cogeneration plants, we produced 52.5 billion pounds of steam for our industrial customers at 24 locations.
- Our 2008 fleet-wide steam-adjusted heat rate of 7,231 btu/KWh demonstrated that we were able to produce that power at a highly efficient rate, thereby using less natural resources per unit of power produced.
- We commenced commercial operations at the jointly owned Greenfield Energy Centre in Ontario, Canada during the fourth quarter.

Commercial Operations

- Our commercial team effectively managed immediate challenges such as Hurricanes Gustav and Ike.
- This team also carried out exceptional execution of the hedging strategies previously discussed.
- We were able to increase the use of our first lien collateral program by about 260 percent since the Fall of 2008, freeing cash collateral for other uses and eliminating the risk of future cash collateral calls by those counterparties in the program in the event of commodity price increases.
- We entered into a 10-year power purchase agreement with Pacific Gas & Electric which, if approved by regulators, will allow us to develop the 600 MW Russell City Energy Center in California, pending approval of certain air permits.

Financial Performance

- Revenues increased 25 percent over 2007 to $9.9 billion.
- Adjusted EBITDA improved by 18 percent to $1.7 billion.[1]
- We secured attractively-priced corporate debt upon our emergence from bankruptcy. Given the uncertainty in today's credit markets, this financing is beneficial in two regards: it offers us rates that are well below today's market pricing for debt and it should allow us, if necessary, to avoid accessing the capital markets until 2014.
- We opportunistically refinanced project debt at our Blue Spruce, Metcalf and Deer Park plants. As a result of these transactions, we were able to achieve better pricing, remove complicated financing structures and release trapped cash. Notably, the Deer Park refinancing was accomplished on very favorable terms in January 2009 despite difficult market conditions.



As much as we accomplished in 2008, we have even more to do in 2009 toward achieving our vision of becoming the premier independent power company.

At an organizational level, we will tackle the implementation of substantial new enterprise, risk management and other systems and processes designed, among other things, to increase our accounting effectiveness and the quality and availability of management and financial reporting data while reducing our overall costs. This effort will further enhance our ability to make well-informed and timely decisions about our business.

Our commercial team will redouble our origination and marketing efforts to build our relationships with customers in order to secure long-term contracts for our products. Commercial Operations is continuing to develop and execute risk management strategies that protect and enhance value.

In operations, we are targeting major maintenance overhauls on 11 of our power plants. Our efforts to streamline plant operations and related commercial operations, to improve plant reliability and to reorganize the procurement function should gain full speed, and we expect to see real benefits from these initiatives during the year. Our team also will focus on achieving commercial operations this Fall at our Otay Mesa plant in California.

On the financial front, our top priority in 2009 is to continue the effort to optimize our capital structure. We will focus on Adjusted Free Cash Flow as an appropriate measure of our performance.

On a final note, we remain committed to participating in the national dialogue on climate change. We are supportive of measures to reduce greenhouse gas emissions through cap-and-trade programs with the appropriate safeguards for our long-term cogeneration contracts. Calpine and its shareholders should benefit from such regulation, a fair result when one considers that Calpine, with great foresight, has long invested substantial capital in building a clean and highly efficient fleet.

In conclusion, we have taken the actions necessary to assure Calpine is in good shape not only to weather the current tumultuous and volatile market conditions, but to benefit from longer-term recovery and regulatory change. Your Board, management team and all the highly capable employees of Calpine are united in their commitment to building and delivering value for shareholders as we create the premier independent power company in the United States.

Thank you for your continued support.

Jack Fusco

Jack A. Fusco
President and Chief Executive Officer

(1) Adjusted EBITDA, a non-GAAP financial measure, is discussed in our Annual Report on Form 10-K for the year ended December 31, 2008, under "Management's Discussion and Analysis of Financial Condition and Results of Operations," which includes a reconciliation to Net Income, the most comparable GAAP measure. A complete copy of the Form 10-K is included in this Annual Report to Shareholders.

Modern
clean and efficient fleet producing reliable and affordable energy

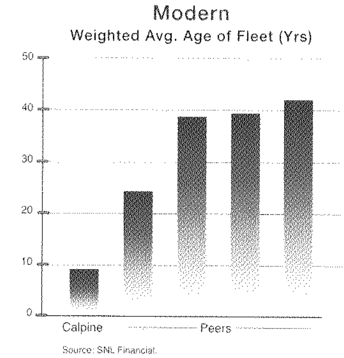
Modern. Calpine is proud to operate the most modern fleet among large scale, U.S. pure independent power producers, with an average power plant age of less than 10 years.

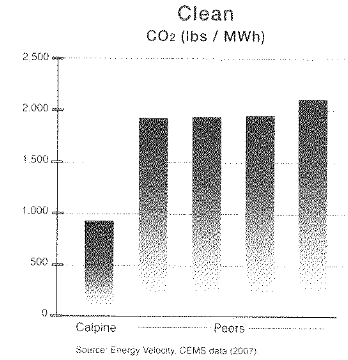
Clean. Our geothermal plants use a renewable resource – geothermal steam. Our natural gas-fired technologies are the cleanest used in fossil fuel power production, emitting relatively low amounts of greenhouse gases and other pollutants. In addition, none of our plants use "once-through" water cooling as do coal and many older technology natural gas-fired plants, minimizing our impact on marine life.

Efficient. Our modern, state-of-the-art natural gas-fired plant technologies, enable us to be highly efficient at producing power. Additionally, our 24 cogeneration plants, which along with power, produce steam for our industrial customers, capture even greater efficiencies. Our fleet-wide steam-adjusted heat rate in 2008 was 7,231 btu/ KWh, which translates to a power conversion efficiency of approximately 47%, considerably exceeding that of older technology natural gas-fired plants and coal-fired plants, which typically range from 31% to 36%.

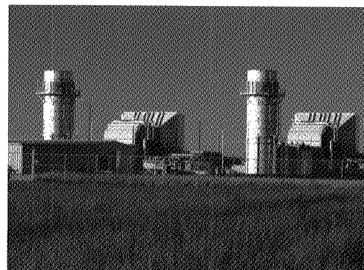
Reliable. Our cogeneration and geothermal plants produce power around the clock while our intermediate plants typically produce power during periods of peak demand and our peaker plants, which can be started on very short notice, produce power during periods of highest demand such as on hot summer days.

Affordable. The high efficiency of our fleet enables us to produce more affordable energy.

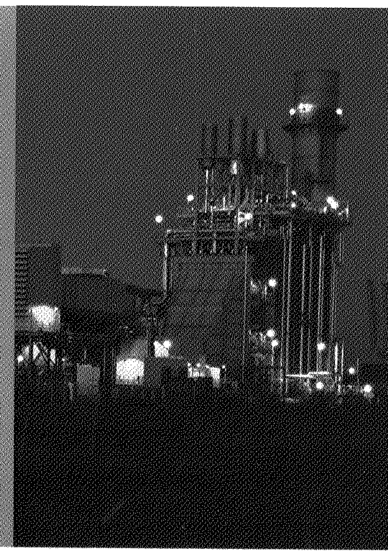




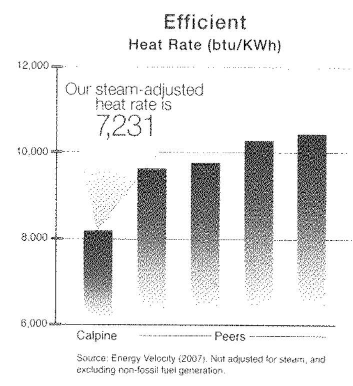
RockGen Energy Center, Wis.
Peaking facility

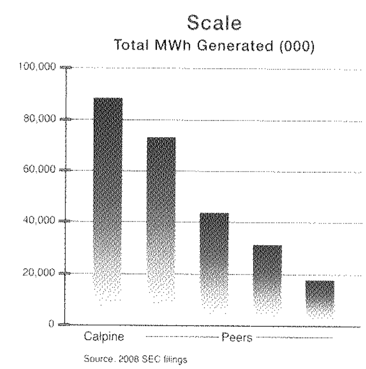


Los Medanos, Calif.
Combined-cycle cogeneration facility



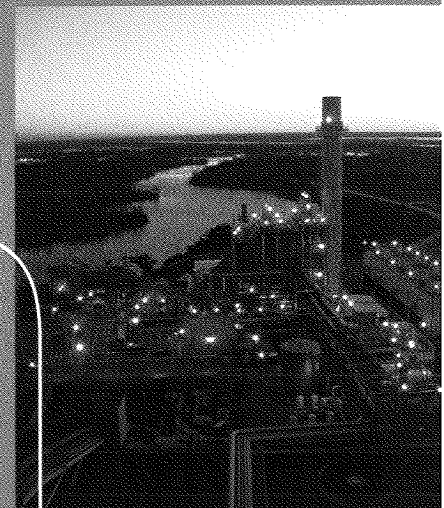
Greenfield Energy Centre, Ontario, Canada
Combined-cycle facility



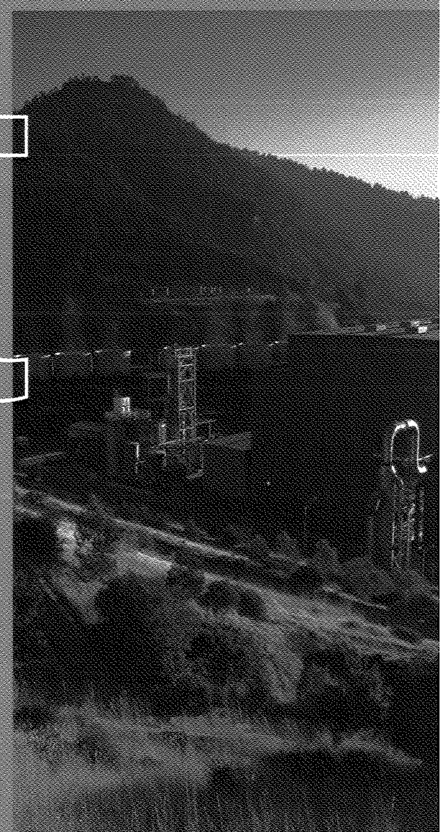


clean fleet

˅ Hog Bayou Energy Center, Ala.
Combined-cycle facility



˄ Magic Valley Generating Station, Texas
Combined-cycle facility



˄ The Geysers, Calif.
Geothermal facility

In early 2009, we were recognized by the Environmental Protection Agency's Combined Heat and Power Partnership for our contributions to efficient domestic energy production and reduced carbon dioxide emissions. Overall, we believe we are well-positioned to address and benefit from many of the federal and state environmental regulations that are expected to affect our industry in the near future.

Our people our values

Our new management has articulated a vision, mission and set of values to which we all ASPIRE:

Our Vision

Our vision is to be the premier independent power company in the United States.

Our Mission

Our mission is to provide clean, reliable and efficient energy and energy-related products to our customers while earning meaningful returns for our shareholders. In pursuit of our mission, we are committed to best-in-class safety and operational excellence; growth through financially disciplined new construction, upgrades to existing facilities and opportunistic acquisitions; meaningful support of our local communities; and environmental stewardship.

Our Values

We ASPIRE to effectively perform every task, every action, every pursuit, and every decision with these values in mind:

Accountability. We embrace our individual responsibility and perform to the best of our ability. We make sure we understand what is expected for the task at hand and execute on it. We always follow the applicable laws, regulations, policies and procedures.

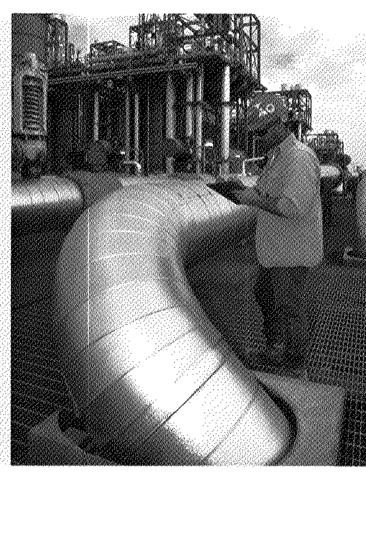
Safety. We put safety first in everything we do. We realize our well-being and that of our colleagues is the responsibility of each one of us and is critical to Calpine's success. We investigate, communicate and proactively manage any unsafe conditions.

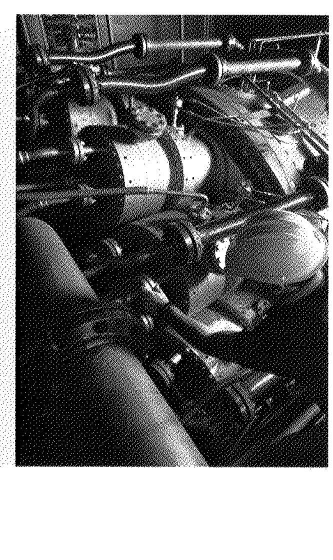
Passion. We work with passion for our business, passion for our community and passion for the environment. Passion to us means a sense of urgency and focus.

Integrity. In all that we do, we demonstrate our integrity by being true to our word. We follow through on commitments to our customers, colleagues, suppliers, investors and communities.

Respect. We cultivate a respectful, nurturing and diverse work environment characterized by open, honest and direct communications. We honor receiving and discussing other points of view, always without fear of reprimand.

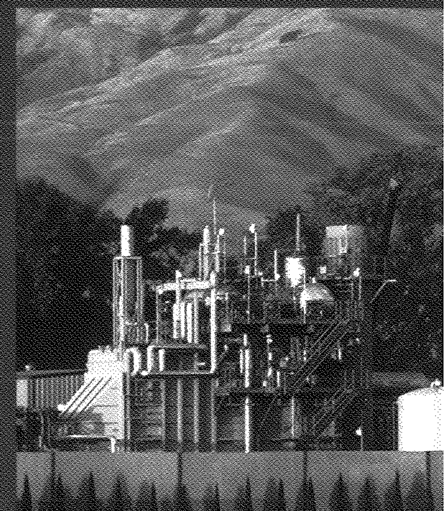
Esprit de Corps. We work with a collective sense of pride and honor in everything that we do. We work as a team where we share, support and encourage each other to achieve our common goals. We encourage, support and mentor our colleagues to help them attain personal achievement.





we aspire

Agnews Power Plant, Calif.
Combined-cycle cogeneration facility



Sutter Energy Center, Calif.
Combined-cycle facility

In 2008, our Magic Valley Generating Station became yet another of our plants to receive the Voluntary Protection Programs (VPP) Star Award from the U.S. Occupational Safety and Health Administration. This prestigious recognition is given to industry leaders with a strong commitment to occupational safety and health that goes above and beyond government standards.

Following our fourth consecutive year of top quartile safety performance, in early 2009 Calpine launched a company-wide "Safety First" campaign to continue our focus on safety.

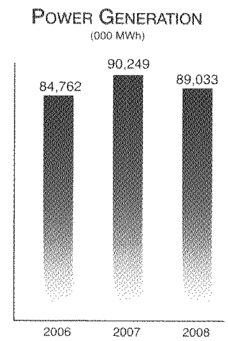
Operational highlights

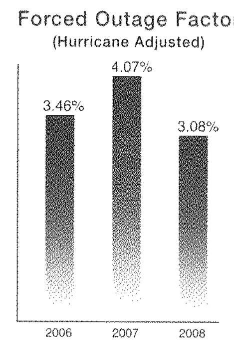
We continue to build upon our reputation for operational excellence.

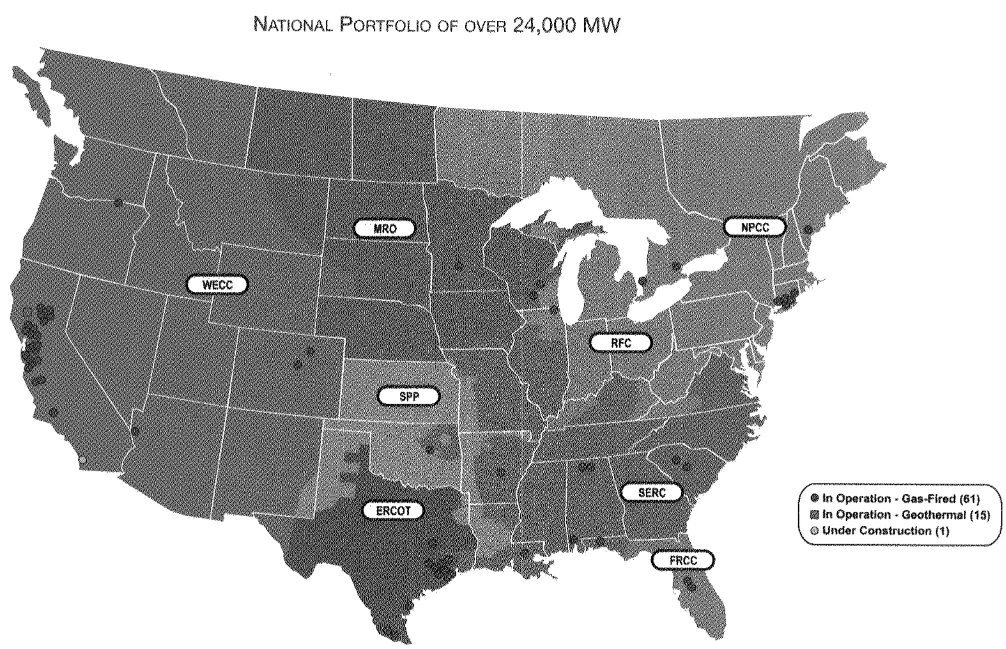
– In 2008, we delivered over 89 million megawatt hours of power to our customers across the country – more than any other pure-play independent producer.

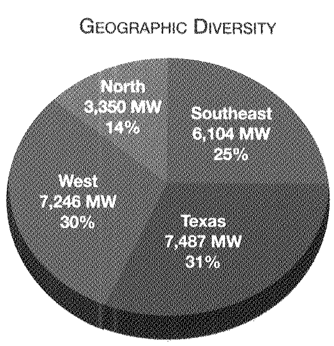
– As the largest operator of cogeneration facilities in the nation, we generated 52.5 billion pounds of steam for the benefit of our industrial customers.

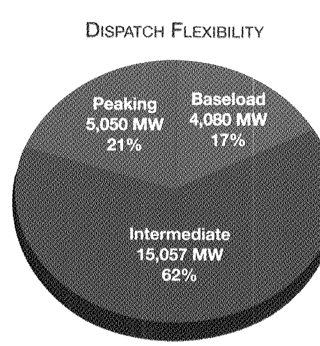
– We reduced our hurricane-adjusted Forced Outage Factor to 3.08%, our lowest rate in four years and a 25% improvement from 2007.

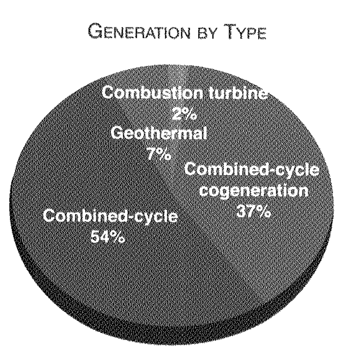












UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

(Mark One)

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

For the fiscal year ended December 31, 2008

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

717 Texas Avenue, Suite 1000, Houston, Texas 77002
50 West San Fernando Street, San Jose, California 95113
Telephone: (713) 830-8775

Securities registered pursuant to Section 12(b) of the Act:
Calpine Corporation Common Stock, $.001 Par Value

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

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes [X] No [ ]

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes [ ] No [X]

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

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

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

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

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

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: Calpine Corporation: 428,749,395 shares of common stock, par value $.001, were outstanding as of February 25, 2009.

State the aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2008, the last business day of the registrant's most recently completed second fiscal quarter: approximately $4,437 million.

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

DOCUMENTS INCORPORATED BY REFERENCE

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

Designated portions of the Proxy Statement relating to the 2009 Annual Meeting of Shareholders are incorporated by reference into Part III (Items 10, 11, 12, 13 and 14)

CALPINE CORPORATION AND SUBSIDIARIES

FORM 10-K

ANNUAL REPORT
For the Year Ended December 31, 2008

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DEFINITIONS

As used in this Report, the following abbreviations and terms have the meanings as listed below. Additionally, the terms "Calpine," "we," "us" and "our" refer to Calpine Corporation and its consolidated subsidiaries, unless the context clearly indicates otherwise. For clarification, for the period from December 20, 2005, through February 7, 2008, such terms do not include the Canadian Debtors and other foreign subsidiaries that were deconsolidated as of the Petition Date. The term "Calpine Corporation" refers only to Calpine Corporation and not to any of its subsidiaries. Unless and as otherwise stated, any references in this Report to any agreement means such agreement and all schedules, exhibits and attachments in each case as amended, restated, supplemented or otherwise modified to the date of filing this Report.

ABBREVIATION	DEFINITION
2014 Convertible Notes	Calpine Corporation's Contingent Convertible Notes Due 2014
401(k) Plan	Calpine Corporation Retirement Savings Plan
Acadia PP	Acadia Power Partners, LLC
Adjusted EBITDA	EBITDA adjusted to remove the income effects of (a) non-cash losses on sales, dispositions or impairments of assets, (b) any unrealized gains or losses and any non-cash realized gains or losses from accounting for derivatives, (c) non cash stock compensation expense, (d) operating lease expense, (e) non-cash gains and losses from intercompany foreign currency translations, (f) reorganization items, (g) major maintenance expense, (h) any non-cash gain or loss on the repurchase or extinguishment of debt and (i) any other extraordinary, unusual or non-recurring income plus our net interest in the Adjusted EBITDA of our unconsolidated investments
AOCI	Accumulated Other Comprehensive Income
APH	Acadia Power Holdings, LLC, a wholly owned subsidiary of Cleco
ARB	Accounting Research Board
Aries Power Plant	MEP Pleasant Hill, LLC
ASC	Aircraft Services Corporation, an affiliate of General Electric Capital Corporation
Auburndale	Auburndale Holdings, LLC
Average availability	Availability represents the percent of total hours during the period that our plants were available to run after taking into account the downtime associated with both scheduled and unscheduled outages.
Average capacity factor (excluding peakers)	The average capacity factor (excluding peakers) is a measure of total actual generation as a percent of total potential generation. It is calculated by dividing (a) total MWh generated by our power plants (excluding peakers) by (b) the product of multiplying (i) the weighted average capacity during the period by (ii) the total hours in the period. The weighted average capacity reflects the seasonally adjusted capacity of our plants (except our mothballed plants) during the period, including any time the plants may not be operating due to scheduled and unscheduled outages for maintenance and repair requirements or because we elect not to generate when power prices are too low or natural gas prices are too high to operate profitably
Bankruptcy Code	U.S. Bankruptcy Code
Bankruptcy Courts	The U.S. Bankruptcy Court and the Canadian Court
Bcf	Billion cubic feet
BLM	Bureau of Land Management of the U.S. Department of the Interior

ABBREVIATION	DEFINITION
Blue Spruce	Blue Spruce Energy Center LLC
Bridge Facility	Bridge Loan Agreement, dated as of January 31, 2008, among Calpine Corporation as borrower, the lenders party thereto, Goldman Sachs Credit Partners L.P., Credit Suisse, Deutsche Bank Securities Inc. and Morgan Stanley Senior Funding Inc., as co-documentation agents, and Goldman Sachs Credit Partners L.P., as administrative agent and collateral agent
Btu	British thermal unit(s), a measure of heat content
CAA	Federal Clean Air Act, United States Code Title 42, Chapter 85
CAIR	Clean Air Interstate Rule (Rule to Reduce Interstate Transport of Fine Particulate Matter and Ozone, 40 CFR Parts 51 and 96)
CAISO	California Independent System Operator
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 Corp.; $600,000,000 First Priority Secured Institutional Term Loans Due 2009 issued by CalGen; and the CalGen First Priority Revolving Loans, in each case repaid on March 29, 2007
CalGen First Priority Revolving Loans	$200,000,000 First Priority Revolving Loans issued on or about March 23, 2004, pursuant to that Amended and Restated Agreement, among CalGen, the guarantors party thereto, the lenders party thereto, The Bank of Nova Scotia, as administrative agent, L/C Bank, lead arranger and sole bookrunner, Bayerische Landesbank, Cayman Islands Branch, as arranger and co-syndication agent, Credit Lyonnais, New York Branch, as arranger and co-syndication agent, ING Capital LLC, as arranger and co-syndication agent, Toronto Dominion (Texas) Inc., as arranger and co-syndication agent, and Union Bank of California, N.A., as arranger and co-syndication agent, repaid on March 29, 2007
CalGen Second Lien Debt	Collectively, $640,000,000 Second Priority Secured Floating Rate Notes Due 2010 issued by CalGen and CalGen Finance Corp.; and $100,000,000 Second Priority Secured Institutional Term Loans Due 2010 issued by CalGen, in each case repaid on March 29, 2007
CalGen Secured Debt	Collectively, the CalGen First Lien Debt, the CalGen Second Lien Debt and the CalGen Third Lien Debt
CalGen Third Lien Debt	Collectively, $680,000,000 Third Priority Secured Floating Rate Notes Due 2011 issued by CalGen and CalGen Finance Corp.; and $150,000,000 11 1/2% Third Priority Secured Notes Due 2011 issued by CalGen and CalGen Finance Corp., in each case repaid on March 29, 2007
Calpine Debtors	The U.S. Debtors and the Canadian Debtors
Calpine Equity Incentive Plans	Collectively, the MEIP and the DEIP, which provide for grants of equity awards to Calpine employees and non-employee members of Calpine's Board of Directors
Canadian Court	The Court of Queen's Bench of Alberta, Judicial District of Calgary
Canadian Debtors	The subsidiaries and affiliates of Calpine Corporation that have been granted creditor protection under the CCAA in the Canadian Court
Canadian Effective Date	February 8, 2008, the date on which the Canadian Court ordered and declared that the Canadian Debtors' proceedings under the CCAA were terminated

ABBREVIATION	DEFINITION
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
Cap-and-trade	A government imposed GHG emissions reduction program that would place a cap on the amount of GHG emissions that can be emitted from certain sources, such as power plants. In its most common form, the cap amount is set as a reduction from the total emissions during a base year and for each year over a period of years the cap amount would be reduced to achieve the targeted overall reduction by the end of the period. Allowances or credits for emissions in an amount equal to the cap would be issued or auctioned to companies with facilities, permitting them to emit up to a certain amount of GHG during each applicable period. After allowances have been distributed or auctioned, they can be transferred, or traded
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
CERCLA	Comprehensive Environmental Response, Compensation and Liability Act, U.S. Code Title 42, Chapter 103, as amended, also called "Superfund"
CES	Calpine Energy Services, L.P.
CFR	Code of Federal Regulations
CFTC	Commodities Futures Trading Commission
Chapter 11	Chapter 11 of the Bankruptcy Code
Cleco	Cleco Corp.
CO_2	Carbon dioxide
COD	Commercial operations date
Cogeneration	Using a portion or all of the steam generated in the combined-cycle power generating process to supply a customer with steam for use in the customer's operations

ABBREVIATION	DEFINITION
Commodity Collateral Revolver	Commodity Collateral Revolving Credit Agreement, dated as of July 8, 2008, among Calpine Corporation as borrower, Goldman Sachs Credit Partners L.P., as payment agent, sole lead arranger and sole bookrunner, and the lenders from time to time party thereto
Commodity expense	The sum of our GAAP expenses from fuel expense, purchased power and natural gas expense including for hedging and optimization, and fuel transportation expense but excluding mark-to-market activity
Commodity Margin	Non-GAAP financial measure that includes power and steam revenues, marketing, hedging and optimization activities, REC revenue, transmission revenue and expenses, and fuel and purchased power expense, but excludes mark-to-market activity and other revenues
Commodity revenue	The sum of our GAAP revenues from power and steam sales and sales of purchased power and natural gas
Company	Calpine Corporation, a Delaware corporation, and subsidiaries
Confirmation Order	The order of the U.S. Bankruptcy Court entitled "Findings of Fact, Conclusions of Law, and Order Confirming Sixth Amended Joint Plan of Reorganization Pursuant to Chapter 11 of the Bankruptcy Code," entered December 19, 2007, confirming the Plan of Reorganization pursuant to section 1129 of the Bankruptcy Code
Convertible Senior Notes	Collectively, Calpine Corporation's 4% Contingent Convertible Notes Due 2006, 6% Contingent Convertible Notes Due 2014, 7 3/4% Contingent Convertible Notes Due 2015 and 4 3/4% Contingent Convertible Senior Notes Due 2023
CPIF	Calpine Power Income Fund
CPUC	California Public Utilities Commission
Creditors' Committee	The Official Committee of Unsecured Creditors of Calpine Corporation appointed by the Office of the U.S. Trustee
Creed	Creed Energy Center, LLC
DB London	Deutsche Bank AG London
Deer Park	Deer Park Energy Center Limited Partnership
DEIP	Calpine Corporation 2008 Director Incentive Plan, which provides for grants of equity awards to non-employee members of Calpine's Board of Directors
DIP	Debtor-in-possession
DIP Facility	The Revolving Credit, Term Loan and Guarantee Agreement, dated as of March 29, 2007, among Calpine Corporation, as borrower, certain of Calpine Corporation'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

ABBREVIATION	DEFINITION
Disclosure Statement	Disclosure Statement for the U.S. Debtors' Joint Plan of Reorganization Pursuant to Chapter 11 of the Bankruptcy Code filed by the U.S. Debtors with the U.S. Bankruptcy Court on June 20, 2007, as amended, modified or supplemented through the filing of this Report pursuant to the Plan of Reorganization
EBITDA	Earnings before interest, taxes, depreciation, and amortization
ECM(s)	Exempt Commercial Market(s)
Effective Date	January 31, 2008, the date on which the conditions precedent enumerated in the Plan of Reorganization were satisfied or waived and the Plan of Reorganization became effective
EIA	Energy Information Administration of the U.S. Department of Energy
EITF	Emerging Issues Task Force
Emergence Date Market Capitalization	Determined as Calpine's Market Capitalization using the 30-day weighted average stock price following the Effective Date
EPA	U.S. Environmental Protection Agency
EPAct 1992	Energy Policy Act of 1992
EPAct 2005	Energy Policy Act of 2005
EPS	Earnings per share
ERCs	Emission reduction credits
ERCOT	Electric Reliability Council of Texas
ERISA	Employee Retirement Income Security Act
ERO	Electric Reliability Organization
EWG(s)	Exempt wholesale generator(s)
Exchange Act	U.S. Securities Exchange Act of 1934, as amended
Exit Credit Facility	Credit Agreement, dated as of January 31, 2008, among Calpine Corporation, as borrower, the lenders party thereto, General Electric Capital Corporation, as sub-agent, Goldman Sachs Credit Partners L.P., Credit Suisse, Deutsche Bank Securities Inc., and Morgan Stanley Senior Funding, Inc., as co-syndication agents and co-documentation agents, and Goldman Sachs Credit Partners L.P., as administrative agent and collateral agent
Exit Facilities	Together, the Exit Credit Facility and the Bridge Facility
FASB	Financial Accounting Standards Board
FDIC	Federal Deposit Insurance Corporation
FERC	Federal Energy Regulatory Commission
FIN	FASB Interpretation
First Priority Notes	9 5/8% First Priority Senior Secured Notes Due 2014
FPA	Federal Power Act
FRCC	Florida Reliability Coordinating Council
Fremont	Fremont Energy Center, LLC
FSP	FASB Staff Position
FUCO(s)	Foreign Utility Company(ies)
GAAP	Generally accepted accounting principles
GE	General Electric International, Inc.

ABBREVIATION	DEFINITION
GEC	Collectively, Gilroy Energy Center, LLC, Creed Energy Center, LLC and Goose Haven Energy Center, LLC
Geysers Assets	17 (15 operating power plants with 17 turbines and two plants not in operation) geothermal power plant assets located in northern California
GHG(s)	Greenhouse gas(es), primarily CO_2, and including methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs)
Gilroy	Calpine Gilroy Cogen, L.P.
Goose Haven	Goose Haven Energy Center, LLC
Greenfield LP	Greenfield Energy Centre LP
Heat Rate(s)	A measure of the amount of fuel required to produce a unit of power
Hg	Mercury
Hillabee	Hillabee Energy Center, LLC
ICT	Independent Coordinator of Transmission
IESO	Independent Electricity System Operator of Ontario
IPPs	Independent power producers
IRC	Internal Revenue Code
IRS	U.S. Internal Revenue Service
ISO(s)	Independent System Operator(s)
ISO NE	ISO New England
King City Cogen	Calpine King City Cogen, LLC
Knock-in Facility	Letter of Credit Facility Agreement, dated as of June 25, 2008, among Calpine Corporation as borrower and Morgan Stanley Capital Services Inc., as issuing bank
KWh	Kilowatt hour(s), a measure of power produced
LIBOR	London Inter-Bank Offered Rate
LNG	Liquified natural gas
LSTC	Liabilities subject to compromise
LTSA(s)	Long-Term Service Agreement(s)
Market Capitalization	Market value of Calpine Corporation common stock outstanding, calculated in accordance with the Calpine Corporation amended and restated certificate of incorporation
Market Heat Rate(s)	The regional power price divided by the corresponding regional natural gas price
MEIP	Calpine Corporation 2008 Equity Incentive Plan, which provides for grants of equity awards to Calpine employees
Metcalf	Metcalf Energy Center, LLC
MISO	Midwest ISO
MMBtu	Million Btu
MRO	Midwest Reliability Organization
MRTU	CAISO's Market Redesign and Technology Upgrade
MW	Megawatt(s), a measure of plant performance

ABBREVIATION	DEFINITION
MWh	Megawatt hour(s), a measure of power produced
NAAQS	National Ambient Air Quality Standards
NERC	North American Electric Reliability Council
NGA	Natural Gas Act
NGPA	Natural Gas Policy Act
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. Debtors
Northern District Court	U.S. District Court for the Northern District of California
NOx	Nitrogen oxide
NPCC	Northeast Power Coordinating Council
NRG	NRG Energy, Inc.
NYISO	New York Independent System Operator
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
O&M	Operations and maintenance
OCI	Other Comprehensive Income
OMEC	Otay Mesa Energy Center, LLC
Original DIP Facility	The Revolving Credit, Term Loan and Guarantee Agreement, dated as of December 22, 2005, as amended on January 26, 2006, and as amended and restated by that certain Amended and Restated Revolving Credit, Term Loan and Guarantee Agreement, dated as of February 23, 2006, among Calpine Corporation, as borrower, the Guarantors party thereto, the Lenders from time to time party thereto, Credit Suisse Securities (USA) LLC and Deutsche Bank Securities Inc., as joint syndication agents, Deutsche Bank Trust Company Americas, as administrative agent for the First Priority Lenders, General Electric Capital Corporation, as Sub-Agent for the Revolving Lenders, Credit Suisse, as administrative agent for the Second Priority Term Lenders, Landesbank Hessen Thuringen Girozentrale, New York Branch, General Electric Capital Corporation and HSH Nordbank AG, New York Branch, as joint documentation agents for the First Priority Lenders and Bayerische Landesbank, General Electric Capital Corporation and Union Bank of California, N.A., as joint documentation agents for the Second Priority Lenders
OTC	Over-the-Counter
Panda	Panda Energy International, Inc., and related party PLC II, LLC
PCF	Power Contract Financing, L.L.C.
PCF III	Power Contract Financing III, LLC

ABBREVIATION	DEFINITION
Petition Date	December 20, 2005
PG&E	Pacific Gas & Electric Company
Pink Sheets	Pink Sheets Electronic Quotation Service maintained by Pink Sheets LLC for the National Quotation Bureau, Inc.
PJM	Pennsylvania-New Jersey-Maryland Interconnection
Plan of Reorganization	Debtors' Sixth Amended Joint Plan of Reorganization Pursuant to Chapter 11 of the Bankruptcy Code filed by the U.S. Debtors with the U.S. Bankruptcy Court on December 19, 2007, as amended, modified or supplemented through the filing of this Report
Pomifer	Pomifer Power Funding, LLC, a subsidiary of Arclight Energy Partners Fund I, L.P.
PPA(s)	Any term power purchase agreement or other contract for a physically settled sale (as distinguished from a financially settled future, option or other derivative or hedge transaction) of any electric power product, including electric energy, capacity and/or ancillary services, in the form of a bilateral agreement or a written or oral confirmation of a transaction between two parties to a master agreement, including sales related to a tolling transaction in which part of the consideration provided by the purchaser of an electric power product is the fuel required by the seller to generate such electric power
PSM	Power Systems Manufacturing, LLC
PUC(s)	Public Utility Commission(s)
PUCT	Public Utility Commission of Texas
PUHCA 1935	Public Utility Holding Company Act of 1935
PUHCA 2005	Public Utility Holding Company Act of 2005
PURPA	Public Utility Regulatory Policies Act of 1978
QF(s)	Qualifying facility(ies), which are Cogeneration facilities and certain small power production facilities eligible to be "qualifying facilities" under PURPA, provided that they meet certain power and thermal energy production requirements and efficiency standards. QF status provides an exemption from PUHCA 2005 and grants certain other benefits to the QF
RCRA	Resource Conservation and Recovery Act, U.S. Code Title 42, Chapter 82
REC(s)	Renewable Energy Credit(s)
Reserve margin(s)	The measure of how much the total generating capacity installed in a region exceeds the peak demand for power in that region
RFC	Reliability *First* Corporation
RGGI	Regional Greenhouse Gas Initiative
RMR Contract(s)	Reliability Must Run contract(s)
RockGen	RockGen Energy LLC
RockGen Owner Lessors	Collectively, RockGen OL-1, LLC; RockGen OL-2, LLC; RockGen OL-3, LLC and RockGen OL-4, LLC
Rosetta	Rosetta Resources Inc.
RPS	Renewable Portfolio Standards
RTO(s)	Regional Transmission Organization(s)

ABBREVIATION	DEFINITION
SAB	SEC Staff Accounting Bulletin
SDG&E	San Diego Gas & Electric Company
SDNY Court	U.S. District Court for the Southern District of New York
SEC	U.S. Securities and Exchange Commission
Second Circuit	U.S. Court of Appeals for the Second Circuit
Second Priority Debt	Collectively, the Second Priority Notes and the Second Priority Senior Secured Term Loans due 2007
Second Priority Notes	Calpine Corporation's Second Priority Senior Secured Floating Rate Notes due 2007, 8 1/2% Second Priority Senior Secured Notes due 2010, 8 3/4% Second Priority Senior Secured Notes due 2013 and 9 7/8% Second Priority Senior Secured Notes due 2011
Securities Act	U.S. Securities Act of 1933, as amended
SERC	Southeastern Electric Reliability Council
SFAS	Statement of Financial Accounting Standards
SO_2	Sulfur dioxide
SOP 90-7	Statement of Position 90-7, "Financial Reporting by Entities in Reorganization Under the Bankruptcy Code"
Spark spread(s)	The difference between the sales price of power per MWh and the cost of fuel to produce it
SPP	Southwest Power Pool
Steam Adjusted Heat Rate	The adjusted Heat Rate for our natural gas-fired power plants, excluding peakers, calculated by dividing (a) the fuel consumed in Btu reduced by the net equivalent Btu in steam exported to a third party by (b) the KWh generated. Steam Adjusted Heat Rate is a measure of fuel efficiency, so the lower our Steam Adjusted Heat Rate, the lower our cost of generation
TCEQ	Texas Commission on Environmental Quality
TMG	Turbine Maintenance Group
TTS	Thomassen Turbine Systems, B.V.
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 Senior Notes	Collectively, Calpine Corporation's 7 5/8% Senior Notes due 2006, 10 1/2% Senior Notes due 2006, 8 3/4% Senior Notes due 2007, 7 7/8% Senior Notes due 2008, 7 3/4% Senior Notes due 2009, 8 5/8% Senior Notes due 2010 and 8 1/2% Senior Notes due 2011
U.S.	United States of America
U.S. Bankruptcy Court	U.S. Bankruptcy Court for the Southern District of New York
U.S. Debtor(s)	Calpine Corporation and each of its subsidiaries and affiliates that filed voluntary petitions for reorganization under Chapter 11 of the Bankruptcy Code in the U.S. Bankruptcy Court on or after the Petition Date and prior to the Effective Date, 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)

ABBREVIATION	DEFINITION
VAR	Value-at-risk
VIE(s)	Variable interest entity(ies)
WCI	Western Climate Initiative
WECC	Western Electricity Coordinating Council
Whitby	Whitby Cogeneration Limited Partnership
WP&L	Wisconsin Power & Light Company

Forward-Looking Statements

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

- The uncertain length and severity of the current general financial and economic downturn and its impacts on our business including demand for our power products, the ability of our counterparties to perform under their contracts with us and the cost and availability of capital and credit;

- The effects of fluctuations in liquidity and volatility in the energy commodities markets including our ability to hedge risks;

- The ability of our customers, suppliers, service providers and other contractual counterparties to perform under their contracts with us;

- Our ability to manage our significant liquidity needs and to comply with covenants under our Exit Credit Facility and other existing financing obligations;

- Financial results that may be volatile and may not reflect historical trends due to, among other things, general economic and market conditions outside of our control, the ability of our counterparties to perform their contracts with us and the effects of our Chapter 11 reorganization;

- Seasonal fluctuations of our results and exposure to variations in weather patterns;

- Fluctuations in prices for commodities such as natural gas and power;

- Our ability to implement our new business plan and strategy;

- Our ability to attract and retain customers and counterparties, including suppliers and service providers, and to manage our customer and counterparty exposure and credit risk, including our commodity positions;

- Competition, including risks associated with marketing and selling power in the evolving energy markets;

- Regulation in the markets in which we participate and our ability to effectively respond to changes in laws and regulations or the interpretation thereof including changing market rules and evolving federal, state and regions laws and regulations including those related to GHG emissions;

- Present and possible future claims, litigation and enforcement actions, including our ability to complete the implementation of our Plan of Reorganization;

- Our ability to attract, retain and motivate key employees;

- Natural disasters such as hurricanes, earthquakes and floods that may impact our power plants or the markets our power plants serve;

- Disruptions in or limitations on the transportation of natural gas and transmission of power;

- Risks associated with the operation, construction and development of power plants including unscheduled outages or delays and plant efficiencies;

- Risks related to our geothermal resources, including the adequacy of our steam reserves, unusual or unexpected steam field well and pipeline maintenance requirements and variables associated with the injection of waste water to the steam reservoir;

- The expiration or termination of our PPAs and the related results on revenues; and

- Other risks identified in this Report.

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

Where You Can Find Other Information

We file annual, quarterly and other reports, proxy statements and other information with the SEC. You may obtain and copy any document we file with the SEC at the SEC's public reference room at 100 F Street, NE, Room 1580, Washington, D.C. 20549. You may obtain information on the operation of the SEC's public reference facilities by calling the SEC at 1-800-SEC-0330. You can request copies of these documents, upon payment of a duplicating fee, by writing to the SEC at its principal office at 100 F Street, NE, Room 1580, Washington, D.C. 20549-1004. The SEC maintains an Internet website at http://www.sec.gov that contains reports, proxy and information statements, and other information regarding issuers that file electronically with the SEC. Our SEC filings, including exhibits filed herewith, are accessible through the Internet at that website.

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

PART I

Item 1. *Business*

BUSINESS AND STRATEGY

Business

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

We are the largest publicly traded, independent wholesale power company in the U.S. measured by power produced in the U.S. Our portfolio, including partnership interests, consists of 76 operating power plants, with an aggregate generation capacity of approximately 24,187 MW and two additional power plants totaling nearly 1,000 MW under construction or in advanced development. Our portfolio is comprised of two types of power generation technologies: natural gas-fired combustion turbines (primarily combined-cycle) and renewable geothermal conventional steam turbines. We generate 4,080 MW of baseload capacity from our Geysers Assets and Cogeneration power plants (natural gas-fired power plants that produce and sell both power and steam), 15,057 MW of intermediate load capacity from our combined-cycle combustion turbines and 5,050 MW of peaking capacity from our simple-cycle combustion turbines and duct-fired capability. Our Geysers Assets, located in northern California, produce approximately 725 MW and represent the largest geothermal power generation portfolio in the U.S. We have conformed our definition of operating power plants for our Geysers Assets in 2008 to match our remaining portfolio of power plants. We have 15 geothermal operating power plants with 17 steam turbines. Previously, we counted each of our 17 steam turbines as separate power plants.

Our power plants are located primarily in four regions: Texas with 7,487 MW of capacity, the West (including geothermal) with 7,246 MW, the Southeast with 6,104 MW and the North (including Canada) with 3,350 MW. Our fleet of natural gas-fired turbines is the youngest in the U.S. among large independent power producers and utilities, with an average age of about eight years. As a result, in the near term we do not expect that it will be necessary to invest in costly large replacement or reconstruction projects such as major retrofits to comply with air emissions or water regulations. In addition, our fleet has an effective Heat Rate lower than that of our major competitors, which we believe gives us a competitive edge in markets such as Texas, California and some northeastern states where natural gas-fired generation generally sets the market price for power.

The environmental profile of our power plants reflects our commitment to environmental stewardship. We have the lowest overall emissions of CO_2, SO_2, NOx and Hg per MWh generated among the major U.S. independent power producers. The combination of our Geysers Assets and our high efficiency portfolio of natural gas-fired power plants results in substantially lower emissions of these gases compared to our competitors' power plants using other fossil fuels, such as coal or oil. To condense steam, we use cooling towers with a closed water cooling system, or air cooled condensers and do not employ "once-through" water cooling which uses large quantities of water from adjacent waterways negatively impacting aquatic life. As a result of our efforts to reduce potentially harmful air emissions and to minimize our impact on water resources, we believe it will not be necessary in the near term to make substantial additional investments in costly environmental projects. We also believe that we will be less impacted by cap-and-trade limits, carbon tax, required environmental upgrades as a result of potential GHG or water regulations than our competitors who use other fossil fuels or steam condensation technologies.

We sell a substantial portion of our power and other products under PPAs with a duration greater than one year. The contracted sale of power, steam, capacity and renewable energy credits, which we refer to as RECs, from our Geysers Assets, Cogeneration plants and combustion turbine plants provide a stable source of revenues. Our portfolio also affords us the flexibility to sell power and other products forward for shorter terms, or on a merchant basis into the spot markets, where we are able to realize attractive pricing particularly during peak demand periods. Additionally, we sell capacity or similar products to retail power providers, utilities, municipalities and others required to acquire capacity and similar products by regulatory or market rules, and we sell ancillary services to independent system operators and utilities to support power transmission system reliability. With our combined forward power sales and natural gas purchases, we believe we have substantially hedged our gross Commodity Margin for 2009.

Strategy

We were established in 1984 for the purpose of developing, constructing, owning and operating a new generation of clean, reliable and efficient natural gas power plants as a participant in the newly emerging independent power industry. Our principal offices are located in Houston, Texas, and San Jose, California, although effective April 1, 2009, we intend to make Houston our sole headquarters and we intend to consolidate our San Jose and Pleasanton, California personnel into one new office in Dublin, California. We operate our business through a variety of divisions, subsidiaries and affiliates. We assess our business primarily on a regional basis due to the impact on our financial performance of the differing characteristics of these regions, particularly with respect to competition, regulation and factors impacting supply and demand. Our reportable segments are West (including geothermal), Texas, Southeast, North (including Canada) and Other. Our Other segment includes fuel management, TMG, certain non-region specific natural gas marketing and optimization, and other corporate activities.

In the second half of 2008, following our reorganization and emergence from Chapter 11 in January 2008, we successfully attracted a new and experienced executive team led by Jack Fusco, President and Chief Executive Officer; Thad Miller, Executive Vice President, Chief Legal Officer and Corporate Secretary and John (Thad) Hill, Executive Vice President and Chief Commercial Officer. We retained key long-term employees including Zamir Rauf, who was promoted to Executive Vice President and Chief Financial Officer. We believe that our newly strengthened executive management team possesses the vision, skills and experience necessary to lead our business and to drive long term shareholder value.

Our goal is to be recognized as the premier independent power company in the U.S. Our current challenge is to be a best-in-class operating company capable of achieving sustainable growth through financially disciplined power plant ownership, acquisition, development and construction. Our strategy to achieve this is reflected in the five major initiatives described below:

1. *Retain and Attract Skilled Employees* — We are engaged in a review and analysis of our organizational structure and compensation metrics in order to better align our employees' interests with those of our shareholders. Our objective is to identify and introduce further efficiencies into the corporate and operating organization and to take steps to retain and motivate key employees. Where necessary, we have recruited and intend to continue to recruit highly talented individuals to help us improve performance and increase our effectiveness. As an important step in this process, in January 2009 we completed an internal reorganization, eliminating a layer of management and clarifying reporting lines.

2. *Excellence in Operations* — We are engaged in a Company-wide effort aimed at increasing our return on invested capital through operational performance improvements within our power plants along with a

range of initiatives at regional and corporate offices to reduce expenses. At the power plant level, our initiatives will include the development and monitoring of key performance indicators that measure employee and contractor safety, reliability, generation, efficiency and station service utilization rates. At the regional and corporate office level, our initiatives will include the development and monitoring of key performance indicators that measure employee and contractor safety, productivity, effectiveness and expense reduction. We intend to use the full year 2008 results as a base year to measure our future performance.

3. *Optimize Our Existing Assets* — Our focus is on a comprehensive portfolio review encompassing asset and facility design, market expectations, potential upgrades or expansion opportunities and expected financial performance. We believe that investing in additional capacity at our existing power plants will be a financially disciplined and competitive means of achieving growth while deploying capital at attractive rates of return. Our comprehensive portfolio review may also result in the decision to divest underperforming assets.

4. *Expand Our Portfolio of Power Plants* — We intend to take an opportunistic approach to design, develop, construct and operate the next generation of highly efficient, operationally flexible and environmentally responsible power plants. Our goal is to continue to grow our presence in our core markets, particularly, our two largest markets, California and Texas, with an emphasis on expansions or upgrades of existing plants and we will consider selective acquisitions, or additions of new capacity supported by long-term hedging programs, including PPAs and natural gas tolling agreements, particularly where limited or non-recourse project financing is available.

5. *Leverage Our Expertise in Geothermal Operations* — The design, development, construction and operation of our steam fields and power plants at our Geysers Assets are a core competency of our highly skilled employees. We intend to use this expertise to focus on the expansion of our geothermal capability at The Geysers and elsewhere.

THE MARKET FOR POWER

Overview

The power industry represents one of the largest industries in the U.S. and impacts nearly every aspect of our economy, with an estimated end-user market comprising approximately $363.4 billion of power sales in 2008 based on information published by the EIA. Historically, vertically integrated power utilities with monopolistic control over franchised territories dominated the power generation industry in the U.S. However, industry trends and regulatory initiatives, culminating with the deregulation trend of the late 1990's and early 2000's, provided opportunities for independent wholesale power producers to compete to provide the power needed by customers. Although different regions of the country have very different models and rules of competition, all of the markets in which we operate have some form of wholesale market competition. Two of our largest markets, the West and Texas, have emerged as among the most competitive markets in the U.S.

We produce several products for sale to our customers.

- First, we produce power for sale to utilities, large end-use customers or power marketers.

- Second, we produce steam as a by-product of some of our power production for sale to customers for use in industrial or other heating, ventilation and air conditioning operations.

- Third, we sell regulatory capacity. In various regional markets, retail power providers are required to procure rights to existing power plants to demonstrate adequate resources to meet their power sales commitments (capacity). Electricity market administrators have acknowledged that the markets for generating capacity do not provide sufficient revenues to enable existing merchant generators to recover all of their costs or to encourage new generating capacity to be constructed. Capacity auctions have been implemented in the northeast, mid-Atlantic and some mid-west regional markets to address this issue. In addition, California has a bilateral capacity program. Texas does not have a capacity market and, although we are advocating for a capacity market there, no concrete proposal is under consideration by the regulators.

- Fourth, we provide ancillary service products to wholesale power markets. These products include the right for the purchaser to call on our generation units to provide flexibility to the market. As an example, we are sometimes paid to reserve a portion of some capacity at some of our units that could be deployed quickly should there be an unexpected increase in load.

- Fifth, we sell RECs from our Geysers Assets in northern California. California has an RPS that requires load serving entities to have RECs for a certain percentage of their demand for the purpose of guaranteeing a certain level of renewable generation in the state. Because geothermal is a renewable source of energy, we receive a REC for each MWh we produce and are able to sell our RECs to load serving entities.

Although all of the products mentioned above contribute to our financial performance, the most important is our sale of wholesale power.

Our Power Market Economics

Our Commodity Margin from power and steam sales is largely determined by the pricing associated with our customer contracts. For power that is not sold under customer contracts, the short-term and spot market supply and demand fundamentals determine the sale price for our power. All of our steam production is sold under long-term contracts with industrial customers or steam hosts.

For sales of power from our natural gas-fired fleet into the short-term or spot markets, we attempt to maximize our operations when the price of power is greater than the cost of the fuel required to generate power. Assuming economic behavior by market participants, generating units generally are dispatched in order of their variable costs, with units with lower costs being dispatched first and units with higher costs dispatched as demand, or "load," grows beyond the capacity of the lower cost units. For this reason, in a competitive market, the price of power typically is related to the operating costs of the marginal generator that is, the last unit to be dispatched in order to meet demand. Because our fleet is modern and more efficient than the average generation fleet, we run more and earn incremental margin in markets in which less efficient natural gas units frequently set the power price. In such cases, our margin is positively correlated with how much more efficient our fleet is than our competitors' fleets and with higher natural gas prices. Much of our generating capacity is in our West and Texas segments, which are regional markets in which natural gas-fired units set prices during most hours. Because natural gas prices generally are higher than most other input fuels for power production per MMBtu, these regions generally have higher power prices than regions where coal-fired units set power prices. However, outside of the West and Texas markets (and some northeast markets), other generating technologies, typically coal-fired plants, tend to set power prices more often, reducing average prices and our Commodity Margin.

Supply/Demand Fundamentals

Reserve margin, a measure of how much excess generation capacity is present in a market, is a key indicator of the competitive conditions in the markets in which we operate. For example, a reserve margin of 15% indicates that supply is 115% of expected peak power demand. Holding other factors constant, lower reserve margins typically lead to higher power prices because the less efficient capacity in the region would be needed to satisfy power demand. Markets with tight demand and supply conditions often display price spikes and improved bilateral contract opportunities. Typically, the market price impact of reserve margins is quantified in a "Market Heat Rate" calculated as the local market power price divided by the local natural gas price.

For much of the 1990's, utilities invested relatively sparingly in new generating capacity. As a result, by the late 1990's, many regional markets had low reserve margins and were in need of new capacity to meet growing power demand. Prices rose due to capacity shortages and the emerging merchant power industry responded by constructing significant amounts of new capacity. Between 2000 and 2003, more than 175,000 MW of new generating capacity came "on line" in the U.S. In most regions, these capacity additions far outpaced the growth of demand, resulting in "overbuilt" markets, that is, markets with excess capacity. In the West, for example, approximately 24,000 MW of new generating capacity was added between 2000 and 2003, while demand only increased by approximately 8,000 MW. This surge of generation investment subsided after 2003. There has been more recent, but smaller scale, investment in new generation capacity over the last several years. Reserve margins by NERC region in 2008 for each of our segments are listed below:

West:	
WECC	22.2%
Texas:	
ERCOT	16.5%
Southeast:	
SERC	16.9%
SPP	17.9%
North:	
NPCC	23.1%
MRO	15.6%
RFC	19.1%

The downturn in the economy and the conditions in the financial markets, including the consequent lack of availability of new capital, the uncertain expectations around load growth, the possibility of near-term decline in power demand, and overall lower energy commodity prices coupled with the potential for major changes in environmental laws and regulations for both water and air and the prospect of mandated levels of renewable energy production, make it very difficult to predict the evolution of the markets in the near term. For example, environmental legislation or regulation in Texas and California could have a material impact on the generation supply available to the market. In Texas, there are likely to be new ozone reduction implementation plans in Houston and other metropolitan areas early next decade. In California, greater restrictions on once-through cooling at power plants are under consideration. These developments in Texas and California could lead to the retirement or curtailment of older power plants that do not have appropriate existing controls or design.

Natural Gas Prices and Supply

Our fuel requirements are predominantly met with natural gas. We procure natural gas from multiple suppliers and transportation sources. Although availability is generally not an issue, localized shortages, transportation availability and supplier financial stability issues can and do occur.

Natural gas prices, which have been volatile in recent years, can have varying effects on our Commodity Margin. In markets where natural gas is the price-setting fuel, such as in Texas and the West, increases in natural gas prices may increase our Commodity Margin because our combined-cycle plants in those markets are more fuel-efficient than conventional gas-fired technologies and peaking units. Conversely, decreases in natural gas prices tend to decrease our Commodity Margin. In other cases, changes in natural gas prices can have a neutral impact on us, such as where we have entered into tolling agreements under which the customer provides the natural gas and in return we convert it to power for a fee, or where we enter into indexed-based agreements with a contractual Heat Rate at or near our actual Heat Rate for a monthly payment. Changes in natural gas prices may also affect our liquidity as we could be required to post additional cash collateral or letters of credit during periods of rising natural gas prices.

Hedging

We seek to actively manage the commodity price risk to our economic performance with a variety of tools, including the use of PPAs and other long-term contracts for both steam and power. We also pursue other long-term sales opportunities as well as shorter term market transactions, including bi-lateral originated sales contracts, and purchase and sale of exchange-traded instruments. We actively monitor key commodity price risks such as Market Heat Rate and natural gas price exposure, as well as other risks related to the value of our generation such as regulatory capacity, REC and emission credit pricing. The relative quantity of our products sold under longer term contracts compared to the quantity subject to shorter term price fluctuations is determined by our need to manage balance sheet risk, the availability of forward product sales opportunities, and our view of the attractiveness of the pricing available for forward sales. It is our strategy to seek stronger bi-lateral relationships and longer term contracts with load serving entities that can benefit us and our customers.

We provide more detail on our hedging programs in "— Marketing, Hedging and Optimization Activities" below.

COMPETITION

Wholesale power generation is a capital-intensive, commodity-driven business with numerous industry participants. We compete against other IPPs, trading companies, financial institutions, retail load aggregators, municipalities, retail power providers, cooperatives and regulated utilities to supply power and power-related products to our customers in major markets in the U.S. In addition, in some markets, we compete against some of our customers. It is uncertain given the recent financial crisis whether financial institutions, marketers and others that have participated in the power and natural gas markets will continue to participate in the market at the same levels as in the past or at all.

Generally, pricing for power can be influenced by a variety of factors, including the following:

- number of market participants buying and selling;
- amount of power normally available in the market;
- fluctuations in power supply due to planned and unplanned outages of generators;
- fluctuations in power demand due to weather and other factors;
- cost of fuel used by generators, which could be impacted by efficiency of generation technology and fluctuations in fuel supply or interruptions in natural gas transportation;
- relative ease or difficulty of developing and constructing new power plants;
- availability and cost of power transmission;
- creditworthiness and other risks associated with counterparties;
- bidding behavior of market participants;
- regulatory and independent system operator (ISO) guidelines and rules;
- structure of the commercial products transacted; and
- ability to optimize the market's mix of alternative sources of power such as renewable and hydroelectric power.

In less regulated markets, such as the West and Texas, our natural gas-fired power plants compete directly with all other sources of power. Even though most new power plants are fueled by natural gas, the EIA estimates that in 2008 only 22% of the power generated in the U.S. was fueled by natural gas and that approximately 67% of power generated in the U.S. was still produced by coal and nuclear facilities, which generated approximately 48% and 19%, respectively. The EIA estimates that the remaining 11% of power generated in the U.S. was fueled by hydroelectric, fuel oil and other energy sources. As environmental regulations continue to evolve, the proportion of power generated by natural gas and other low emissions resources is expected to increase in most markets. The federal government and some states and regions are considering or are imposing strict environmental standards on generators to limit their emissions of NOx, SO_2, Hg and GHG. As a result, many of the existing coal plants will likely have to install costly emission control devices or limit their operations. Meanwhile, the federal government and many states are considering or are mandating that certain percentages of power delivered to end users in their jurisdictions be produced from renewable resources, such as geothermal, wind and solar energy. The combination of emerging air emissions regulations and mandated renewable power standards could cause some coal plants to be retired, thereby allowing a greater proportion of power to be produced by facilities fueled by natural gas, geothermal or other resources that have a less adverse environmental impact. Conversely, the federal and some state governments are considering or have created financial and other incentives for renewable resources such as solar, wind and other alternative sources of power. This likely will increase competition over the longer term.

We believe our ability to compete effectively in this environment will be substantially driven by the extent to which we (i) maintain excellence in operations; (ii) achieve and maintain a lower cost of production, primarily by maintaining unit availability and efficiency; (iii) effectively manage and accurately assess our risk; and (iv) provide reliable service to our customers.

MARKETING, HEDGING AND OPTIMIZATION ACTIVITIES

The majority of our marketing, hedging and optimization activities are related to risk exposures that arise from our ownership and operation of power plants. Most of the power generated by our power plants is sold, scheduled and settled by our energy marketing unit, which sells to entities such as utilities, municipalities and cooperatives, as well as to retail power providers, commercial and industrial end users, financial institutions, power trading and marketing companies and other third parties. We enter into physical and financial purchase and sale transactions as part of our marketing, hedging and optimization activities. The marketing, hedging and optimization activities endeavor to protect or enhance our Commodity Margin.

We are one of the largest consumers of natural gas in the U.S. having consumed approximately 610.0 Bcf during 2008. We employ a variety of market transactions to satisfy most of our natural gas fuel requirements. We enter into long-term, short-term and spot natural gas purchase agreements as well as storage and transport agreements to achieve delivery flexibility and to enhance our optimization capabilities. We continually evaluate our natural gas needs, adjusting our natural gas position in an effort to minimize the delivered cost of natural gas, while adjusting for risk within the limitations prescribed in our commodity risk policy.

We are exposed to commodity price volatility in the markets in which our power plants operate. Natural gas prices and power prices are generally correlated in our two primary markets, the West and Texas, because plants using natural gas-fired technology tend to be the marginal or price-setting generation units in these regions. Holding other factors constant, where natural gas is the price-setting fuel, higher natural gas prices tend to increase our Commodity Margin because our combined-cycle plants are more fuel-efficient than many other older gas-fired technologies and peaking units. However, the positive relationship between natural gas prices and our Commodity Margin may be diminished by the effects of our fixed-price PPAs and where natural gas-fired units are not on the margin as is often the case in off-peak periods or in markets where non-gas-fired capacity can satisfy the majority of the demand. Our Geysers Assets do not consume natural gas, and because there is a direct relationship between power prices and natural gas prices in the West, increases in natural gas prices generally benefit our Geysers Assets.

We seek to actively manage the commodity price risks of our portfolio, utilizing multiple strategies of buying and selling power or natural gas to manage our spark spread, or selling Heat Rate transactions into the market, which results in a long commodity position. When the Market Heat Rate exceeds the cost for our plants to convert natural gas into power, we realize the long Heat Rate position.

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

Along with our portfolio of hedging transactions, we enter into power and natural gas positions that often act as hedges to our asset portfolio, but do not qualify as hedges under hedge accounting criteria guidelines, such as commodity options transactions and instruments that settle on power price to natural gas price relationships (e.g. Heat Rate swaps and options). Although our marketing, hedging and optimization transactions in power and natural gas are mostly physical in nature, we also engage in activities, particularly in natural gas, that are financial in nature.

We have VAR limits that govern the overall risk of our portfolio of power plants, energy contracts, financial hedging transactions and other contracts. Our VAR limits, transaction approval limits and other risk related controls are dictated by our commodity risk policy which is approved by our Board of Directors and by our Risk Management Committee comprised of members of our senior management and administered by our Chief Risk Officer and his organization. The Chief Risk Officer's organization is segregated from the commercial operations unit and reports directly to our Audit Committee and Chief Executive Officer. Our risk management policies limit our hedging activities to protect and optimize the value of our physical assets. While this policy limits our potential upside from hedging activities, it is primarily intended to provide us with a degree of protection from significant downside energy commodity price exposure to our cash flows.

During late 2008, a comprehensive review was conducted of our risk management policies. As a result of this review, a number of initiatives were implemented to improve governance. These initiatives included: (i) a reduction in individual risk authority limits below the executive level, (ii) introduction of additional VAR limits, (iii) a stronger emphasis on collateral efficient transactions, and (iv) implementation of additional types of limits for portfolios containing options. Our executive Risk Management Committee, based on input from our commercial operations group and risk management group, sets risk policy, including credit policy, and our Chief Risk Officer and Senior Vice President for Commercial Operations are responsible for the implementation and enforcement of these policies.

We actively monitor and hedge our portfolio exposure to future market risks. As of December 31, 2008, we have substantially hedged our forward fuel and power price risk for 2009 through the use of derivative financial and physical transactions. Our future hedged status is subject to change as determined by our commercial operations group, Chief Risk Officer, executive Risk Management Committee and our Board of Directors.

Seasonality and weather can have a significant impact on our results of operations and are also considered in our hedging and optimization activities. Most of our power plants are located in regional power markets where the greatest demand for power occurs during the summer months, which is our fiscal third quarter. Depending on existing contract obligations and forecasted weather and power demands, we may maintain either a larger or smaller open position on fuel supply and committed generation during the summer months so that we can enhance or protect our Commodity Margin accordingly.

SEGMENT AND SIGNIFICANT CUSTOMER INFORMATION

See Note 17 of the Notes to Consolidated Financial Statements for a discussion of financial information by reportable segment and sales in excess of 10% of our total revenues to one of our customers.

ENVIRONMENTAL PROFILE

A founding principal of our Company at its inception in 1984 and continuing today is our commitment to the generation of power in a cost effective and environmentally responsible manner. To achieve this we have assembled the largest fleet of combined-cycle natural gas-fired power plants and the largest fleet of geothermal power plants in North America.

We are committed to maintaining our fleet of clean, cost-effective and efficient power plants and to reducing our environmental impact though water conservation and the reduction of CO_2 emissions as well as emissions of other air pollutants. We also are committed to supporting policymakers on legislation to reduce emissions, and have been actively involved in the discussions and debates within the industry and with policymakers as GHG policies are developed. We were involved in the development and enactment of Assembly Bill 32 in California, and we have publicly supported RGGI in the northeast. In 2006, we were one of only two electric generating companies to file a brief of *amicus curiae* in support of the petitioners in the landmark case of *Commonwealth of Massachusetts, et al. v. U.S. Environmental Protection Agency*, in which the U.S. Supreme Court held that CO_2 was a pollutant potentially subject to the CAA. Our environmental record has been widely recognized: we are an EPA Climate Leaders Partner with a stated goal to reduce GHG emissions, we became the first power producer to earn the distinction of Climate Action Leader™, and we have certified our CO_2 emissions inventory with the California Climate Action Registry every year since 2003.

Natural Gas-Fired Generation. Our fleet consumes significantly less fuel to generate power than conventional boiler/steam turbine power plants and emits less air pollution into the environment per MWh of power produced as compared to coal-fired or oil-fired power plants. All of our natural gas-fired power plants have air emissions controls and most have selective catalytic reduction to further reduce emissions of nitrogen oxides, a known precursor of atmospheric ozone. In addition, we have implemented a program of proprietary operating procedures to reduce natural gas consumption and lower air pollutant emissions per MWh of power generated. The table below summarizes approximate air pollutant emission rates from our natural gas-fired power plants compared to the average emission rates from U.S. coal-, oil-, and gas-fired power plants as a group, based on the most recent statistics available to us.

	Air Pollutant Emission Rates—Pounds of Pollutant Emitted Per MWh of Power Generated		
Air Pollutants	**Average U.S. Coal-, Oil-, and Natural Gas-Fired Power Plant(1)**	**Calpine Natural Gas-Fired, Combined-Cycle Power Plant(2)**	**Compared to Average U.S. Coal-, Oil-, and Natural Gas-Fired Power Plant**
Nitrogen Oxide, NOx	2.72	0.20	92.8% less
Acid rain, smog and fine particulate formation			
Sulfur Dioxide, SO_2	6.71	0.0045	99.9% less
Acid rain and fine particulate formation			
Mercury, Hg	0.000035	—	100.0% less
Neurotoxin			
Carbon Dioxide, CO_2	1,863	790	57.6% less
Principal GHG—contributor to climate change			

(1) The average U.S. coal-, oil-, and natural gas-fired power plant's emission rates were obtained from the U.S. Department of Energy's Electric Power Annual Report for 2007. Emission rates are based on 2007 emissions and net generation. The U.S. Department of Energy has not yet released 2008 information.

(2) Our natural gas-fired power plant estimated emission rates are based on our 2007 emissions and power generation data as measured under the EPA reporting requirements.

Geothermal Generation. Our 725 MW fleet of geothermal power plants utilizes a natural, clean and renewable energy source, steam from the Earth's interior, to generate power. Since these power plants do not burn fossil fuel, they are able to produce power with negligible CO_2 (the principal GHG), NOx and SO_2 emissions. Compared to the average U.S. coal-, oil-, and gas-fired power plant, our Geysers Assets emit 99.9% less NOx, 99.9% less SO_2, and 96.2% less CO_2.

There are 18 active geothermal power plants located in The Geysers region of northern California. We own and operate 15 of them. We recognize the importance of our Geysers Assets and we are committed to extending, and possibly expanding, this renewable geothermal resource through the addition of new steam wells and wastewater recharge projects where clean, reclaimed wastewater from local municipalities is recycled into the geothermal resource where it is converted by the Earth's heat into steam for power production.

Climate Change. We believe that federal legislation imposing limits on emissions of CO_2 emissions and other GHG from power plants is likely to be passed in the next 24 months. We expect the federal legislation will take the form of a cap-and-trade program, although it is possible that it may take other forms, such as a carbon tax. It is also possible that the EPA could propose and implement limits on GHG emissions under the CAA.

Although new legislation or regulations under the CAA has not yet been enacted at the national level, several states and regional organizations are developing, or have already developed and implemented, state-specific or regional initiatives to reduce GHG emissions through mandatory programs, including RGGI in the northeast, which became operative in early 2009, and Assembly Bill 32 in California, where implementation plans are currently in progress.

Due to the relatively low GHG emission rates of our fleet, we believe we will face a lower compliance burden than some competitors, particularly coal-fired and oil-fired generators. In addition, we believe we are well positioned to benefit on a net basis from climate change initiatives. Our combined-cycle, natural gas-fired plants emit less than half the CO_2 per unit of power generated than a traditional coal-fired unit. Although our Geysers Assets do emit some emissions due to a natural geological process, the compliance burden compared to both coal-fired and natural gas-fired generation is expected to be minimal.

For a more complete discussion of federal, state and regional climate change legislative and regulatory initiatives and how they might affect us, see "—Governmental and Regulatory Matters — Climate Change and Related Legislation and Regulations."

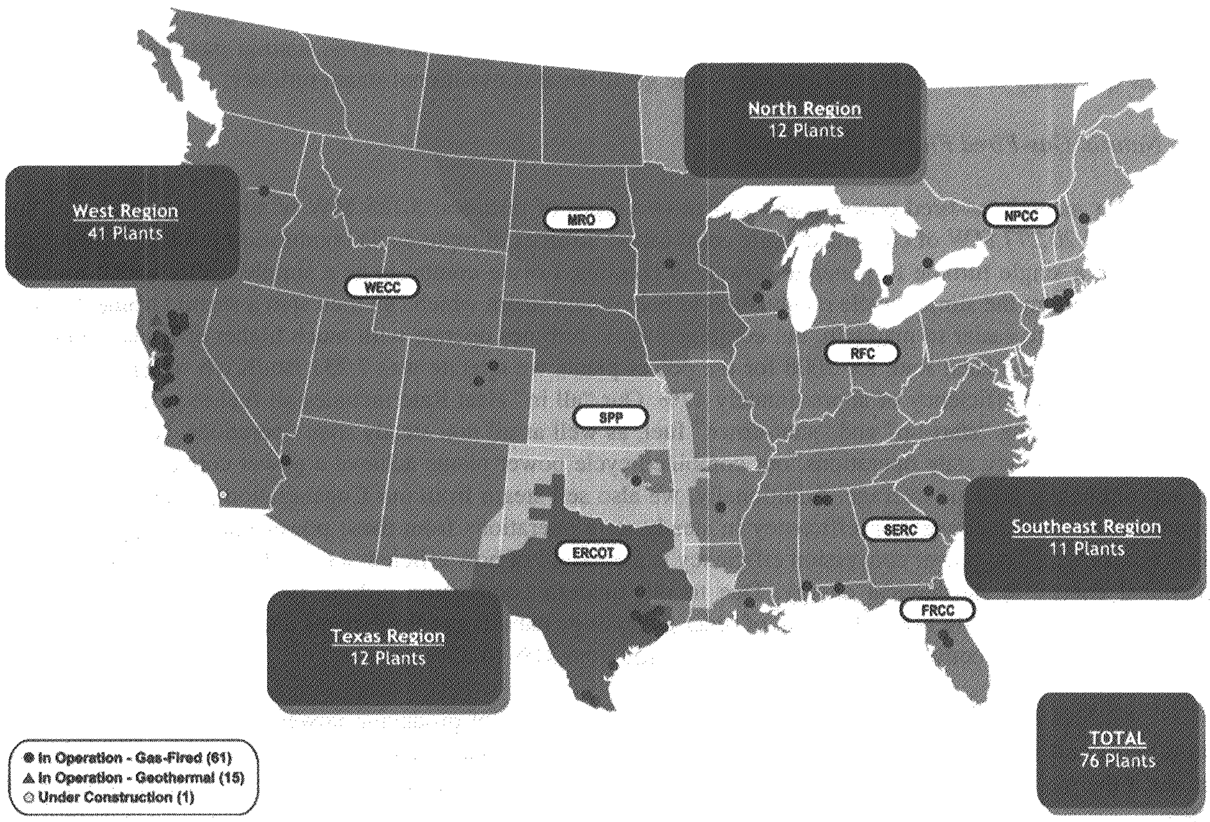
Water Conservation and Reclamation. We have also invested substantially in technologies and systems that reduce the impact of our operations on water as a natural resource:

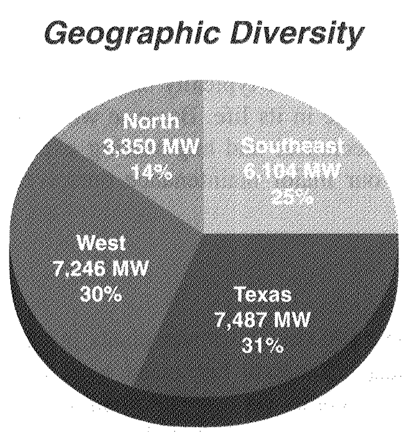
- The Santa Rosa Geysers Recharge Project, developed by us and the City of Santa Rosa, transports 11 million gallons of reclaimed water per day, wastewater that was previously being discharged into the Russian River, through a 41-mile pipeline from the City of Santa Rosa to our Geysers Assets, where it is recycled into the geothermal reservoir. The water is naturally heated by the Earth, creating additional steam to fuel our Geysers Assets.

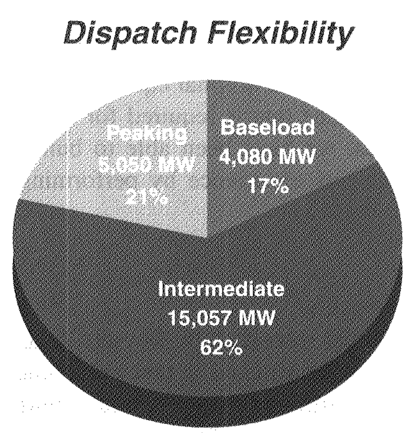
- We use cooling towers, which utilize a closed circuit water cooling system, or air cooled condensers to condense steam and do not employ once-through water cooling. Once-through water cooling, unlike our towers and condensers, uses large quantities of water from adjacent waterways, negatively impacting aquatic life.

- Through separate agreements with several municipalities where we use cooling towers, we use treated wastewater for cooling at several of our power plants. This eliminates the need to consume valuable surface and/or groundwater supplies, in the amount of three million to four million gallons per day for an average power plant.

DESCRIPTION OF OUR POWER PLANTS







Power Plants in Operation at December 31, 2008

We operate 76 power plants, with an aggregate operating generation capacity of approximately 24,187 MW. Our portfolio is comprised of two types of power generation technologies: natural gas-fired combustion turbines (primarily combined-cycle) and renewable geothermal conventional steam turbines.

Natural Gas-Fired Fleet

Our natural gas-fired power plants utilize two types of turbines: 3,185 MW of simple-cycle combustion turbines and 20,277 MW of combined-cycle combustion turbines. Simple-cycle combustion turbines burn natural gas to spin a single turbine to generate power. A combined cycle combusts as a simple cycle, which uses the exhaust heat from the simple-cycle combustion to help create steam which can then spin a steam turbine. Simple-cycle turbines are easier to maintain, but combined-cycle turbines operate with much higher efficiency. Our "all in" Steam Adjusted Heat Rate for 2008 for the power plants we operate was 7,231 Btu/KWh which results in a power conversion efficiency of approximately 47%. Our "all in" Heat Rate includes all fuel required to dispatch our plants including "start-up" and "shut-down" fuel, as well as all non-steady state operations. Once our power plants achieve steady state operations, our combined-cycle power plants achieve a power conversion efficiency of approximately 50% on average. Additionally, we also sell steam from our Cogeneration power plants, which improves our power conversion efficiency in steady state operations from these power plants to approximately 53% on average. The power conversion efficiency is a measure of how efficient a fossil fuel power plant converts chemical energy to mechanical energy. Due to our modern combustion turbine fleet, our power conversion efficiency is significantly better than that of older technology natural gas-fired plants and coal-fired plants, which typically have power conversion efficiencies that range from 31% to 36%.

Each of our power plants currently in operation is capable of producing power for sale to a utility, other third-party end user or an intermediary such as a marketing company. At some of our power plants we also produce thermal energy (primarily steam and chilled water), which can be sold to industrial and governmental users.

Our natural gas fleet is relatively young with an average unit age of approximately eight years. Taken as a portfolio, our natural gas units are among the most efficient in converting natural gas to power and emit far fewer pollutants than most typical legacy utility fleets. The age, scale, efficiency, and cleanliness of our units is a unique profile in the independent power sector.

The majority of the combustion turbines in the fleet are one of two technologies: GE 7FA's or Siemens 501FD's. We maintain our fleet through a regular and rigorous maintenance program. As units reach certain targets recommended by the original equipment manufacturer, which are typically based upon service hours, we perform the maintenance that is required for that unit at that stage in its life. Because we have a large fleet of similar technologies, we have been able to build significant technical and engineering experience with these units. We leverage this experience by performing much of our major maintenance ourselves with our TMG subsidiary.

Geothermal

Our geothermal resource, the Geysers Assets, is a 725 MW fleet of power plants in northern California. Geothermal power is considered a renewable energy because the steam harnessed to power our turbines is produced inside the Earth and does not require burning fuel to generate power. The steam is produced below the Earth's surface from reservoirs of hot water, both naturally occurring and injected. The steam is piped directly to the power plants through underground production wells and used to spin turbines to make power. In 2008, our Geysers Assets generated 6,020,599 MWh. Unlike other renewable resources such as wind or sunlight which depend on intermittent sources to generate power, making them less reliable, geothermal provides a consistent source of energy as evidenced by our Geysers Assets availability record of 97% in 2008.

The injected water, which extends the useful life of the resource and helps to maintain the output of our geothermal resources and power plants, comes from the condensate associated with the steam extracted to generate power, wells and creeks, as well as a water purchase agreement for reclaimed waste-water from the City of Santa Rosa Recharge Project and from Lake County.

We periodically obtain independent geothermal studies to help us assess the economic life of our geothermal reserves. Our most recent independent geothermal reserve study was conducted in 2006. Our evaluations of our geothermal reserves, including our review of any applicable independent studies conducted, indicate that the Geysers Assets should continue to supply sufficient steam to generate positive cash flows through 2050. In reaching this conclusion, our evaluation, consistent with the 2006 study, assumes that defined "proved reserves" are those quantities of geothermal energy which, by analysis of geological and engineering data, can be estimated with reasonable certainty to be commercially recoverable, from a given date forward, from known reservoirs and under current economic conditions, operating methods, and government regulations. We used as our "given date forward" our projected schedule of development, operation and investment for the period 2006 to 2050. Based upon that assumption and assumptions regarding our planned level of continued capital expenditures and reservoir replenishment activities, we forecast generation would decline to about 450 MW in 2050. This forecasted rate of decline includes the impact of water injection contracts, current decline rates and expected production and operating costs going forward.

We currently lease the geothermal steam fields from which we extract steam for our Geysers Assets. We have leasehold mineral interests in 107 leases comprising approximately 27,700 acres of federal, state and private geothermal resource lands in The Geysers region in northern California. Our leases cover one contiguous area of property that comprises approximately 40 square miles in the northwest corner of Sonoma County and southeastern corner of Lake County in northern California. The approximate breakout by volume of steam removed under the above leases for the year ended 2008 is:

- 28% related to leases with the federal government via the Minerals Management Service,
- 28% related to leases with the California State Lands Commission, and
- 44% related to leases with private landowners/leaseholders.

In general, our geothermal leases grant us the exclusive right to drill for, produce and sell geothermal resources from these properties and the right to use the surface for all related purposes. Each lease requires the payment of annual rent until commercial quantities of geothermal resources are established. After such time, the leases require the payment of minimum advance royalties or other payments until production commences, at which time production royalties are payable on a monthly basis from 10 to 31 days (depending upon the lease terms) following the close of the production month. Such royalties and other payments are payable to landowners, state and federal agencies and others, and vary widely as to the particular lease. In general, royalties payable are calculated based upon a percentage of total gross revenue received by us associated with our geothermal leases. Each lease's royalty calculation is based upon its percentage of revenue as calculated by its steam generated to the total steam generated by the Geysers Assets as a whole.

Our geothermal leases are generally for initial terms varying from 10 to 20 years or for so long as geothermal resources are produced and sold. A few of our geothermal leases were signed in excess of 30 years ago. Our federal leases are, in general, for an initial 10-year period with renewal clauses for an additional 40 years for a maximum of 50 years. The 50-year term expires in 2024 for the majority of our federal leases. However, our federal leases allow for a preferential right to renewal for a second 40-year term on such terms and conditions as the lessor deems appropriate if, at the end of the initial 40-year term, geothermal steam is being produced or utilized in commercial quantities. The majority of our other leases run through the economic life of the Geysers Assets and provide for renewals so long as geothermal resources are being produced or utilized, or are capable of being produced or utilized, in commercial quantities from the leased land or from land unitized with the leased land. Although we believe that we will be able to renew our leases through the economic life of the Geysers Assets on terms that are acceptable to us, it is possible that certain of our leases may not be renewed, or may be renewable only on less favorable terms.

In addition, we hold 41 geothermal leases comprising approximately 46,400 acres of federal geothermal resource lands in the Glass Mountain and Medicine Lake areas in northern California, which is separate from The Geysers region. Four test production wells were drilled prior to our acquisition and we have drilled one test well, which produced commercial quantities of steam during flow tests at our Glass Mountain leases. However, the properties subject to these leases have not been developed and are not producing properties. We have capitalized the costs associated with our test well; however, there can be no assurance that these leases will ultimately be developed. See Note 16 of the Notes to Consolidated Financial Statements for a description of litigation relating to our Glass Mountain area leases.

Table of Operating Power Plants and Projects Under Construction or in Advanced Development.

Set forth below is certain information regarding our operating power plants, and projects under construction or in advanced development as of December 31, 2008.

SEGMENT /Power Plant	NERC Region	U.S. State or Canadian Province	Technology	Baseload / Intermediate Capacity (MW)(1)	With Peaking Capacity (MW)(2)	Calpine Interest Percentage	Calpine Net Interest Baseload (MW)(3)	Calpine Net Interest With Peaking (MW)(3)	2008 Total MWh Generated(4)
WEST									
Geothermal									
McCabe #5 & #6	WECC	CA	Geothermal	78	78	100%	78	78	681,678
Ridge Line #7 & #8	WECC	CA	Geothermal	69	69	100%	69	69	600,707
Calistoga	WECC	CA	Geothermal	66	66	100%	66	66	555,133
Eagle Rock	WECC	CA	Geothermal	66	66	100%	66	66	512,842
Quicksilver	WECC	CA	Geothermal	53	53	100%	53	53	424,556
Cobb Creek	WECC	CA	Geothermal	52	52	100%	52	52	389,218
Lake View	WECC	CA	Geothermal	52	52	100%	52	52	427,362
Sulphur Springs	WECC	CA	Geothermal	51	51	100%	51	51	425,085
Socrates	WECC	CA	Geothermal	50	50	100%	50	50	406,347
Big Geysers	WECC	CA	Geothermal	48	48	100%	48	48	435,642
Grant	WECC	CA	Geothermal	43	43	100%	43	43	358,230
Sonoma	WECC	CA	Geothermal	42	42	100%	42	42	341,543
West Ford Flat	WECC	CA	Geothermal	24	24	100%	24	24	209,612
Aidlin	WECC	CA	Geothermal	17	17	100%	17	17	136,980
Bear Canyon	WECC	CA	Geothermal	14	14	100%	14	14	115,664
Natural Gas-Fired									
Delta Energy Center	WECC	CA	Natural Gas	818	840	100%	818	840	4,825,643
Pastoria Energy Center	WECC	CA	Natural Gas	750	750	100%	750	750	4,907,536
Rocky Mountain Energy Center	WECC	CO	Natural Gas	479	621	100%	479	621	3,275,882
Hermiston Power Project	WECC	OR	Natural Gas	547	616	100%	547	616	3,720,139
Metcalf Energy Center	WECC	CA	Natural Gas	564	605	100%	564	605	3,218,773
Sutter Energy Center	WECC	CA	Natural Gas	542	578	100%	542	578	2,898,990
Los Medanos Energy Center	WECC	CA	Natural Gas	512	540	100%	512	540	3,171,825
South Point Energy Center	WECC	AZ	Natural Gas	520	520	100%	520	520	2,719,436
Blue Spruce Energy Center	WECC	CO	Natural Gas	—	285	100%	—	285	407,519
Los Esteros Critical Energy Facility	WECC	CA	Natural Gas	—	188	100%	—	188	82,763
Gilroy Energy Center	WECC	CA	Natural Gas	—	135	100%	—	135	95,593
Gilroy Cogeneration Plant	WECC	CA	Natural Gas	117	128	100%	117	128	124,049
King City Cogeneration Plant	WECC	CA	Natural Gas	120	120	100%	120	120	473,153
Pittsburg Power Plant	WECC	CA	Natural Gas	64	64	100%	64	64	141,567
Greenleaf 1 Power Plant	WECC	CA	Natural Gas	50	50	100%	50	50	231,136
Greenleaf 2 Power Plant	WECC	CA	Natural Gas	49	49	100%	49	49	229,338
Wolfskill Energy Center	WECC	CA	Natural Gas	—	48	100%	—	48	25,849
Yuba City Energy Center	WECC	CA	Natural Gas	—	47	100%	—	47	35,373
Feather River Energy Center	WECC	CA	Natural Gas	—	47	100%	—	47	27,095
Creed Energy Center	WECC	CA	Natural Gas	—	47	100%	—	47	15,974
Lambie Energy Center	WECC	CA	Natural Gas	—	47	100%	—	47	16,780
Goose Haven Energy Center	WECC	CA	Natural Gas	—	47	100%	—	47	15,490
Riverview Energy Center	WECC	CA	Natural Gas	—	47	100%	—	47	29,609
King City Peaking Energy Center	WECC	CA	Natural Gas	—	45	100%	—	45	24,135
Watsonville (Monterey) Cogeneration Plant	WECC	CA	Natural Gas	29	29	100%	29	29	168,684
Agnews Power Plant	WECC	CA	Natural Gas	28	28	100%	28	28	233,965
Subtotal				5,914	7,246		5,914	7,246	37,136,895
TEXAS									
Freestone Energy Center	ERCOT	TX	Natural Gas	1,036	1,036	100%	1,036	1,036	3,771,858
Deer Park Energy Center	ERCOT	TX	Natural Gas	792	1,019	100%	792	1,019	5,536,774
Baytown Energy Center	ERCOT	TX	Natural Gas	742	830	100%	742	830	3,797,251
Pasadena Power Plant	ERCOT	TX	Natural Gas	731	776	100%	731	776	3,631,852
Magic Valley Generating Station	ERCOT	TX	Natural Gas	662	692	100%	662	692	3,230,295
Brazos Valley Power Plant	ERCOT	TX	Natural Gas	508	594	100%	508	594	2,886,726
Channel Energy Center	ERCOT	TX	Natural Gas	443	593	100%	443	593	2,720,564
Corpus Christi Energy Center	ERCOT	TX	Natural Gas	400	505	100%	400	505	2,417,748
Texas City Power Plant	ERCOT	TX	Natural Gas	400	453	100%	400	453	1,702,449
Clear Lake Power Plant	ERCOT	TX	Natural Gas	344	377	100%	344	377	800,152
Hidalgo Energy Center	ERCOT	TX	Natural Gas	475	479	78.5%	373	376	1,912,756
Freeport Energy Center(5)	ERCOT	TX	Natural Gas	210	236	100%	210	236	1,274,378
Subtotal				6,743	7,590		6,641	7,487	33,682,803

SEGMENT / Power Plant	NERC Region	U.S. State or Canadian Province	Technology	Baseload / Intermediate Capacity (MW)[1]	With Peaking Capacity (MW)[2]	Calpine Interest Percentage	Calpine Net Interest Baseload (MW)[3]	Calpine Net Interest With Peaking (MW)[3]	2008 Total MWh Generated[4]
SOUTHEAST									
Broad River Energy Center	SERC	SC	Natural Gas	—	847	100%	—	847	602,901
Morgan Energy Center	SERC	AL	Natural Gas	720	807	100%	720	807	2,321,249
Decatur Energy Center	SERC	AL	Natural Gas	734	792	100%	734	792	1,550,240
Columbia Energy Center	SERC	SC	Natural Gas	455	606	100%	455	606	355,453
Carville Energy Center	SERC	LA	Natural Gas	449	501	100%	449	501	1,871,170
Santa Rosa Energy Center	SERC	FL	Natural Gas	250	250	100%	250	250	18,359
Hog Bayou Energy Center	SERC	AL	Natural Gas	235	237	100%	235	237	142,254
Pine Bluff Energy Center	SERC	AR	Natural Gas	184	215	100%	184	215	1,246,759
Oneta Energy Center	SPP	OK	Natural Gas	980	1,134	100%	980	1,134	2,182,887
Osprey Energy Center	FRCC	FL	Natural Gas	537	599	100%	537	599	2,060,014
Auburndale Peaking Energy Center	FRCC	FL	Natural Gas	—	116	100%	—	116	22,521
Subtotal				4,544	6,104		4,544	6,104	12,373,807
NORTH									
Riverside Energy Center	MRO	WI	Natural Gas	518	603	100%	518	603	956,505
RockGen Energy Center	MRO	WI	Natural Gas	—	503	100%	—	503	77,137
Mankato Power Plant	MRO	MN	Natural Gas	280	324	100%	280	324	460,608
Westbrook Energy Center	NPCC / ISO NE	ME	Natural Gas	537	537	100%	537	537	2,606,896
Kennedy International Airport Power Plant	NPCC / NYISO	NY	Natural Gas	110	121	100%	110	121	512,808
Bethpage Energy Center 3	NPCC / NYISO	NY	Natural Gas	80	80	100%	80	80	303,855
Bethpage Power Plant	NPCC / NYISO	NY	Natural Gas	55	56	100%	55	56	122,981
Bethpage Peaker	NPCC / NYISO	NY	Natural Gas	—	48	100%	—	48	42,714
Stony Brook Power Plant	NPCC / NYISO	NY	Natural Gas	45	47	100%	45	47	269,273
Whitby Cogeneration[6]	Ontario	ON	Natural Gas	50	50	50%	25	25	135,322
Greenfield Energy Centre[7]	Ontario	ON	Natural Gas	775	1,005	50%	388	503	235,249
Zion Energy Center	RFC	IL	Natural Gas	—	503	100%	—	503	116,462
Subtotal				2,450	3,877		2,038	3,350	5,839,810
Total operating power plants (76)				**19,651**	**24,817**		**19,137**	**24,187**	**89,033,315**
Project under construction									
Otay Mesa Energy Center[8]	WECC	CA	Natural Gas	510	596	100%	510	596	n/a
Project in advanced development									
Russell City Energy Center	WECC	CA	Natural Gas	557	600	65%	362	390	n/a
Total operating power plants, and projects				**20,718**	**26,013**		**20,009**	**25,173**	

(1) Capacities are based on as-built as-designed outputs and do not factor in the typical MW loss and recovery profiles over time, which natural gas-fired turbine power plants display associated with their planned major maintenance schedules.

(2) Peaking capacity includes, where installed: (i) natural gas-fired turbine inlet air cooling; (ii) heat recovery system steam generator duct-firing; (iii) natural gas-fired turbine power augmentation; and/or (iv) optimization programs which temporarily allow for increased output at elevated turbine firing temperatures.

(3) Represents respective baseload capacity and peaking capacity multiplied by our equity interest in the power plant.

(4) MWh generation is shown here as our net operating interest. Excludes Auburndale Power Plant's 446,063 MWh generation for 2008 prior to its sale. (see Note 5 of the Notes to Consolidated Financial Statements).

(5) Freeport Energy Center is owned by us but contracted and operated by The Dow Chemical Company (DOW).

(6) We hold a 50% interest in Whitby Cogeneration; however, it is operated by Atlantic Packaging Products Ltd.

(7) We hold a 50% interest in Greenfield Energy Centre; however, it is operated by Mitsui & Co., Ltd. (see Note 5 of the Notes to Consolidated Financial Statements).

(8) Otay Mesa Energy Center was deconsolidated in the second quarter of 2007 (see Note 5 of the Notes to Consolidated Financial Statements).

We provide O&M services for all but two of the power plants in which we have an interest. Such services include the operation of power plants, geothermal steam fields, wells and well pumps and natural gas pipelines. We also supervise maintenance, materials purchasing and inventory control, manage cash flow, train staff and prepare O&M manuals for each power plant that we operate. As a power plant develops an operating history, we analyze its operation and may modify or upgrade equipment, or adjust operating procedures or maintenance measures to enhance the power plant's reliability or profitability.

Certain power plants in which we have an interest have been financed primarily with project financing that is structured to be serviced out of the cash flows derived from the sale of power (and, if applicable, thermal energy and capacity) produced by such power plants and generally provides that the obligations to pay interest and principal on the loans are secured solely by the capital stock or partnership interests, physical assets, contracts and/or cash flows attributable to the entities that own the power plants. The lenders under these project financings generally have no recourse for repayment against us or any of our assets or the assets of any other entity other than foreclosure on pledges of stock or partnership interests and the assets attributable to the entities that own the power plants. However, defaults under such project financings may result in cross-defaults to certain of our other debt, and under certain of our debt instruments, including our Exit Credit Facility. Acceleration of the maturity of a project financing following a default may result in a cross-acceleration of such other debt.

Substantially all of the power plants in which we have an interest are located on sites which we own or lease on a long-term basis.

Projects Under Construction and In Advanced Development at December 31, 2008

The development and construction of power generation projects involves numerous elements, including evaluating and selecting development opportunities, designing and engineering the project, obtaining PPAs in some cases, acquiring necessary land rights, permits and fuel resources, obtaining financing, procuring equipment and managing construction. We generally expect to start development or construction on new projects only in cases where power contracts and financing are available and attractive returns are expected.

Otay Mesa Energy Center. In July 2001, we acquired OMEC and the associated development rights including a California Energy Commission license permitting construction of the plant. Site preparation activities for this 596 MW natural gas-fired power plant, located in southern San Diego County, California began in 2001. In May 2007, we entered into a ten-year PPA with SDG&E for delivery of the full plant output of capacity and power beginning in May 2009; however, deliveries of power are expected to begin in the fall of 2009 due to construction delays. At the end of the ten-year PPA term, OMEC has an option to require SDG&E to purchase the plant and SDG&E has an option to require OMEC to sell the plant to SDG&E.

Russell City Energy Center. This is a proposed 600 MW, natural gas-fired power plant to be located in Hayward, California. In September 2006, we sold a 35% equity interest in the project to ASC for approximately $44 million and ASC's obligation to post a $37 million letter of credit. We own the remaining 65% interest. Under the LLC agreement with ASC, ASC's equity is to be applied toward completion of development and construction of the power plant, and ASC is also to provide related credit support for the project.

The Russell City Energy Center is currently contracted to deliver its full output to PG&E under a PPA which was executed in December 2006 and approved by the CPUC in January 2007. The PPA was amended in 2008 and is now before the CPUC for approval as amended. All permits for the projects have been issued and approved with the exception of an air permit now pending before the local air quality board. Under the amended PPA, the expected commercial operation date has been extended by two years from 2010 to June 2012. Completion of the Russell City Energy Center is dependent upon obtaining the necessary permits, regulatory approvals, construction contracts and construction funding under project financing facilities. We do not expect the costs to complete the Russell City Energy Center to be material to us on a consolidated basis.

GOVERNMENTAL AND REGULATORY MATTERS

We are subject to complex and stringent energy, environmental and other governmental laws and regulations at the federal, state and local levels in connection with the development, ownership and operation of our power plants. Federal and state legislative and regulatory actions continue to change how our business is regulated. Such changes could have positive or negative impacts on our existing business.

Climate Change and Related Legislation and Regulations

As a clean energy provider, we believe that we are well positioned on a net basis for potential regulation of GHG emissions. The federal government is expected to take action on climate change legislation in the near future, and many states and regions in the U.S. have implemented or are considering implementing regulations to reduce GHG emissions. In 2007, our emissions of CO_2 amounted to about 41 million tons. Although we cannot predict the ultimate effect any future climate change legislation or regulations could have on our business, we believe we face a lower compliance burden than some of our competitors due to the relatively low GHG emission rates of our fleet.

Related to climate change initiatives and also driven by national energy security, fiscal stimulus and more general environmental concerns, are proposals by the federal and state governments for renewable energy portfolio standards. It is too early to determine whether or not the enactment of a national RPS will have a positive or negative impact on us.

Proposed Federal Climate Change Legislation

We have been longtime supporters of regulating GHG emissions through a national, mandatory, comprehensive regulatory system. Although there are no federal laws regulating GHG emissions, there has been increased attention to climate change and the U.S. President Barack Obama has stated his support for a federal, economy-wide cap-and-trade program to significantly reduce GHG emissions. Similarly, U.S. Congressional leaders have stated their intention to pass legislation to regulate GHG emissions in this Congress, making climate change initiatives an emerging priority on the legislative and regulatory front. We are actively participating in the debates surrounding federal regulation of GHG emissions from the power generating sector, and we will endeavor to secure policies that recognize and reward our clean, efficient power plants.

Federal Regulation of GHG under Existing Law

Twelve states and various environmental groups filed suit against the EPA in *Commonwealth of Massachusetts, et al. v. U.S. Environmental Protection Agency* seeking confirmation that the EPA has an existing obligation to regulate GHG under the CAA. The EPA refused to regulate GHG emissions from motor vehicles on the basis that the CAA did not allow regulation of GHG emissions by the EPA including CO_2, as pollutants. In July 2005, the U.S. Court of Appeals for the District of Columbia Circuit ruled in favor of the EPA. The case was appealed to the U.S. Supreme Court. On April 2, 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate GHG issues under language included in the CAA. On July 11, 2008, the EPA released an Advance Notice of Proposed Rulemaking inviting public comment on the benefits and ramifications of regulating GHG emissions under the CAA. With the Obama Administration taking office in January 2009, the direction or timing of this process is uncertain.

Regional and State Climate Change Activities

Several states and regional organizations are developing, or already have developed, state-specific or regional initiatives to reduce GHG emissions through mandatory programs. The most advanced programs relate to actions taken by a coalition of northeast states, and regulations regarding renewable energy and climate change in California. The evolution of these programs could have a material impact on our business.

On January 1, 2009, ten northeast and mid-Atlantic states implemented a cap-and-trade program, RGGI, that affects our power plants in Maine, New York and New Jersey (together emitting about 1.7 million tons of CO_2 annually). RGGI caps regional CO_2 emissions and requires generators to acquire one allowance for every ton of CO_2 emitted over a three-year compliance period. Apart from state-specific set-asides and other factors, the vast majority of the region's CO_2 allowances are distributed to the market via public auction. RGGI auctions were held in September and December 2008, with clearing prices in the low $3 per ton range for 2009 vintage allowances. We are required to purchase allowances by buying them in RGGI public auctions or via the secondary market, or by investment in qualified offsets, to cover CO_2 emissions from our facilities in the RGGI region. The implementation of RGGI in New York was challenged following its launch on the basis, among others, that unlike the other participating states, New York had not obtained statutory authorization from the state legislature but had acted exclusively through the executive. RGGI continues in effect while this litigation is pending. We anticipate a neutral to positive business impact from RGGI, given the efficiency of our power plants in RGGI states.

California's Assembly Bill 32 and Senate Bill 1368 were signed into law in September 2006. Assembly Bill 32 creates a statewide cap on GHG emissions and requires the state to return to 1990 emission levels by 2020. Implementation is slated to begin in 2012. California regulators and industry participants continue to work on the regulations to implement Assembly Bill 32. We are an active participant in the development of these regulations.

Our other power plants may also become subject to state or regional CO_2 compliance requirements. The WCI, launched in February 2007, is a collaboration of seven U.S. Governors and four Canadian Premiers to reduce GHG emissions and could affect our power plants in California, Arizona, Oregon and Ontario. The WCI's goal is to establish a multi-sector cap-and-trade program effective for most sectors of the economy by 2012 and regulation of the transportation sector by 2015.

Florida is involved in ongoing rulemaking proceedings to develop a cap-and-trade program that may involve a state-specific approach or joining a regional program. Our two power plants in Florida could be affected by such action. Several states in the upper midwest are also considering actions to regulate power plant CO_2 emissions, either by themselves or through participation in the Midwestern Greenhouse Gas Reduction Accord. Our power plants in Illinois, Minnesota and Wisconsin could be affected by such action.

Renewable Portfolio Standards

Policy makers have been considering RPS at the federal and state level. Generally, an RPS requires each retail seller of electricity to include in its resource portfolio (the resources procured by the retail seller to supply its retail customers) a certain amount of electricity from renewable energy resources by a certain date. There is currently no national RPS, but there is a high probability that one will be implemented in 2009. President Obama has stated his goal is to have 10% of the nation's electricity provided from renewable sources by 2012, and 25% by 2025. U.S. Congressional leaders have committed to pass legislation to enact a national RPS in this Congress. It is too early to determine whether or not the enactment of a national RPS will have a positive or negative impact on us. Depending on the RPS structure, an RPS could enhance the value of our existing Geysers Assets. However, an RPS would likely initially drive up the number of wind and solar resources, which could negatively impact the dispatch of our natural gas assets, primarily in Texas and California. Conversely, our natural gas plants could benefit by providing complementary/back-up service for these intermittent renewable resources.

California is currently considering a range of options for a new and higher RPS. California's existing RPS requires certain retail power providers to generate or procure 20% of the power they sell to retail customers from renewable resources by 2010. A more aggressive 33% goal has been established (but is not mandatory) by several California state agencies, the Governor's office and other state officials. Similarly, the California Air Resources Board may require retail power sellers to meet a 33% RPS by 2020 pursuant to its authority under the state's GHG law, Assembly Bill 32. Legislation to increase the RPS to 33% and expand the requirements to all retail sellers, including municipalities, failed in the 2007-08 legislative session, but the concept is expected to be reintroduced in legislation in the 2009-10 session.

A number of additional states have RPS in place. These include Maine, Minnesota, New York, Texas and Wisconsin. Individual programs vary widely. Maine has the most stringent RPS, requiring retail providers to supply no less than 30% of their needs with qualified renewable resources. Other states, such as Texas, have a capacity-based standard that requires a specific amount of new renewable generation to be installed per year. Existing state-specific RPS requirements may change due to regulatory and/or legislative initiatives, and other states may consider implementing enforceable RPS in the future.

Other Environmental Regulations

Our power plants and the equipment necessary to support them are subject to extensive federal, state and local laws and regulations adopted for the protection of the environment and to regulate land use. The laws and regulations applicable to us primarily involve the discharge of emissions into the water and air, and the use of water, but can also include wetlands preservation, endangered species, hazardous materials handling and disposal, waste disposal and noise regulations. Noncompliance with environmental laws and regulations can result in the imposition of civil or criminal fines or penalties. In some instances, environmental laws also may impose clean-up or other remedial obligations in the event of a release of pollutants or contaminants into the environment. The following federal laws are among the more significant environmental laws that apply to us. In most cases, analogous state laws also exist that may impose similar and, in some cases, more stringent requirements on us than those discussed below. Our general policy with respect to these laws attempts to take advantage of our relatively clean portfolio of power plants as compared to our competitors.

Clean Air Act

The CAA provides for the regulation of air quality and air emissions, largely through state implementation of federal requirements. We believe that all of our operating power plants comply with federal and state performance standards mandated under the CAA.

Acid Rain Program

As a result of the 1990 CAA amendments, the EPA established a cap-and-trade program for SO_2 emissions from power generating units throughout the U.S. Starting with Phase II of the program in 2000, a permanent ceiling (or cap) was set at 10 million tons per year, declining to 8.95 million tons per year by 2010. The EPA allocated SO_2 allowances to power generators. Each allowance permits a unit to emit one ton of SO_2 during or after a specified year, and allowances may be bought, sold or banked. All but a small percentage of allowances were allocated to power plants placed into service before 1990. None of our power plants receive free

SO_2 allowances, so we must purchase allowances to cover all SO_2 emissions from our affected power plants and satisfy our compliance obligations. Since our entire fleet emits about 200 tons of SO_2 per year, we believe that our compliance expense for this program will be relatively insignificant compared with many of our competitors.

NOx State Implementation Plan Call

In response to concerns about interstate contributions to ozone concentrations above the NAAQS, the EPA promulgated regulations establishing a cap-and-trade program for NOx emissions from power generating and industrial steam generating units in most of the eastern U.S. in May 2004. Under these regulations, the EPA set a NOx emissions cap for each state and each affected unit receives NOx emissions allowances through allocation mechanisms that vary by state. Emission compliance obligations apply during the ozone season, which extends from May through September. If an affected unit exceeds its allocated allowances, it must purchase additional allowances to resolve the shortfall.

We own and operate numerous power plants that are affected by this program. To date, NOx allowance allocations have been sufficient to cover all emissions and we have sold some surplus allowances for a small profit. We believe that the relatively low NOx emission rate of our fleet in general keeps our compliance costs for this program lower than those of many of our competitors. This program will be replaced by CAIR in 2009.

Clean Air Interstate Rule

The EPA promulgated the CAIR regulations in March 2005, applicable to 28 eastern states and the District of Columbia, to facilitate attainment of its ozone and fine particulates standards issued in 1997. When fully implemented, CAIR would have reduced SO_2 emissions in these states by over 70%, and NOx emissions by over 60% from 2003 levels by 2015. CAIR establishes annual cap-and-trade programs for SO_2 and NOx as well as a seasonal program for NOx. On July 11, 2008, a panel of the U.S. Court of Appeals for the D.C. Circuit invalidated CAIR, stating that "EPA's approach — region-wide caps with no state specific quantitative contribution determinations or emission requirements — is fundamentally flawed." The court did not overturn the existing cap-and-trade program for SO_2 reductions under the Acid Rain Program or the existing ozone season cap-and-trade program under the NOx State Implementation Plan Call. On September 25, 2008, the EPA petitioned the court for rehearing. On December 23, 2008, the court remanded the CAIR rule without vacatur for the EPA to conduct further proceedings consistent with the July 11, 2008, opinion. As a result of the court's decision, CAIR was left intact and went into effect as planned on January 1, 2009, for many of our power plants located throughout the eastern and central U.S. Due to favorable allowance allocations, particularly in Texas, we have a net surplus of annual NOx allowances and the net financial impact of the program to our operations will be positive. The court did not set a definitive deadline for re-promulgation of a new rule. At this time, we cannot predict what action the EPA will take in response to this decision and the timing of such action, or the ultimate impact on us from these actions.

Houston/Galveston Nonattainment

Regulations adopted by the TCEQ to attain the one-hour and eight-hour NAAQS for ozone included the establishment of a cap-and-trade program for NOx emitted by power generating facilities in the Houston/Galveston ozone nonattainment area. We own and operate seven power plants that participate in this program, all of which received free NOx allowances based on historical operating profiles.

At this time, our Houston-area power plants have sufficient NOx allowances to meet forecasted obligations under the program. However, the TCEQ may modify future allocations of NOx in support of efforts to comply with the eight-hour ozone NAAQS. Should allowance shortfalls occur, we would be required to purchase NOx allowances or install emissions control equipment on certain power plants.

The EPA approved a request from the TCEQ to reclassify the Houston-Galveston-Brazoria region as a severe nonattainment area for the 8-hour ozone NAAQS. TCEQ is in the process of revising the state implementation plan and control measures are expected to be phased in beginning in the 2013 timeframe after the new rules become final in 2010. TCEQ is considering significant additional NOx and volatile organic compound control measures to achieve the necessary emissions reductions.

Clean Water Act

The federal Clean Water Act establishes rules regulating the discharge of pollutants into waters of the U.S. We are required to obtain wastewater and storm water discharge permits for wastewater and runoff, respectively, from certain of our power plants. We are required to maintain a spill prevention control and countermeasure plan with respect to certain of our natural gas power plants. We believe that we are in material compliance with applicable discharge requirements of the federal Clean Water Act.

Safe Drinking Water Act

Part C of the Safe Drinking Water Act established the underground injection control program that regulates the disposal of wastes by means of deep well injection, which is used for geothermal production activities. With the passage of EPAct 2005, oil, gas and geothermal production activities are exempt from the underground injection control program under the Safe Drinking Water Act.

Resource Conservation and Recovery Act

RCRA regulates the management of solid and hazardous waste. With respect to our solid waste disposal practices at the power generation facilities and steam fields located in The Geysers region of northern California, we are also subject to certain solid waste requirements under applicable California laws. We believe that our operations are in material compliance with RCRA and all such laws.

Comprehensive Environmental Response, Compensation and Liability Act

CERCLA, also referred to as Superfund, requires cleanup of sites from which there has been a release or threatened release of hazardous substances and authorizes the EPA to take any necessary response action at Superfund sites, including ordering potentially responsible parties liable for the release to pay for such actions. Potentially responsible parties are broadly defined under CERCLA to include past and present owners and operators of, as well as generators of wastes sent to, a site. As of the present time, we are not subject to any material liability for any Superfund matters. However, we generate certain wastes, including hazardous wastes, and send certain of our wastes to third party waste disposal sites. As a result, there can be no assurance that we will not incur liability under CERCLA in the future.

Federal Regulation of Power

FERC Jurisdiction

Electric utilities have been highly regulated by the federal government since the 1930s, principally under the FPA and PUHCA 1935. These statutes have been amended and supplemented by subsequent legislation, including PURPA, EPAct 1992 and EPAct 2005. These particular statutes and regulations are discussed in more detail below.

The FPA grants the federal government broad authority over electric utilities and IPPs, and vests its authority in FERC. Unless otherwise exempt, any person that owns or operates facilities used for the wholesale sale or transmission of power in interstate commerce is a public utility subject to FERC's jurisdiction. FERC governs, among other things, the disposition of certain utility property, the issuance of securities by public utilities, the rates, terms and conditions for the transmission or wholesale sale of power in interstate commerce, interlocking directorates, and the uniform system of accounts and reporting requirements for public utilities.

The majority of our power plants are subject to FERC's jurisdiction, but some qualify for available exemptions. FERC's jurisdiction over EWGs under the FPA applies to the majority of our power plants because they are EWGs or are owned by EWGs, except our EWGs located in ERCOT. Power plants located in ERCOT are exempt from many FERC regulations under the FPA. Many of our power plants that are not EWGs are operated as QFs under PURPA. Several of our affiliates have been granted authority to engage in sales at market-based rates and blanket authority to issue securities, and have also been granted certain waivers of FERC reporting and accounting regulations available to non-traditional public utilities; however, we cannot assure that such authorities or waivers will not be revoked for these affiliates or will be granted in the future to other affiliates.

FERC has the right to review books and records of "holding companies," as defined in PUHCA 2005, that are determined by FERC to be relevant to the companies' respective FERC-jurisdictional rates. We are considered a holding company, as defined in PUHCA 2005, by virtue of our control of the outstanding voting securities of our subsidiaries that own or operate power plants used for the generation of power for sale, or that are themselves holding companies. However, we are exempt from FERC's inspection rights pursuant to one of the limited exemptions under PUHCA 2005 because we are a holding company due solely to our owning one or more QFs, EWGs and FUCOs. If any single Calpine entity were not a QF, EWG or FUCO, then we and our holding company subsidiaries would be subject to the books and records access requirement.

FERC's policies and proposals will continue to evolve, and FERC may amend or revise them, or may introduce new policies or proposals in the future. The impact of such policies and proposals on our business is uncertain and cannot be predicted at this time.

FERC Regulation of Market-Based Rates

Under the FPA and FERC's regulations, the wholesale sale of power at market-based or cost-based rates requires that the seller have authorization issued by FERC to sell power at wholesale pursuant to a FERC-accepted rate schedule. FERC grants market-based rate authorization based on several criteria, including a showing that the seller and its affiliates lack market power in generation and transmission, that the seller and its affiliates cannot erect other barriers to market entry and that there is no opportunity for abusive transactions involving regulated affiliates of the seller. All of our affiliates that own domestic power plants (except for some of those power plants that are QFs under PURPA, or those that are located in ERCOT), as well as our market-based rate companies, are currently authorized by FERC to make wholesale sales of power at market-based rates. This authorization could possibly be revoked for any of our market-based rate companies if they fail to continue to satisfy FERC's current or future criteria, or if FERC eliminates or restricts the ability of wholesale sellers of power to make sales at market-based rates.

FERC's regulations specifically prohibit the manipulation of the power markets by making it unlawful for any entity in connection with the purchase or sale of power, or the purchase or sale of power transmission service under FERC's jurisdiction, to engage in fraudulent or deceptive practices.

To ward against market manipulation, FERC requires us and other sellers making sales pursuant to their market-based rate authority to file certain reports, including quarterly reports of contract and transaction data, notices of any change in status and triennial updated market power analyses. If a seller does not timely file these reports or notices, FERC can revoke the seller's market-based rate authority. FERC's regulations also contain four market behavior rules that apply to sellers with market-based rate authority. These rules address such matters as compliance with organized RTO or ISO market rules, communication of accurate information, price reporting to publishers of power or natural gas price indices, and record retention. Failure to comply with these regulations can lead to sanctions by FERC, including penalties and suspension or revocation of market-based rate authority.

FERC Regulation of Transfers of Jurisdictional Facilities

Dispositions of our jurisdictional facilities or certain types of financing arrangements may require prior FERC approval, which could result in revised terms or impose additional costs, or cause a transaction to be delayed or terminated. Pursuant to Section 203 of the FPA, as amended by EPAct 2005, a public utility must obtain authorization from FERC before the public utility is permitted to: sell, lease or dispose of FERC-jurisdictional facilities with a value in excess of $10 million; merge or consolidate facilities with those of another entity; or acquire any security or securities with a value in excess of $10 million issued by another public utility. FERC's prior approval is also required for transactions involving certain transfers of existing generation facilities and certain holding companies' acquisitions of facilities with a value in excess of $10 million. FERC's regulations implementing Section 203 of the FPA provide blanket authorizations for certain types of transactions, including acquisitions by holding companies that are holding companies solely due to their ownership, directly or indirectly, of one or more QFs, EWGs and FUCOs, to acquire additional QFs, EWGs or FUCOs, or the securities of additional QFs, EWGs and FUCOs without prior FERC approval.

FERC Regulation of Qualifying Facilities

Cogeneration and certain small power production facilities are eligible to be QFs under PURPA, provided that they meet certain power and thermal energy production requirements, and efficiency standards. QF status provides an exemption from PUHCA 2005 and grants certain other benefits to the QF, including, in some cases, the right to sell power to utilities at the utilities' avoided cost. Certain types of sales by QFs are also exempt from FERC regulation of wholesale sales of the QFs' power output. QFs are also exempt from most state laws and regulations. To be a QF, a Cogeneration power plant must produce power and useful thermal energy for an industrial or commercial process, or heating or cooling applications in certain proportions to the power plant's total energy output, and must meet certain efficiency standards.

An electric utility may be relieved of the mandatory purchase obligation to purchase power from QFs at the utility's avoided cost if FERC determines that such QFs have access to a competitive wholesale power market.

FERC Enforcement Authority

FERC has civil penalty authority over violations of any provision of Part II of the FPA, as well as any rule or order issued thereunder. FERC is authorized to assess a maximum civil penalty of $1 million per violation for each day that the violation continues. The FPA also provides for the assessment of criminal fines and imprisonment for violations under Part II of the FPA. This penalty authority was enhanced in EPAct 2005. With this expanded enforcement authority, violations of the FPA and FERC's regulations could potentially have more serious consequences than in the past.

NERC Compliance Requirements

Pursuant to EPAct 2005, NERC has been certified by FERC 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. Monetary penalties of up to $1 million per day per violation may be assessed for violations of the reliability standards. Certain electric reliability standards which apply to us as a generator owner, generator operator or marketer of power are effective and mandatory. In addition, the regional reliability organizations have the ability to formulate additional reliability standards to apply in their specific regions, which are required to supplement and be more stringent than the NERC reliability standards. It is possible that we will have to comply with different reliability standards and requirements in each region in which we operate. It is expected that additional NERC and regional reliability standards will be approved by FERC in the coming years requiring us to take additional steps to remain fully compliant.

Regional and State Regulation of Power

The following summaries of the regional rules and regulations affecting our business focus on the West and Texas because these are the regions in which we have the most significant portfolios of assets. While we provide a brief overview of the primary regional rules and regulations affecting our power plants located in other regions of the country, we do not provide an in-depth discussion of these rules and regulations because our asset portfolio in those regions is not significant. All power plant and MW data is reported as of December 31, 2008.

West

Our subsidiaries own 26 natural gas-fired power plants excluding one under construction and one in advanced development with the capacity to generate a total of 6,521 MW in the WECC region, which extends from the Rocky Mountains westward. In addition, we own and operate 15 geothermal power plants located in northern California, capable of producing a total of 725 MW. The majority of these power plants are located in California, in the CAISO region; however, we also own power plants in Arizona, Colorado and Oregon.

CAISO is responsible for ensuring the safe and reliable operation of the transmission grid within California and providing open, nondiscriminatory transmission services. Pursuant to a FERC-approved tariff, CAISO has certain abilities to impose penalties on market participants for violations of its rules. CAISO maintains various markets for wholesale sales of power, differentiated by time and type of electrical service, into which our subsidiaries may sell power from time to time. These markets are subject to various controls, such as price caps and mitigation of bids when reference prices are exceeded. The controls and the markets themselves are subject to regulatory change at any time.

CAISO is preparing to implement MRTU, which was previously approved by FERC. MRTU is a comprehensive redesign of all CAISO operations currently slated to go into effect March 31, 2009. Under MRTU, the CAISO will run a new integrated day-ahead market for energy and ancillary services as well as a real-time market and an hour-ahead scheduling protocol. The energy market will change from a zonal to a nodal (locational) market. The primary features of a nodal market include a centralized, day-ahead market for energy, a nodal transmission congestion management model that results in locational marginal pricing at each generation location, financial congestion hedging instruments, a centralized day-ahead commitment process and an increase to the existing bid caps. Given the comprehensiveness of the market design, with features that may prove to be both positive and negative for energy sellers, we cannot predict at this time what impact MRTU will have on our business.

Our plants located outside of California either sell power into the markets administered by CAISO or sell power through bilateral transactions outside CAISO. Those transactions occurring outside CAISO are subject to FERC regulation and oversight, but they are not subject to CAISO rules and regulations.

Texas

Our subsidiaries own 12 natural gas-fired power plants in Texas with the capacity to generate a total of 7,487 MW, all of which are physically located in the ERCOT market. ERCOT is an ISO that manages approximately 85% of Texas' load and an electric grid covering about 75% of the state, overseeing transactions associated with Texas' competitive wholesale and retail power market. FERC does not regulate wholesale sales of power in ERCOT. The PUCT exercises regulatory jurisdiction over the rates and services of any electric utility conducting business within Texas. Our subsidiaries that own power plants in Texas have power generation company status at the PUCT, and are either EWGs or QFs and are exempt from PUCT rate regulation. ERCOT is largely a bilateral wholesale power market, which allows buyers and sellers to competitively negotiate contracts for energy, capacity and ancillary services. ERCOT meets its system needs by using ancillary service capacity and running a balancing energy service. ERCOT manages transmission congestion with zonal and intra-zonal type methods. ERCOT ensures resource adequacy through an energy-only model rather than the capacity-based resource adequacy model that is more common among RTOs or ISOs in the Eastern Interconnect. In ERCOT there is a market price cap for energy and capacity purchased by ERCOT. Under certain market conditions, the offer cap could be lower. Our subsidiaries are subject to the offer cap rules, but only for sales of energy and capacity services to ERCOT.

ERCOT's implementation of a nodal market structure was scheduled to have been implemented in late 2008. However, on May 20, 2008, ERCOT announced that it would delay implementation. The PUCT initiated an effort to refresh the original cost-benefit study analysis that had justified moving to a nodal design. Based on the refreshed analysis, ERCOT states that it intends to implement nodal design at the end of 2010. We anticipate a neutral business impact on us, but we are not able to rule out other impacts.

On July 17, 2008, the PUCT tentatively approved a transmission build plan to expand the delivery of wind-generated electricity from western Texas to service approximately 18,500 MW of planned wind generation. Wind generation tends to supply more power during off-peak hours and shoulder months, and is unpredictable. If completed as currently approved, the impact of the transmission upgrades and associated wind generation on our Texas segment is unknown, although it likely will increase the volatility of power prices.

North

New York and the New England regions are part of the NPCC NERC region, in which we have a total of six natural gas-fired power plants with the capacity to generate a total of 889 MW. Five of these power plants are located in New York. NYISO manages the transmission system in New York and operates the state's wholesale power markets. NYISO manages both day-ahead and real-time energy markets using a locationally based marginal pricing mechanism that pays each generator the nodal marginally accepted bid price for the energy it produces.

The remaining U.S.-based power plant in the NPCC is located in Maine. ISO NE is the RTO for Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont. ISO NE has broad authority over the day-to-day operation of the transmission system and operates a day-ahead and real-time wholesale energy market, a forward capacity market and ancillary services markets. ISO NE also provides for regional transmission planning.

We also have 50% joint venture interests in two power plants with the total capacity to generate 1,055 MW, located in the NPCC region in Ontario, Canada. The IESO operates the Province's wholesale power markets and directs the operation and ensures reliability of the IESO controlled grid. Hydro-One owns and operates the transmission system in Ontario, which is regulated by the Ontario Energy Board.

We have one operating power plant, with the capacity to generate 503 MW, located in PJM, which is located in the RFC NERC region. However, it is partially committed to load in MISO. PJM operates wholesale power markets, a locationally based capacity market, a forward capacity market and ancillary service markets. PJM also performs transmission planning for the region.

We have three natural gas-fired power plants with the capacity to generate a total of 1,430 MW operating within the MISO region. MISO manages competitive locationally based wholesale day-ahead and real-time energy markets. MISO's ancillary service markets went into effect on January 6, 2009. MISO currently manages an energy-only-based resource adequacy model but is finalizing a capacity-based resource adequacy model.

Southeast

We have one operating natural gas-fired power plant with the capacity to generate 1,134 MW located in SPP. SPP is an RTO approved by FERC that provides independent administration of the electric power grid. SPP manages an energy-only locationally based real-time wholesale energy market. This market provides both nominal load-following and transmission constraint relief. SPP stakeholders are considering the creation of a day-ahead market and ancillary service markets.

We have ten natural gas-fired power plants with the capacity to generate a total of 4,970 MW operating within the SERC and the FRCC NERC regions. Opportunities to negotiate bilateral, individual contracts and long-term transactions with investor owned utilities, municipalities and cooperatives exist within these footprints. In addition to entering into bilateral transactions, there is a limited opportunity to sell into the short-term market. In the Entergy sub-region, SPP has been designated as the ICT. In this capacity, the ICT provides oversight of the Entergy transmission system.

Other State Regulation of Power

State PUCs have historically had broad authority to regulate both the rates charged by, and the financial activities of, electric utilities operating in their states and to promulgate regulation for implementation of PURPA. Because all of our affiliates are either QFs or EWGs, none of our affiliates are currently subject to direct rate regulation by a state PUC. However, states may assert jurisdiction over the siting and construction of power generating facilities including QFs and EWGs and, with the exception of QFs, over the issuance of securities and the sale or other transfer of assets by these facilities. In California, for example, the CPUC was required by statute to adopt and enforce maintenance and operation standards for power plants "located in the state," including EWGs but excluding QFs, for the purpose of ensuring their reliable operation. As the owner and operator of power plants in California, our subsidiaries are subject to the power plant maintenance and operation standards and the general duty standards that are enforced by the CPUC.

Regulation of Transportation and Sale of Natural Gas

Because the majority of our power generating capacity is derived from natural gas-burning power plants, we are broadly impacted by federal regulation of natural gas transportation and sales. Furthermore, our two natural gas transportation pipelines in Texas are subject to dual jurisdiction by FERC and the Texas Railroad Commission. These pipelines are intrastate pipelines within the meaning of Section 2(16) of the NGPA. FERC regulates the rates charged by these pipelines for transportation services performed under Section 311 of the NGPA, and the Texas Railroad Commission regulates the rates and services provided by these pipelines as gas utilities in Texas. Additionally, under the NGA, the NGPA and the Outer Continental Shelf Lands Act, FERC is authorized to regulate pipeline, storage and LNG facility construction; the transportation of natural gas in interstate commerce; the abandonment of facilities; and the rates for services. FERC is also authorized under the NGA to regulate the sale of natural gas at wholesale. FERC also has the authority to regulate the quality of LNG deliveries into the pipeline system. Unless appropriate natural gas specifications are implemented, LNG supplies could impact in the future our plant operations and the ability to meet emission limits.

FERC has civil penalty authority for violations of the NGA and NGPA, as well as any rule or order issued thereunder. FERC's regulations specifically prohibit the manipulation of the natural gas markets by making it unlawful for any entity in connection with the purchase or sale of natural gas, or the purchase or sale of transportation service under FERC's jurisdiction, to engage in fraudulent or deceptive practices. Similar to its penalty authority under the FPA described above, FERC is authorized to assess a maximum civil penalty of $1 million per violation for each day that the violation continues. The NGA and NGPA also provide for the assessment of criminal fines and imprisonment time for violations.

CFTC Regulation of Power and Natural Gas

The CFTC has regulatory oversight of the futures markets, (including trading on NYMEX for energy), and licensed futures professionals (brokers, clearing members and large traders). In connection with its oversight of the futures markets and NYMEX, the CFTC regularly investigates market irregularities and potential manipulation of those markets. Recent laws also give the CFTC certain powers with respect to broker-type markets referred to as "exempt commercial markets" or ECMs, including the Intercontinental Exchange. The CFTC monitors activities in the OTC, ECM, and physical markets that may be undertaken for the purpose of influencing futures prices. With respect to ECMs, the CFTC exercises only light-handed regulation primarily related to price reporting and record retention. Thus, transactions executed on an ECM generally are not regulated directly by the CFTC. However, ECM transactions have come under the CFTC's scrutiny during investigations of fraud and manipulation in which the CFTC has broadly applied its statutory authority to punish persons who are alleged to have manipulated, or attempted to manipulate, the price of any commodity in interstate commerce or for future delivery. Moreover, Congress currently is considering legislation that would expand the regulatory authority of the CFTC. The CFTC has not investigated us for fraud or market manipulation in the past and we are not aware of any potential future CFTC actions.

Canadian Environmental, Health and Safety Regulations

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

EMPLOYEES

As of December 31, 2008, we employed 2,049 full-time employees, of whom 41 were represented by collective bargaining agreements. The collective bargaining agreements for those employees have expired but we continue to operate under their terms and are in active negotiations with our employees' collective bargaining representatives for new agreements. We have never experienced a work stoppage or strike.

Item 1A. *Risk Factors*

Economic and Financial Capital Market Conditions

A general economic downturn could result in a reduction in our revenue, or result in our customers, counterparties, vendors or other service providers failing to perform under their contracts with us.

To the extent that general economic downturns affect the markets in which we operate, demand for power and power prices may be reduced, which could reduce our revenues. In addition, challenges currently affecting the economy could cause our customers, counterparties, vendors and service providers to experience serious cash flow problems and, as a result, they may be unable to perform under existing contracts, or may significantly increase their prices or reduce their output or performance on future contracts. If the duration and severity of the general economic downturn results in a significant reduction in our expected revenues and operating cash flows over time, we could experience future impairments of our power plant assets as a result.

The soundness of financial institutions could adversely affect us.

We have exposure to many different financial institutions and counterparties including those under our Exit Credit Facility and other credit and financing arrangements as we routinely execute transactions in connection with our hedging and optimization activities, including brokers and dealers, commercial banks, investment banks and other institutions and industry participants. Many of these transactions expose us to credit risk in the event that any of our lenders or counterparties are unable to honor their commitments or otherwise defaults under a financing agreement. In an effort to minimize the risk that our counterparties would not be able to honor their commitments under our Exit Credit Facility and to reduce the risk that future availability of credit from other sources may be limited, we drew $725 million under our Exit Credit Facility revolving facility on October 2, 2008, and have invested the proceeds in money market funds, which are mainly invested in U.S. Treasury securities or other obligations issued or guaranteed by the U.S. government, its agencies or instrumentalities.

Inability to access the credit and capital markets could adversely affect us.

We and our subsidiaries rely on access to the credit and capital markets as a source of liquidity for the portion of our working capital requirements not provided by cash generated from our operations, and to finance our capital projects, including project financing for the construction of our power plants or expansions of existing facilities. If our available cash, including future cash flows from operations, is not sufficient to repay our debt coming due in the near term, we may need to access the capital and credit markets to refinance debt. Market disruptions such as those experienced in the U.S. and abroad in 2008 and early 2009, including substantial uncertainty surrounding particular lending institutions and counterparties with which we do business, unprecedented volatility in the markets where our outstanding securities trade, and general economic downturns in the areas where we do business, may increase our cost of borrowing or adversely affect our ability to access sources of liquidity upon which we rely to finance our operations, and to satisfy or refinance our obligations as they become due. These disruptions may continue throughout 2009 or longer. In addition, we believe these conditions have and may continue to have an adverse effect on the price of our common stock, which in turn may also reduce our ability to access capital or credit markets.

Our ability to manage our counterparty credit risk could adversely affect us.

Our counterparties may experience deteriorating credit. These conditions could cause counterparties in the natural gas and power markets, particularly in the power derivative markets that we rely on for our hedging activities, to withdraw from participation in those markets. If multiple parties withdraw from those markets, market liquidity may be threatened, which in turn could adversely impact our business. Additionally, these conditions may cause our counterparties to seek bankruptcy protection under Chapter 11 or liquidation under Chapter 7 of the Bankruptcy Code. Our credit risk may be exacerbated to the extent collateral held by us cannot be realized or is liquidated at prices not sufficient to recover the full amount of the derivative exposure due to us. There can be no assurance that any such losses or impairments to the carrying value of our financial assets would not materially and adversely affect our business or results of operations.

The U.S. government's proposed plan to address the financial crisis may not be effective to stabilize the financial markets or to increase the availability of credit.

In response to the financial crisis affecting the banking system and financial markets, and going concern threats to investment banks and other financial institutions causing disruptions in the credit and capital markets and a global economic downturn, the U.S. Congress and government have enacted legislation and proposed several additional economic stimulus programs for the purpose of stabilizing the financial markets and increasing the availability of credit. However, the capital markets have continued to experience extreme levels of volatility and the credit markets have not yet shown any significant increase in the availability of credit. There can be no assurance what the impact of these programs ultimately will have on the financial markets or the U.S. economy. If actions taken pursuant to legislation are not successful in stabilizing the economy, particularly the financial markets, and increasing the availability of credit, it could have a material adverse effect on our business, financial condition or results of operations, or the trading price of our common stock.

Capital Resources; Liquidity

We have substantial liquidity needs and could face liquidity pressure.

As of December 31, 2008, our consolidated debt outstanding was $10.5 billion, of which approximately $6.6 billion was outstanding under our Exit Credit Facility. In addition we had $556 million in letters of credit outstanding and our pro rata share of unconsolidated subsidiary debt was approximately $477 million. Although we have reduced our debt as a result of our reorganization, we could face liquidity challenges as we continue to have substantial debt and substantial liquidity needs in the operation of our business. Our ability to make payments on our indebtedness, and to fund planned capital expenditures and development efforts will depend on our ability to generate cash in the future from our operations and our ability to access the capital markets. This, to a certain extent, is dependent upon industry conditions, as well as general economic, financial, competitive, legislative, regulatory and other factors that are beyond our control, as discussed further under "— Economic and Financial Capital Market Conditions." Our borrowing capacity under our existing credit facilities remains limited. Although we are permitted to enter into new project financing credit facilities to fund our development and construction activities under certain circumstances, there can be no assurance that we will not face liquidity pressure in the future. See additional discussion regarding our capital resources and liquidity in Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations — Liquidity and Capital Resources."

Our substantial indebtedness could adversely impact our financial health and limit our operations.

Our level of indebtedness has important consequences, including:

- limiting our ability to borrow additional amounts for working capital, capital expenditures, debt service requirements, potential growth or other purposes;
- limiting our ability to use operating cash flows in other areas of our business because we must dedicate a substantial portion of these funds to service our debt;
- increasing our vulnerability to general adverse economic and industry conditions;
- limiting our ability to capitalize on business opportunities, and to react to competitive pressures and adverse changes in governmental regulation;
- limiting our ability or increasing the costs to refinance indebtedness or to repurchase equity issued by certain of our subsidiaries to third parties; and
- limiting our ability to enter into marketing, hedging and optimization transactions by reducing the number of counterparties with whom we can transact as well as the volume of those transactions.

Substantially all of our indebtedness contains floating rate interest provisions, which could adversely affect our financial health if interest rates were to rise significantly.

Substantially all of our indebtedness contains floating rate interest provisions, which we pay on a current basis. However, interest on unhedged obligations could rise to levels in excess of the cash available to us from operations. If we are unable to satisfy our obligations under our floating rate debt, particularly our Exit Credit Facility, it could result in defaults under our Exit Credit Facility and other debt instruments. We manage our interest rate risk through the use of derivative instruments, including interest rate swaps. See also Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations — Financial Market Risks — Interest Rate Risk."

We may be unable to obtain additional financing in the future.

Our ability to arrange financing (including any extension or refinancing) and the cost of the financing are dependent upon numerous factors. For example, because of our credit ratings, we may not be able to obtain any material amount of additional debt financing. In addition, the restrictions against additional borrowing in our Exit Credit Facility may limit additional indebtedness other than through refinancing outstanding debt, or through project financings where we are able to pledge the project assets as security. Other factors include:

- general economic and capital market conditions, including those described under "— Economic and Financial Capital Market Conditions";
- conditions in power markets;
- regulatory developments;
- credit availability from banks or other lenders for us and our industry peers;
- investor confidence in the industry and in us;

- the continued reliable operation of our current power plants; and
- provisions of tax, regulatory and securities laws that are conducive to raising capital.

While we have utilized non-recourse or lease financing when appropriate, market conditions and other factors may prevent us from completing similar financings in the future. It is possible that we may be unable to obtain the financing required to develop, construct, acquire or expand power plants on terms satisfactory to us. We have financed our existing power plants using a variety of leveraged financing structures, including senior secured and unsecured indebtedness, construction financing, project financing, term loans and lease obligations. In the event of a default under a financing agreement which we do not cure, the lenders or lessors would generally have rights to the power plant and any related assets. In the event of foreclosure after a default, we may not be able to retain any interest in the power plant or other collateral supporting such financing. In addition, any such default or foreclosure may trigger cross default provisions in our other financing agreements.

We must either repay or refinance our debt maturing in the near term.

Our current maturities of long-term debt as of December 31, 2008 were $716 million. While we believe that we will have sufficient cash on hand and expected future cash flows from our future operations available to repay our debt maturing in 2009, if we were to use cash to make those repayments it could adversely impact our liquidity, and require us to reduce capital and other expenditures and take other steps to enable us to conserve our remaining capital resources. During 2008 and continuing into 2009, there has been a significant contraction in the availability of capital, including for participants in the power sector, as the U.S. and global economies have experienced unprecedented economic disruptions stemming initially from turmoil in the sub-prime mortgage industry and spreading to affect virtually all aspects of the economy. It is likely that these conditions will continue during 2009, and it is possible that we may not be able to access the capital or credit markets to refinance our debt coming due in 2009 or the terms of financing available to us in the future may not be attractive, in which case we may be required to use cash to repay that debt. We cannot provide any assurance that our business will generate sufficient cash flows from operations or that future borrowings will be available to us in an amount sufficient to enable us to pay our indebtedness when due and to fund our other liquidity needs. We may need to refinance all or a portion of our indebtedness, on or before maturity. While we believe we will be successful in repaying or refinancing all of our debt on or before maturity, we cannot provide any assurance that we will be able to do so.

Our Exit Credit Facility imposes significant restrictions on us; any failure to comply with these restrictions could have a material adverse effect on our liquidity and our operations.

The restrictions under our Exit Credit Facility could adversely affect us by limiting our ability to plan for or react to market conditions or to meet our capital needs and could result in an event of default under the Exit Credit Facility. These restrictions require us to meet certain financial performance tests on a quarterly basis and limit or prohibit our ability, subject to certain exceptions to, among other things:

- incur additional indebtedness and use proceeds from the issuance of stock;
- make prepayments on or purchase our or our subsidiaries' indebtedness or equity instruments in whole or in part;
- pay dividends and other distributions with respect to our stock, or repurchase our stock or make other restricted payments;
- use money borrowed under the Exit Credit Facility for non-guarantors (including foreign subsidiaries);

- make certain investments;
- create or incur liens to secure debt;
- consolidate or merge with another entity, or allow one of our subsidiaries to do so;
- lease, transfer or sell assets and use proceeds of permitted asset leases, transfers or sales;
- limit dividends or other distributions from certain subsidiaries up to us;
- make capital expenditures beyond specified limits;
- engage in certain business activities; and
- acquire power plants or other businesses.

The Exit Credit Facility contains events of default customary for financings of this type, including a cross default to debt other than non-recourse project financing debt, a cross-acceleration to non-recourse project financing debt and certain change of control events. If we fail to comply with the covenants in the Exit Credit Facility and are unable to obtain a waiver or amendment, or a default exists and is continuing under the Exit Credit Facility, the lenders could give notice and declare outstanding borrowings and other obligations under the Exit Credit Facility immediately due and payable.

Our ability to comply with these covenants may be affected by events beyond our control, and any material deviations from our forecasts could require us to seek waivers or amendments of covenants or alternative sources of financing or to reduce expenditures. We may not be able to obtain such waivers, amendments or alternative financing, or if obtainable, it could be on terms that are not acceptable to us. If we are unable to comply with the terms of the Exit Credit Facility, or if we fail to generate sufficient cash flows from operations, or if it became necessary to obtain such waivers, amendments or alternative financing, it could adversely impact our business, results of operations and financial condition.

Our credit status is below investment grade, which may restrict our operations, increase our liquidity requirements and restrict financing opportunities.

Our corporate and debt credit ratings are below investment grade. There is no assurance that our credit ratings will improve in the future, which may restrict the financing opportunities available to us or may increase the cost of any available financing. Our current credit rating has resulted in the requirement that we provide additional collateral in the form of letters of credit or cash for credit support obligations, and has had certain adverse impacts on our subsidiaries' and our financial position and results of operations.

Certain of our obligations are required to be secured by letters of credit or cash, which increase our costs; if we are unable to provide such security it may restrict our ability to conduct our business.

Companies using derivatives, which include many commodity contracts, are subject to the inherent risks of such transactions. Consequently, many companies, including us, may be required to post cash collateral for certain commodity transactions; and, the level of collateral will increase as a company increases its hedging activities. We use margin deposits, prepayments and letters of credit as credit support for commodity procurement and risk management activities. Future cash collateral 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. Certain of our financing arrangements for our power plants have required us to post letters of credit which are at risk of being drawn down in the event we, or the applicable subsidiary, default on our obligations.

These letter of credit and cash collateral requirements increase our cost of doing business and could have an adverse impact on our overall liquidity, particularly if there was a call for a large amount of additional cash or letter of credit collateral due to an unexpectedly large movement in the market price of a commodity. As of December 31, 2008, we had $556 million in letters of credit outstanding under our Exit Credit Facility and other facilities; with $16 million remaining available for borrowing or for letter of credit support under the Exit Credit Facility, following our October 2008 borrowing of $725 million under the Exit Credit Facility revolving facility. We entered into two financing agreements in 2008 to provide for increased liquidity in periods of increasing natural gas prices. As of December 31, 2008, we had $100 million in debt outstanding under our Commodity Collateral Revolver with an additional $200 million remaining available for advances or letters of credit under certain reference transactions to collateralize obligations to counterparties under eligible commodity hedge agreements, and we had $50 million in letters of credit outstanding under the Knock-in Facility with an additional $150 million in availability contingent upon natural gas prices exceeding certain thresholds. In addition, we have ratably secured our obligations under certain of our power and natural gas agreements that qualify as eligible commodity hedge agreements under our Exit Credit Facility with the assets currently subject to liens under the Exit Credit Facility.

We may not have sufficient liquidity to hedge market risks effectively.

We are exposed to market risks through our sale of power, capacity and related products and the purchase and sale of fuel, transmission services and emission allowances. These market risks include, among other risks, volatility arising from location and timing differences that may be associated with buying and transporting fuel, converting fuel into power and delivering the power to a buyer.

We undertake these activities through agreements with various counterparties, many of which require us to provide guarantees, offset or netting arrangements, letters of credit, a second lien on assets and/or cash collateral to protect the counterparties against the risk of our default or insolvency. The amount of such credit support that must be provided typically is based on the difference between the price of the commodity in a given contract and the market price of the commodity. Significant movements in market prices can result in our being required to provide cash collateral and letters of credit in very large amounts. The effectiveness of our strategy may be dependent on the amount of collateral available to enter into or maintain these contracts, and liquidity requirements may be greater than we anticipate or will be able to meet. Without a sufficient amount of working capital to post as collateral in support of performance guarantees or as a cash margin, we may not be able to manage price volatility effectively or to implement our strategy. An increase in the amount of letters of credit or cash collateral required to be provided to our counterparties may negatively affect our liquidity and financial condition.

Further, if any of our power plants experience unplanned outages, we may be required to procure replacement power at spot market prices in order to fulfill contractual commitments. Without adequate liquidity to meet margin and collateral requirements, we may be exposed to significant losses, may miss significant opportunities and may have increased exposure to the volatility of spot markets.

Our ability to receive future cash flows generated from the operation of our subsidiaries may be limited.

Almost all of our operations are conducted through our subsidiaries and other affiliates. As a result, we depend almost entirely upon their earnings and cash flows to service our indebtedness, including our Exit Credit Facility, finance our ongoing operations, and fund our restructuring costs. Certain of our project debt and other agreements restrict our ability to receive dividends and other distributions from our subsidiaries. Some of these limitations are subject to a number of significant exceptions (including exceptions permitting such restrictions in connection with certain subsidiary financings). Accordingly, the financing agreements of certain of our subsidiaries and other affiliates generally restrict their ability to pay dividends, make distributions, or otherwise transfer funds to us prior to the payment of their other obligations, including their outstanding debt, operating expenses, lease payments and reserves, or during the existence of a default.

We may utilize project financing, preferred equity and other types of subsidiary financing transactions when appropriate in the future.

Our ability and the ability of our subsidiaries to incur additional indebtedness are limited in some cases by existing indentures, debt instruments or other agreements. Our subsidiaries may incur additional construction/project financing indebtedness, issue preferred equity to finance the acquisition and development of new power plants and engage in certain types of non-recourse financings to the extent permitted by existing agreements, and may continue to do so in order to fund our ongoing operations. Any such newly incurred subsidiary debt, and certain types of preferred equity, would be added to our current consolidated debt levels and could intensify the risks associated with our already substantial leverage. Any such newly incurred subsidiary preferred equity would likely be structurally senior to our debt and could also intensify the risks associated with our already substantial leverage.

Our Exit Credit Facility and other parent-company debt is effectively subordinated to certain project indebtedness.

Certain of our subsidiaries and other affiliates are separate and distinct legal entities and, except in limited circumstances, have no obligation to pay any amounts due with respect to our indebtedness or indebtedness of other subsidiaries or affiliates, and do not guarantee the payment of interest on or principal of such indebtedness. In the event of our bankruptcy, liquidation or reorganization (or the bankruptcy, liquidation or reorganization of a subsidiary or affiliate), such subsidiaries' or other affiliates' creditors, including trade creditors and holders of debt issued by such subsidiaries or affiliates, will generally be entitled to payment of their claims from the assets of those subsidiaries or affiliates before any assets are made available for distribution to us or the holders of our indebtedness. As a result, holders of our indebtedness will be effectively subordinated to all present and future debts and other liabilities (including trade payables) of certain of our subsidiaries. As of December 31, 2008, our subsidiaries had approximately $1.5 billion of secured construction/project financing and $1.1 billion in debt from our CCFC subsidiary and preferred interests, which are effectively senior to our Exit Credit Facility. We may incur additional project financing indebtedness in the future, which will be effectively senior to our other secured and unsecured debt.

Operations

Our financial results may be volatile and may not reflect historical trends.

After our emergence from Chapter 11, the amounts reported in our subsequent Consolidated Financial Statements may materially change relative to our historical Consolidated Financial Statements, including as a result of our restructuring activities, the implementation of our Plan of Reorganization and the continued execution of our business strategies.

Our results are subject to quarterly and seasonal fluctuations.

Our quarterly operating results have fluctuated in the past and may continue to do so in the future as a result of a number of factors (see Note 18 of the Notes to Consolidated Financial Statements for our 2008 and 2007 quarterly operating results), including:

- seasonal variations in power and natural gas prices and capacity payments;
- seasonal fluctuations in weather, in particular unseasonable weather conditions;
- production levels of hydroelectric power in the West;
- variations in levels of production, including from forced outages;

- availability of emissions credits;
- natural disasters, wars, sabotage, terrorist acts, earthquakes, hurricanes and other catastrophic events; and
- the completion of development and construction projects.

In particular, a disproportionate amount of our total revenue has historically been realized during the third fiscal quarter and we expect this trend to continue in the future as demand for power in our markets peaks in our third fiscal quarter. If our total revenue were below seasonal expectations during that quarter, by reason of power plant operational performance issues, cool summers, or other factors, it could have a disproportionate effect on our annual operating results.

Accounting for our hedging activities may increase the volatility in our quarterly and annual financial results.

We engage in commodity-related marketing and price-risk management activities in order to financially hedge our exposure to market risk with respect to power sales from our power plants, fuel utilized by those assets and emission allowances. We generally attempt to balance our fixed-price physical and financial purchases, and sales commitments in terms of contract volumes and the timing of performance and delivery obligations through the use of financial and physical derivative contracts. These derivatives are accounted for in accordance with SFAS No. 133, which requires us to record all derivatives on the balance sheet at fair value unless they qualify for the normal purchase normal sale exception. Changes in the fair value resulting from fluctuations in the underlying commodity prices are immediately recognized in earnings, unless the derivative qualifies for cash flow hedge accounting treatment. Sudden commodity price movements could create financial losses. Whether a derivative qualifies for cash flow hedge accounting treatment depends upon it meeting specific criteria used to determine if the cash flow hedge is and will remain effective for the term of the derivative. Economic hedges will not necessarily qualify for cash flow hedge accounting treatment. As a result, we may be unable to accurately predict the impact that our risk management decisions may have on our quarterly and annual operating results.

The use of hedging agreements could result in financial losses.

We typically enter into hedging agreements, including contracts to purchase or sell commodities at future dates and at fixed prices, in order to manage our commodity price risks. These activities, although intended to mitigate price volatility, expose us to other risks. When we sell power forward, we give up the opportunity to sell power at higher prices in the future, which not only may result in lost opportunity costs but may also require us to post significant amounts of cash collateral or other credit support to our counterparties. Further, if the values of the financial contracts change in a manner that we do not anticipate, or if a counterparty fails to perform under a contract, it could harm our business, operating results or financial position.

We do not typically hedge the entire exposure of our operations against commodity price volatility. To the extent we do not hedge against commodity price volatility, our results of operations and financial position may be improved or diminished based upon movement in commodity prices.

We may be subject to claims that were not discharged in the Chapter 11 cases, which could have a material adverse effect on our results of operations and profitability.

Although the majority of the material claims against us that arose prior to the Petition Date were resolved during our Chapter 11 cases, certain of such actions, as well as actions instituted during the pendency of our Chapter 11 cases, have not been resolved, and additional actions could be filed against us in the future. In general, all claims that arose prior to the Petition Date and before confirmation of the Plan of Reorganization were discharged in accordance with the Bankruptcy Code and the terms of the Plan of Reorganization; however, there are certain exceptions. Circumstances in which claims and other obligations, that arose prior to the Petition Date, were not discharged primarily relate to certain actions by governmental units under police power authority or where we have agreed to preserve a claimant's claims or a claimant has received court approval to proceed with their claim, as well as, potentially, instances where a claimant had inadequate notice of the Chapter 11 filing. The ultimate resolution of such claims and other obligations may have a material adverse effect on our results of operations and profitability. Additionally, despite our emergence from Chapter 11 on January 31, 2008, several significant matters remain unresolved in connection with our reorganization, including an appeal from a shareholder seeking reconsideration of the Confirmation Order. Unfavorable resolution of these matters could have a material adverse effect on our results of operations and profitability.

Revenue may be reduced significantly upon expiration or termination of our PPAs.

Some of the power we generate from our existing portfolio is sold under long-term PPAs that expire at various times. We also sell power under short- to intermediate-term (one day to five years) PPAs. Our uncontracted capacity is generally sold on the spot market at current market prices. When the terms of each of our various PPAs expire, it is possible that the price paid to us for the generation of power under subsequent arrangements or on the spot market may be significantly less than the price that had been paid to us under the PPA. In addition, power plants without long-term PPAs for some or all of their generating capacity and output are exposed to market fluctuations. Without the benefit of long-term PPAs, we may not be able to sell any or all of the power generated by these power plants at commercially attractive rates and these power plants may not be able to operate profitably.

Certain of our PPAs have values in excess of current market prices (measured over the next five years). The aggregate value of these PPAs is approximately $2.5 billion at December 31, 2008. Values for our long-term commodity contracts are calculated using discounted cash flows derived as the difference between contractually based cash flows and the cash flows to buy or sell similar amounts of the commodity on market terms. Inherent in these valuations are significant assumptions regarding future prices, correlations and volatilities, as applicable. The aggregate value of such contracts could decrease in response to changes in the market. We are at risk of loss in margins to the extent that these contracts expire or are terminated and we are unable to replace them on comparable terms. Approximately 63% of the calculated value of these PPAs will expire over the next three years. Additionally, our PPAs contain termination provisions standard to contracts in our industry such as negligence, performance default or prolonged events of force majeure.

In certain situations, our PPAs and other contractual arrangements, including construction agreements, commodity contracts, maintenance agreements and other arrangements, may be terminated by the counterparty and/or may allow the counterparty to seek liquidated damages.

The situations that could allow a counterparty to terminate the contract and/or seek liquidated damages include:

- the cessation or abandonment of the development, construction, maintenance or operation of a power plant;
- failure of a power plant to achieve construction milestones or commercial operation by agreed-upon deadlines;
- failure of a power plant to achieve certain output or efficiency minimums;
- our failure to make any of the payments owed to the counterparty or to establish, maintain, restore, extend the term of, or increase any required collateral;
- failure of a power plant to obtain material permits and regulatory approvals by agreed-upon deadlines;

- a material breach of a representation or warranty or our failure to observe, comply with or perform any other material obligation under the contract; or

- events of liquidation, dissolution, insolvency or bankruptcy.

We may be unable to obtain an adequate supply of natural gas in the future at prices acceptable to us.

We obtain substantially all of our physical natural gas supply from third parties pursuant to arrangements that vary in term, pricing structure, firmness and delivery flexibility. Our physical natural gas supply arrangements must be coordinated with transportation agreements, balancing agreements, storage services, financial hedging transactions and other contracts so that the natural gas is delivered to our power plants at the times, in the quantities and otherwise in a manner that meets the needs of our generation portfolio and our customers. We must also comply with laws and regulations governing gas transportation.

While adequate supplies of natural gas are currently available to us at prices we believe are reasonable for each of our power plants, we are exposed to increases in the price of natural gas and it is possible that sufficient supplies to operate our portfolio profitably may not continue to be available to us. In addition, we face risks with regard to the delivery to and the use of natural gas by our power plants including the following:

- transportation may be unavailable if pipeline infrastructure is damaged or disabled;

- pipeline tariff changes may adversely affect our ability to or cost to deliver natural gas supply;

- third-party suppliers may default on natural gas supply obligations and we may be unable to replace supplies currently under contract;

- market liquidity for physical natural gas or availability of natural gas services (e.g. storage) may be insufficient or available only at prices that are not acceptable to us;

- natural gas quality variation may adversely affect our plant operations; and

- our natural gas operations capability may be compromised due to various events such as natural disaster, loss of key personnel or loss of critical infrastructure.

We rely on power transmission and natural gas distribution facilities owned and operated by other companies.

We depend on facilities and assets that we do not own or control for the transmission to our customers of the power produced in our power plants and the distribution of natural gas fuel to our power plants. If these transmission and distribution systems are disrupted or capacity on those systems is inadequate, our ability to sell and deliver power products or obtain fuel may be hindered. ISOs that oversee transmission systems in regional power markets have imposed price limitations and other mechanisms to address volatility in their power markets. Existing congestion as well as expansion of transmission systems could affect our performance.

Our revenues and results of operations depend on market rules, regulation and other forces beyond our control.

Our revenues and results of operations are influenced by factors that are beyond our control, including:

- rate caps, price limitations and bidding rules imposed by ISOs, RTOs and other market regulators that may impair our ability to recover our costs and limit our return on our capital investments; and

- some of our competitors' (mainly utilities) entitlement-guaranteed rates of return on their capital investments, which returns may in some instances exceed market returns, may impact our ability to sell our power at economical rates.

Our power generating operations performance may be below expected levels of output or efficiency.

The operation of power plants involves risks, including the breakdown or failure of power generation equipment, transmission lines, pipelines or other equipment or processes, performance below expected levels of output or efficiency and risks related to the creditworthiness of our contract counterparties and the creditworthiness of our counterparties' customers or other parties (such as steam hosts) with whom our counterparties have contracted. From time to time our power plants have experienced equipment breakdowns or failures.

In addition, a breakdown or failure may prevent the affected power plant from performing under any applicable PPAs, commodity contracts or other contractual arrangements. Such failure may allow a counterparty to terminate an agreement and/or seek liquidated damages. Although insurance is maintained to partially protect against operating risks, the proceeds of insurance may not be adequate to cover lost revenues or increased expenses. As a result, we could be unable to service principal and interest payments under, or may otherwise breach, our financing obligations, particularly with respect to the affected power plant, which could result in losing our interest in the affected power plant or, possibly, one or more other power plants.

Our power project development activities may not be successful.

The development of power plants is subject to substantial risks. In connection with the development of a power plant, we must generally obtain:

- necessary power generation equipment;
- governmental permits and approvals including environmental permits and approvals;
- fuel supply and transportation agreements;
- sufficient equity capital and debt financing;
- power transmission agreements;
- water supply and wastewater discharge agreements or permits; and
- site agreements and construction contracts.

To the extent that our development activities continue or expand, we may be unsuccessful in developing power plants on a timely and profitable basis. Although we may attempt to minimize the financial risks in the development of a project by securing a favorable PPA and arranging adequate financing prior to the commencement of construction, the development of a power project may require us to expend significant cash sums for preliminary engineering, permitting, legal and other expenses before we can determine whether a project is feasible, economically attractive or financeable. If we are unable to complete the development of a power plant, we might not be able to recover our investment in the project and may be required to recognize additional impairments. The process for obtaining governmental permits and approvals is complicated and lengthy, often taking more than one year, and is subject to significant uncertainties.

Our geothermal power reserves may be inadequate for our operations.

In connection with each geothermal power plant, we estimate the productivity of the geothermal resource and the expected decline in productivity. The productivity of a geothermal resource may decline more than anticipated, resulting in insufficient reserves being available for sustained generation of the power capacity desired. In addition, we may not be able to successfully manage the development and operation of our geothermal reservoirs or accurately estimate the quantity or productivity of our steam reserves. An incorrect estimate or inability to manage our geothermal reserves, or a decline in productivity could adversely affect our results of operations or financial condition. In addition, the development and operation of geothermal power resources are subject to substantial risks and uncertainties. The successful exploitation of a geothermal power resource ultimately depends upon many factors including the following:

- the heat content of the extractable steam or fluids;
- the geology of the reservoir;
- the total amount of recoverable reserves;
- operating expenses relating to the extraction of steam or fluids;
- price levels relating to the extraction of steam, fluids or power generated; and
- capital expenditure requirements relating primarily to the drilling of new wells.

Natural disasters could damage our projects or our corporate offices.

Certain areas where we operate and are developing many of our geothermal and gas-fired projects, particularly in the West, are subject to frequent low-level seismic disturbances. More significant seismic disturbances are possible. In addition, other areas in which we operate, particularly in Texas and the Southeast, experience tornados and hurricanes. Similarly, operations at our corporate offices in Houston, Texas could be substantially affected by a hurricane. Our existing power plants are built to withstand relatively significant levels of seismic and other disturbances, and we believe we maintain adequate insurance protection. However, earthquake, property damage or business interruption insurance may be inadequate to cover all potential losses sustained in the event of serious damages or disturbances to our power plants or our operations due to natural disasters.

We depend on our management and employees.

Our success is largely dependent on the skills, experience and efforts of our people. While we believe that we have excellent depth throughout all levels of management and in all key skill levels of our employees, the loss of the services of one or more members of our senior management or of numerous employees with critical skills could have a negative effect on our business, financial condition and results of operations and future growth if we were unable to replace them.

We depend on computer and telecommunications systems we do not own or control.

We have entered into agreements with third parties for hardware, software, telecommunications, and database services in connection with the operation of our power plants. In addition, we have developed proprietary software systems, management techniques and other information technologies incorporating software licensed from third parties. Any interruptions to our arrangements with third parties, to our computing and communications infrastructure, or our information systems could significantly disrupt our business operations.

Competition could adversely affect our performance.

The power generation industry is characterized by intense competition, and we encounter competition from utilities, industrial companies, marketing and trading companies, and other IPPs. In addition, many states are implementing or considering regulatory initiatives designed to increase competition in the domestic power industry. This competition has put pressure on power utilities to lower their costs, including the cost of purchased power, and increasing competition in the supply of power in the future could increase this pressure. In addition, construction during the last decade has created excess power supply and higher reserve margins, which has led to tight liquidity in the power trading markets, putting downward pressure on prices.

Our financial performance may be impacted by price fluctuations in the wholesale power markets and other market factors that are beyond our control.

Market prices for power, generation capacity and ancillary services tend to fluctuate substantially. Unlike most other commodities, power can only be stored on a very limited basis and generally must be produced concurrently with its use. As a result, power prices are subject to significant volatility due to supply and demand imbalances, especially in the day-ahead and spot markets. Long- and short-term power prices may also fluctuate substantially due to other factors outside of our control, including:

- increases and decreases in generation capacity in our markets, including the addition of new supplies of power as a result of the development of new generation plants, expansion of existing plants or additional transmission capacity;
- changes in power transmission or fuel transportation capacity constraints or inefficiencies;
- power supply disruptions, including plant outages and transmission disruptions;
- Heat Rate risk;
- weather conditions;
- changes in the demand for power or in patterns of power usage, including the potential development of demand-side management tools and practices;
- development of new fuels and new technologies for the production of power;
- regulations and actions of the ISOs; and,
- federal and state power market and environmental regulation and legislation including mandating RPS or creating financial incentives each resulting in new renewable energy generation capacity creating oversupply.

These factors have caused our operating results to fluctuate in the past and will continue to cause them to do so in the future.

Governmental Regulation

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

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

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

In 2008, there were several bills introduced in the U.S. Congress concerning climate change. We believe the current federal administration will intensify these efforts. We expect proposed legislation will take the form of a cap-and-trade program where generators receive allowances and/or purchase allowances to emit CO_2 and other GHGs. It is possible the legislation may take other forms, such as a carbon tax on each unit of CO_2 or GHG emitted in excess of mandated limits. In general, we expect GHG regulations will be favorable to us due to the efficiency of our natural gas fleet. Our combined-cycle, natural gas-fired power plants emit less than half the CO_2 per unit of power generated compared to a traditional coal-fired unit. In addition, our Geysers Assets are exempted from regulation under the currently proposed cap-and-trade programs. As a result of requirements for GHG emissions, we could be required to purchase allowances or offsets to emit GHGs or other regulated pollutants or to pay taxes on such emissions. Although the ultimate legislation and regulations that result from these activities could have a material impact on our business, we believe we will face a lower compliance burden than most competitors due to the relatively low GHG emission rates of our fleet.

Under a Cap-and-trade or carbon tax approach to reducing GHG emissions, companies that sell power and steam under existing long-term contracts may not be able to recover compliance costs or carbon taxes. Many long-term contracts that were executed before GHG emissions regulations were anticipated do not contain applicable "change in law" provisions that would enable the generators to pass such costs or taxes to the customer. We have certain power and steam sales contracts that may not allow such costs or taxes to be recovered from our customers.

Existing and proposed federal and state RPS and energy efficiency, as well as economic support for renewable sources of power under the U.S economic stimulus legislation could adversely impact our operations.

Federal policy makers have been considering imposing a national RPS on retail power providers. California already has an RPS in effect and is currently considering new and higher RPS. A number of additional states, including Maine, Minnesota, New York, Texas and Wisconsin, have an array of different RPS in place. Existing state-specific RPS requirements may change due to regulatory and/or legislative initiatives, and other states may consider implementing enforceable RPS in the future. A national RPS or more robust RPS in states in which we are active, coupled with economic incentives provided under the federal stimulus package, would likely initially drive up the number of wind and solar resources, increasing power supply to various markets which could negatively impact the dispatch of our natural gas assets, primarily in Texas and California.

Similarly, federal legislators are considering national energy efficiency initiatives. Several states already have energy efficiency initiatives in place while others are considering imposing them. Improved energy efficiency when mandated by law or promoted by government sponsored incentives can decrease demand for power which could negatively impact the dispatch of our gas assets, primarily in Texas and California.

We are subject to complex governmental regulation which could adversely affect our operations.

Generally, in the U.S., we are subject to regulation by FERC regarding the terms and conditions of wholesale service and the sale and transportation of natural gas, as well as by state agencies regarding physical aspects of the power plants. The majority of our generation is sold at market prices under the market-based rate authority granted by the FERC. If certain conditions are not met, FERC has the authority to withhold or rescind market-based rate authority and require sales to be made based on cost-of-service rates. A loss of our market-based rate authority could have a materially negative impact on our generation business. FERC could also impose fines or other restrictions or requirements on us under certain circumstances.

The construction and operation of power plants require numerous permits, approvals and certificates from appropriate foreign, federal, state and local governmental agencies, as well as compliance with federal, state and local legislation and regulations. We must also comply with numerous environmental laws and regulations of federal, state and local authorities and obtain numerous governmental permits and approvals to operate our power plants. Should we fail to comply with any environmental requirements that apply to power plant construction or operations, we could be subject to administrative, civil and/or criminal liability and fines, and regulatory agencies could take other actions to curtail our operations. We may be unable to obtain all necessary licenses, permits, approvals and certificates for proposed projects, and completed power plants may not comply with all applicable permit conditions, statutes or regulations. In addition, regulatory compliance for the construction and operation of our power plants can be a costly and time-consuming process. Intricate and changing environmental and other regulatory requirements may necessitate substantial expenditures to obtain and maintain permits. If a project is unable to function as planned due to changing requirements, loss of required permits or regulatory status or local opposition, it may create expensive delays, extended periods of non-operation or significant loss of value in a project.

Furthermore, certain environmental laws impose strict, joint and several liability for costs required to clean up and restore sites where hazardous substances have been disposed or otherwise released. We are generally responsible for all liabilities associated with the environmental condition of our power plants, including any soil or groundwater contamination that may be present, regardless of when the liabilities arose and whether the liabilities are known or unknown, or arose from the activities of predecessors or third parties.

If we were deemed to have market power in certain markets as a result of the ownership of our stock by certain significant shareholders, we could lose FERC authorization to sell power at wholesale at market-based rates in such markets or be required to engage in mitigation in those markets.

Certain of our significant shareholder groups own power generating assets, or own significant equity interests in entities with power generating assets, in markets where we currently own power plants. FERC has ruled that we do not have market power as a consequence of their ownership of our common stock. However, we could be determined to have market power if these existing significant shareholders acquire additional significant ownership or equity interest in other entities with power generating assets in the same markets where we generate and sell power.

If FERC makes the determination that we have market power, FERC could, among other things, revoke market-based rate authority for the affected market-based companies or order them to mitigate that market power. If market-based rate authority were revoked for any of our market-based rate companies, those companies would be required to make wholesale sales of power based on cost-of-service rates, which could negatively impact their revenues. If we are required to mitigate market power, we could be required to sell certain power plants in regions where we are determined to have market power. A loss of our market-based rate authority or required sales of power plants, particularly if it affected several of our power plants or was in a significant market such as California, could have a material negative impact on our business, results of operations or financial condition.

Risks Relating to Our Common Stock

The market pricing of our common stock has been volatile.

Our common stock began trading on the NYSE on a "when issued" basis on January 16, 2008, and began "regular way" trading on the NYSE on February 7, 2008. The market price for our common stock has been volatile in the past, and the price of our common stock could fluctuate substantially in the future. Factors that could affect the price of our common stock in the future include general conditions in our industry, in the power markets in which we participate and in the world, including environmental and economic developments, over which we have no control, as well as developments specific to us, including fluctuations in our results of operations, our ability to comply with the covenants under our Exit Credit Facility and other debt instruments, our ability to execute our business plan, and other matters discussed in these risk factors. As noted above, the market price of our common stock may be adversely affected due to the concentration of ownership of our shares in a small number of holders, particularly if certain of these large shareholders sought to sell all or a large portion of their shares in a short period of time. Moreover, in addition to the approximately 427 million shares of reorganized Calpine Corporation common stock that have been distributed to creditors pursuant to the Plan of Reorganization, approximately 58 million shares have been reserved for distribution upon the resolution of disputed claims and pending resolution of certain inter-creditor matters; the distribution of these additional shares could have a dilutive effect on our current holders and may adversely affect the market price of our common stock. Accordingly, trading in our securities is highly speculative and poses substantial risks.

Our principal shareholders own a significant amount of our common stock, giving them influence over corporate transactions and other matters.

Three holders (or related groups of holders) of our common stock have made filings with the SEC reporting beneficial ownership, directly or indirectly, individually or as members of a group, of 10% or more of the shares of our common stock. These shareholders, who together beneficially own approximately 63% of our common stock, may be able to exercise substantial influence over all matters requiring shareholder approval, including the election of directors and approval of significant corporate action, such as mergers and other business combination transactions. If two or more of these shareholders (or groups of shareholders) vote their shares in the same manner, their combined stock ownership may effectively give them the power to elect our entire Board of Directors and control our management, operations and affairs. Currently, two members of our Board of Directors, including the Chairman of our Board, are affiliated, directly or indirectly, with SPO Advisory Corp., one of these shareholders.

Circumstances may occur in which the interests of these shareholders could be in conflict with the interests of other shareholders. This concentration of ownership may also have the effect of delaying or preventing a change in control over us unless it is supported by these shareholders. Accordingly, your ability to influence us through voting your shares may be limited or the market price of our common stock may be adversely affected. Additionally, we have filed a registration statement on Form S-3 registering the resale of the common stock held by certain members of two of the three groups of these shareholders, which will permit them to sell a large portion of their shares of common stock without being subject to the "trickle out" or other restrictions of Rule 144 under the Securities Act. If these shareholders sought to sell all of their registered shares within a short period of time, it could adversely affect the market price of our common stock. Additionally, if two of the three groups of these shareholders agree to sell their shares included on the registration statement on Form S-3 to one shareholder, it could concentrate a significant share of our ownership with one shareholder.

Transfers of our equity, or issuances of equity in connection with our reorganization, may impair our ability to utilize our federal income tax NOL carryforwards in the future.

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

To prevent the risk of loss of our ability to utilize our tax NOL carryforwards, our amended and restated certificate of incorporation permits our Board of Directors to meet to determine whether to impose certain transfer restrictions on our common stock in the following circumstances: if, prior to February 1, 2013, our

Market Capitalization declines by at least 35% from our Emergence Date Market Capitalization of approximately $8.6 billion (calculated pursuant to our amended and restated certificate of incorporation) and at least 25 percentage points of shift in ownership has occurred with respect to our equity for purposes of Section 382 of the IRC. During 2008, and through the filing of this Report, we have experienced declines in our stock price of more than 50% from our Emergence Date Market Capitalization. As of the filing of this Report, our shift in ownership is approximately 10%.

We have filed a registration statement on Form S-3 registering the resale of the common stock held by two holders (or related groups of holders) of our common stock that collectively own approximately 47% of our common stock, which will permit them to sell a large portion of their shares of common stock without being subject to the "trickle out" or other restrictions of Rule 144 under the Securities Act. If these shareholders sought to sell all of their registered shares within a short period of time, pursuant to the Form S-3 or otherwise, it would result in a shift in ownership of greater than 25 percentage points and our Board of Directors could elect to impose certain trading restrictions on our common stock as described above.

These restrictions are not currently operative but could become operative in the future if the foregoing events occur and our Board of Directors elect to impose them. There can be no assurance that the circumstances will not be met in the future, or in the event that they are met, that our Board of Directors would choose to impose these restrictions or that, if imposed, such restrictions would prevent an ownership change from occurring.

Item 1B. ***Unresolved Staff Comments***

None.

Item 2. ***Properties***

Our principal executive offices are located in Houston, Texas and San Jose, California. These facilities are leased until 2013 and 2009, respectively. We also lease offices for regional operations in San Jose, Folsom, Sacramento, and Pleasanton, California; Lincolnshire, Illinois; La Porte, Texas; and Washington, D.C. Our San Jose and Pleasanton, California as well as our Lincolnshire, Illinois office leases expire in 2009. Effective April 1, 2009, we intend to make Houston our sole headquarters and we intend to consolidate our San Jose and Pleasanton personnel into one new office in Dublin, California.

We either lease or own the land upon which our power plants are built. We believe that our properties are adequate for our current operations. A description of our power plants is included under Item 1. "Business — Description of Our Power Plants."

Item 3. ***Legal Proceedings***

See Note 16 of the Notes to Consolidated Financial Statements for a description of our legal proceedings.

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

None.

PART II

Item 5. *Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities*

Market Information and Stockholder Matters

Public trading of our previously outstanding common stock originally commenced on September 20, 1996, on the NYSE under the symbol "CPN." Prior to that, there was no public market for our common stock. On December 2, 2005, the NYSE notified us that it was suspending trading in our common stock prior to the opening of the market on December 6, 2005, and the SEC approved the application of the NYSE to delist our common stock effective March 15, 2006. From December 6, 2005, to January 31, 2008, our common stock traded in the OTC market as reported on the Pink Sheets under the symbol "CPNLQ.PK." On January 31, 2008, pursuant to the Plan of Reorganization, our previously outstanding common stock was canceled and we authorized and began issuance of 485 million shares of reorganized Calpine Corporation common stock to settle unsecured claims pursuant to the Plan of Reorganization. On January 16, 2008, the shares of reorganized Calpine Corporation common stock were admitted to listing on the NYSE and began "when issued" trading under the symbol "CPN-WI." The reorganized Calpine Corporation common stock began "regular way" trading on the NYSE under the symbol "CPN" on February 7, 2008.

The following table sets forth the high and low bid prices for our old common stock for each quarter of the calendar year 2007, as reported on the Pink Sheets and high and low sales prices for reorganized Calpine Corporation common stock for each quarter of the calendar year 2008, as reported on the NYSE. OTC market quotations reflect inter-dealer prices, without retail mark-up, mark-down or commissions, and may not necessarily reflect actual transactions.

	High	Low	Market/Report
2008			
First Quarter	$ 19.51	$ 15.00	NYSE
Second Quarter	23.36	17.77	NYSE
Third Quarter	22.83	12.08	NYSE
Fourth Quarter	13.48	6.35	NYSE
2007			
First Quarter	$ 2.19	$ 1.09	Pink Sheets
Second Quarter	4.15	1.99	Pink Sheets
Third Quarter	3.75	1.05	Pink Sheets
Fourth Quarter	1.80	0.18	Pink Sheets

As of December 31, 2008, there were 124 stockholders on record of our common stock. See Note 3 of the Notes to Consolidated Financial Statements for a discussion of the effects of emergence from Chapter 11 on our capital structure.

To prevent the risk of loss of our ability to utilize our tax NOL carryforwards, our amended and restated certificate of incorporation permits our Board of Directors to meet to determine whether to impose certain transfer restrictions on our common stock in the following circumstances: if, prior to February 1, 2013, our Market Capitalization declines by at least 35% from our Emergence Date Market Capitalization of approximately $8.6 billion (calculated pursuant to our amended and restated certificate of incorporation) and at least 25 percentage points of shift in ownership has occurred with respect to our equity for purposes of Section 382 of the IRC. During 2008, and through the filing of this Report, we have experienced declines in our stock price of more than 50% from our Emergence Date Market Capitalization. As of the filing of this Report, our shift in ownership is approximately 10%.

We have filed a registration statement on Form S-3 registering the resale of the common stock held by two holders (or related groups of holders) of our common stock that collectively own approximately 47% of our common stock, which will permit them to sell a large portion of their shares of common stock without being subject to the "trickle out" or other restrictions of Rule 144 under the Securities Act. If these shareholders sought to sell all of their registered shares within a short period of time, pursuant to the Form S-3 or otherwise, it would result in a shift in ownership of greater than 25 percentage points and our Board of Directors could elect to impose certain trading restrictions on our common stock as described above.

These restrictions are not currently operative but could become operative in the future if the foregoing events occur and our Board of Directors elect to impose them. There can be no assurance that the circumstances will not be met in the future, or in the event that they are met, that our Board of Directors would choose to impose these restrictions or that, if imposed, such restrictions would prevent an ownership change from occurring.

We have never paid cash dividends on our common stock. We are currently prohibited from paying any cash dividends on our common stock because our ability to pay cash dividends is restricted under the Exit Credit Facility and certain of our other debt agreements, and it is not anticipated that any cash dividends will be paid on our common stock in the near future. Future cash dividends, if any, will be at the discretion of our Board of Directors and will depend upon, among other things, our future operations and earnings, capital requirements, general financial condition, contractual restrictions and such other factors as our Board of Directors may deem relevant. See Item 1A. "Risk Factors," including "— Risks Relating to Our Common Stock" for a discussion of additional risks related to an investment in our common stock.

Inducement Options. On August 10, 2008, in connection with the hiring of Jack A. Fusco, our President and Chief Executive Officer, we granted options to Mr. Fusco to purchase 4,144,000 shares of common stock. Mr. Fusco's options vest over a five-year term and are exercisable at prices ranging from $15.99 to $23.99 per share. On August 12, 2008, in connection with the hiring of W. Thaddeus Miller, our Executive Vice President, Chief Legal Officer and Secretary, we granted options to Mr. Miller to purchase 428,000 shares of common stock. Mr. Miller's options vest over a five-year term and are exercisable at prices ranging from $16.60 to $23.99 per share. Finally, on September 1, 2008, in connection with the hiring of John B. (Thad) Hill, our Executive Vice President and Chief Commercial Officer, we granted options to Mr. Hill to purchase 64,734 shares of common stock. Mr. Hill's options vest over a five-year term and are exercisable at prices ranging from $18.00 to $27.00 per share. We did not receive any payment in connection with the option grants. The issuance of the options was exempt from registration under Section 4(2) under the Securities Act as a transaction not involving a public offering and exempt from registration under Section 12(g) of the Exchange Act pursuant to Rule 12h-1 thereunder. On November 3, 2008, we filed with the SEC a registration statement on Form S-8 with respect to the common stock underlying the options, which became effective upon filing.

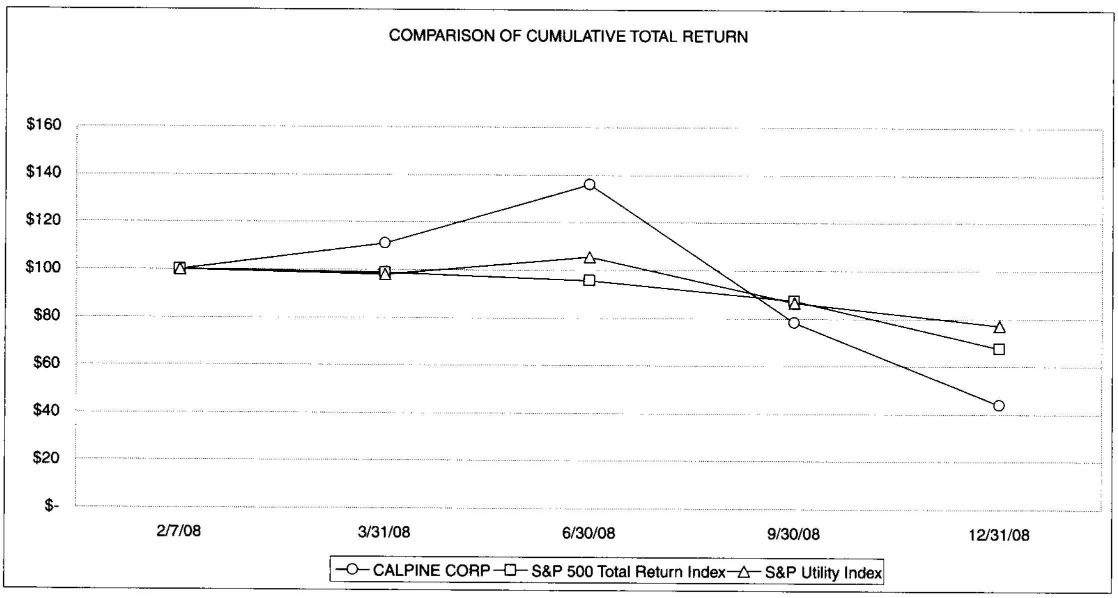
Repurchase of Equity Securities. Upon vesting of restricted stock awarded by us to employees, we withhold shares to cover employees' tax withholding obligations, other than for employees who have chosen to make tax withholding payments in cash. As set forth in the table below, during 2008, we withheld a total of 65,032 shares in the indicated months. These were the only repurchases of equity securities made by us during 2008, and we did not repurchase any shares during the fourth quarter of 2008. We do not have a stock repurchase program.

Period	(a) Total Number of Shares Purchased	(b) Average Price Paid Per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	(d) Maximum Number of Shares That May Yet Be Purchased Under the Plans or Programs
April	473	$ 18.54	—	n/a
July	490	18.00	—	n/a
August	64,069	15.94	—	n/a
Total	65,032	15.98	—	n/a

Stock Performance Graph

The performance graph below compares cumulative return on our common stock for the period February 7, 2008, through December 31, 2008 with the cumulative return of Standard & Poor's 500 Index (S&P 500) and the S&P 500 Utility Index. Since the reorganized Calpine Corporation common stock began "regular way" trading on the NYSE on February 7, 2008, stock performance prior to February 7, 2008 does not provide meaningful comparison and has not been provided.

The graph below compares each quarterly period assuming that $100 was invested on February 7, 2008 in our common stock and each of above indices and that all dividends are reinvested. The returns shown below may not be indicative of future performance.



Company / Index	February 7, 2008	March 31, 2008	June 30, 2008	September 30, 2008	December 31, 2008
Calpine Corporation	$ 100	$ 110.96	$ 135.90	$ 78.31	$ 43.86
S&P 500 Index	100	98.94	95.74	87.12	67.56
S&P Utility Index	100	97.88	105.66	86.70	77.20

Item 6. *Selected Financial Data*

SELECTED CONSOLIDATED FINANCIAL DATA

	Years Ended December 31,				
	2008	2007	2006	2005	2004
	(in millions, except earnings (loss) per share)				
Statement of Operations data:					
Operating revenues	$ 9,937	$ 7,970	$ 6,937	$ 10,302	$ 8,645
Income (loss) before discontinued operations[1]	$ (13)	$ 2,693	$ (1,765)	$ (9,881)	$ (420)
Discontinued operations, net of tax	23	—	—	(58)	177
Net income (loss)[1]	$ 10	$ 2,693	$ (1,765)	$ (9,939)	$ (243)
Basic earnings (loss) per common share[2]:					
Income (loss) before discontinued operations[1]	$ (0.03)	$ 5.62	$ (3.68)	$ (21.32)	$ (0.97)
Discontinued operations, net of tax	0.05	—	—	(0.12)	0.41
Net income (loss)[1]	$ 0.02	$ 5.62	$ (3.68)	$ (21.44)	$ (0.56)
Diluted earnings (loss) per common share[2]:					
Income (loss) before discontinued operations[1]	$ (0.03)	$ 5.62	$ (3.68)	$ (21.32)	$ (0.97)
Discontinued operations, net of tax	0.05	—	—	(0.12)	0.41
Net income (loss)[1]	$ 0.02	$ 5.62	$ (3.68)	$ (21.44)	$ (0.56)
Balance Sheet data:					
Total assets	$ 20,738	$ 19,050	$ 18,590	$ 20,545	$ 27,216
Short-term debt and capital lease obligations[3]	716	1,710	4,569	5,414	1,029
Long-term debt and capital lease obligations[3][4]	9,756	9,946	3,352	2,462	16,941
Liabilities subject to compromise[4]	—	8,788	14,757	14,610	—

(1) As a result of our Chapter 11 and CCAA filings, for the year ended December 31, 2005, we recorded $5.0 billion of reorganization items primarily related to the provisions for expected allowed claims, impairment of our Canadian subsidiaries, guarantees, write-off of unamortized deferred financing costs and losses on terminated contracts. During 2007, we were released from a portion of our direct and indirect Canadian guarantee of the ULC I notes, ULC II notes and redundant Canadian claims and recorded a $4.1 billion credit for the reversal of these redundant claims.

(2) Although EPS information for the years ended December 31, 2007, 2006, 2005 and 2004 is presented, it is not comparable to the information presented for the year ended December 31, 2008, due to the changes in our capital structure on the Effective Date, which also included termination of all outstanding convertible securities.

(3) As a result of our Chapter 11 filings, we reclassified approximately $5.1 billion of long-term debt and capital lease obligations to short-term at December 31, 2006 and 2005, as the Chapter 11 filings constituted events of default or otherwise triggered repayment obligations for the Calpine Debtors and certain Non-Debtor entities. We classified our long-term debt and capital lease obligations at December 31, 2007, based upon the refinanced terms of our Exit Facilities. See Note 8 of the Notes to Consolidated Financial Statements for more information.

(4) LSTC include unsecured and under secured liabilities incurred prior to the Petition Date and exclude liabilities that are fully secured or liabilities of our subsidiaries or affiliates that have not made Chapter 11 filings and other approved payments such as taxes and payroll. As a result of our Chapter 11 filings, we reclassified approximately $7.5 billion of long-term debt to LSTC at December 31, 2005. We subsequently

reclassified $3.7 billion from LSTC back to long-term debt based upon the terms of our Plan of Reorganization at December 31, 2007. See Notes 3 and 8 of the Notes to Consolidated Financial Statements for more information.

See Note 3 of the Notes to Consolidated Financial Statements regarding certain "plan effect" adjustments to our Consolidated Balance Sheet as of the Effective Date.

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

Forward-Looking Information

This Management's Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with our accompanying Consolidated Financial Statements and related notes. See the cautionary statement regarding forward-looking statements on page 1 of this Report for a description of important factors that could cause actual results to differ from expected results. See also Item 1A. "Risk Factors."

INTRODUCTION AND OVERVIEW

Our Business

We are an independent wholesale power generation company engaged in the ownership and operation of natural gas-fired and geothermal power plants in North America. Our portfolio of power plants is comprised of two types of power generation technologies: natural gas-fired combustion turbines (primarily combined-cycle) and renewable geothermal conventional steam turbines. As of December 31, 2008, our portfolio, including partnership interests, consisted of 76 power plants, with an aggregate operating generation capacity of approximately 24,187 MW with an additional nearly 1,000 MW under construction or in advanced development at two power plants. Our generation capacity consisted of 4,080 MW of baseload capacity from our Geysers Assets and Cogeneration power plants (natural gas-fired power plants that produce and sell both power and steam), 15,057 MW of intermediate load capacity from our combined-cycle combustion turbines and 5,050 MW of peaking capacity from duct-fired generation and generation from our simple-cycle combustion turbines.

We sell wholesale power, steam, capacity, renewable energy credits and ancillary services to our customers, including industrial companies, retail power providers, utilities, municipalities, independent electric system operators, marketers and others. We engage in the purchase of natural gas as fuel for our power plants and in related natural gas transportation and storage transactions, and in the purchase of electric transmission rights to deliver power to our customers. We also enter into natural gas, power and other financial derivative and commodities transactions to hedge our business risks and optimize our portfolio. We seek to grow our business through financially disciplined power plant development, construction and acquisition as well as through expansion or upgrades of our existing power plants, in each case, based primarily on whether we expect to achieve an attractive return on invested capital.

During 2006 and through the Effective Date, we conducted our business in the ordinary course as debtors-in-possession under the protection of the Bankruptcy Courts. We emerged from Chapter 11 on January 31, 2008, as described below in "— Emergence from Chapter 11 and Implementation of Plan of Reorganization."

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

Ongoing state, regional and federal initiatives to implement new environmental regulations are expected to have a significant impact on the power generation industry. At the federal level, there has been increased attention to climate change, RPS and energy efficiency. Several bills to regulate GHG emissions and to impose a national RPS and energy efficiency standards, as well as to provide economic incentives to develop and operate renewable power generation and energy efficiency, have already been introduced in Congress. Several states and regional organizations are also developing, or have developed, state-specific or regional initiatives to reduce GHG emissions and to promote RPS and energy efficiency through mandatory programs. We are actively participating in these debates at the federal, state and regional levels. Although the ultimate legislation and regulations that result from these activities could have a material impact on our business, we believe we will face a lower compliance burden than some competitors due to the relatively low GHG emission rates of our fleet; however, it is too early to determine the likely impact of proposed RPS and energy efficiency regulations.

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

Our Key Financial Performance Drivers

Our Commodity Margin and cash flows from operations are primarily derived from the sale of power and power-related products generated predominantly from our natural gas-fired power plant portfolio. Thus, the spread between natural gas prices and power prices contributes significantly to our financial results and is the primary component of our Commodity Margin. In addition, our plant operating performance and availability are key to our performance.

Natural gas prices and power prices are generally correlated in our two primary markets, the West and Texas, because plants using natural gas-fired technology tend to be the marginal or price-setting generation units in these regions. Holding other factors constant, where natural gas is the price-setting fuel, higher natural gas prices tend to increase our Commodity Margin because our combined-cycle plants are more fuel-efficient than many other older gas-fired technologies and peaking units. Conversely, decreases in natural gas prices tend to decrease our Commodity Margin. However, the positive relationship between natural gas prices and our Commodity Margin may be diminished by the effects of our fixed-price PPAs and where natural gas-fired units are not on the margin as is often the case in off-peak periods or in markets where non-gas-fired capacity can satisfy the majority of the demand. Our Geysers Assets do not consume natural gas, and because there is a direct relationship between power prices and natural gas prices in the West, increases in natural gas prices generally benefit our Geysers Assets.

Weather could have a significant short-term impact on supply and demand. Historically, demand for and the price of power is higher in the summer and winter seasons when temperatures are more extreme, and therefore, our revenues and Commodity Margin could be negatively impacted by relatively cool summers or mild winters. Also as a result of weather patterns, a disproportionate amount of our total revenue is usually realized during our third fiscal quarter. We expect this trend to continue in the future as U.S. demand for power generally peaks during this time.

Generation outages and reserve margins also impact supply and demand and the price for power, particularly in markets where reserve margins are low or transmission constraints require that baseload generation be served from generation units operating within that market (such as in the West). In addition, efficient operation of our fleet creates the opportunity to capture Commodity Margin in a cost effective manner. However, unplanned outages during periods of positive Commodity Margin could result in a loss of that opportunity. We generally measure our fleet performance based on our availability factors, Heat Rate and plant operating expense. The higher our availability factor, the better positioned we are to capture Commodity Margin. The less natural gas we must consume for each MWh of power generated, the lower our Heat Rate and the higher our Commodity Margin.

Emergence from Chapter 11 and Implementation of Plan of Reorganization

From the Petition Date and through the Effective Date, we operated as a debtor-in-possession under the protection of the Bankruptcy Courts. We emerged from Chapter 11 on January 31, 2008. At the Petition Date, we carried $17.4 billion of debt with an average interest rate of 10.3%. As a result of retiring unsecured debt with reorganized Calpine Corporation common stock, proceeds received from the sale of certain of our assets and the repayment or refinancing of certain of our project debt, we reduced our pre-petition debt by approximately $7.0 billion. Upon our emergence from Chapter 11, we carried $10.4 billion of debt with an average interest rate of 8.1%.

Pursuant to our Plan of Reorganization, first and second lien Calpine Corporation debt claims, allowed administrative claims and unsecured convenience claims (subject to certain exceptions, all unsecured claims $50,000 or less) have been or are being paid in full in cash and cash equivalents; priority tax claims have been or are being paid in full in cash and cash equivalents or with a distribution of reorganized Calpine Corporation common stock; and other allowed secured claims have been or are being reinstated, paid in full in cash or cash equivalents, or had the collateral securing such claims turned over to the secured creditor. In addition, all shares of our common stock outstanding prior to the Effective Date were canceled, and the issuance of 485 million shares of reorganized Calpine Corporation common stock was authorized for distribution to holders of certain allowed claims, primarily holders of allowed unsecured claims. Through the filing of this Report, approximately 427 million shares have been distributed to holders of allowed unsecured claims against the U.S. Debtors, approximately 10 million shares are being held pending resolution of certain inter-creditor matters and approximately 48 million shares remain in reserve for distribution to holders of disputed claims whose claims ultimately become allowed. Any unresolved claims will continue to be subject to the claims reconciliation process under the supervision of the U.S. Bankruptcy Court. We estimate that the number of shares reserved is sufficient to satisfy the U.S. Debtors' obligations under the Plan of Reorganization even if all disputed unsecured claims ultimately become allowed. To the extent that any of the reserved shares remain undistributed upon resolution of the remaining disputed claims, such shares will not be returned to us but rather will be distributed pro rata to claimants with allowed claims to increase their recovery. We are not required to issue additional shares above the 485 million shares authorized to settle unsecured claims, even if the shares remaining for distribution are not sufficient to fully pay all allowed unsecured claims. Accordingly, resolution of these claims could have a material effect on creditor recoveries under the Plan of Reorganization as the total number of shares of common stock that remain available for distribution upon resolution of disputed claims is limited pursuant to the Plan of Reorganization.

On September 22, 2008, the U.S. Bankruptcy Court approved our settlement with the holders of the CalGen Second Lien Debt settling their claims asserted in our Chapter 11 cases for, among other things, prepayment premiums and default interest for $64 million plus interest accruing from September 30, 2008. Pursuant to the settlement, which resolved the largest disputed claims outstanding after our emergence date, unsecured claims to the holders of the CalGen Second Lien Debt were allowed $110 million in the aggregate. These unsecured claims were satisfied with distributions of 5,358,300 shares of the reorganized Calpine Corporation common stock reserved under the Plan of Reorganization.

Certain disputed claims, including prepayment premium and default interest claims asserted by the holders of CalGen Third Lien Debt, which remain disputed, may be required to be settled in cash and cash equivalents, which may be generated from the sale of the allowed claim (which claim would be an unsecured claim and therefore settled with reorganized Calpine Corporation common stock held in reserve pursuant to the Plan of Reorganization). To the extent that the common stock reserved on account of the CalGen Third Lien Debt prepayment premium and default interest claims is insufficient in value to satisfy such claims in full, we will be required to use other available cash to satisfy such claims unless otherwise approved by the U.S. Bankruptcy Court. No assurances can be given that settlements may not be materially higher or lower than confirmed in the Plan of Reorganization or than we originally estimated.

Pursuant to the Plan of Reorganization, we were also authorized to issue up to 15 million shares under the Calpine Equity Incentive Plans, and, as of December 31, 2008, approximately 2 million shares of restricted stock, net of forfeitures, and options to purchase approximately 9 million shares of common stock, net of forfeitures, had been issued under the Calpine Equity Incentive Plans. Holders of allowed interests in Calpine Corporation (primarily holders of Calpine Corporation common stock existing as of the Petition Date) received a pro rata share of warrants to purchase approximately 48.5 million shares of reorganized Calpine Corporation common stock at $23.88 per share. Warrants for 21,499 shares of common stock were exercised prior to expiration. The remaining unexercised warrants expired on August 25, 2008. Holders of subordinated equity securities claims did not receive a distribution under the Plan of Reorganization and may only recover from applicable insurance proceeds.

Upon the application of the Canadian Debtors and other foreign entities, on February 8, 2008, the Canadian Court ordered and declared that (i) the unsecured notes issued by ULC I were canceled and discharged on February 4, 2008, (ii) the Canadian Debtors and other foreign entities had completed all distributions previously ordered in full satisfaction of the pre-filing claims against them, (iii) the Canadian Debtors and other foreign entities had otherwise fully complied with all orders of the Canadian Court and (iv) the proceedings under the CCAA were terminated, including the stay of proceedings. As a result of the termination of the CCAA proceedings, the Canadian Debtors and other foreign entities, consisting of a 50% ownership interest in the 50 MW Whitby Cogeneration power plant, approximately $34 million of debt and various working capital items, were reconsolidated on the Canadian Effective Date.

In connection with our emergence from Chapter 11, we recorded certain "plan effect" adjustments to our Consolidated Balance Sheet as of the Effective Date in order to reflect certain provisions of our Plan of Reorganization. These adjustments included the distribution of approximately $4.1 billion in cash and the authorized issuance of 485 million shares of reorganized Calpine Corporation common stock primarily for the discharge of LSTC, repayment of the Second Priority Debt and for various other administrative and other post-petition claims. As a result, our equity increased by approximately $8.9 billion. We borrowed approximately $6.4 billion under our Exit Facilities, which was used to repay the outstanding term loan balance of $3.9 billion (excluding the unused portion under the $1.0 billion revolver) under our DIP Facility. The remaining net proceeds of approximately $2.5 billion were used to fund cash payment obligations under the Plan of Reorganization including the repayment of a portion of the Second Priority Debt and the payment of administrative claims. The reorganization items on our Consolidated Statements of Operations are primarily driven by our financing and restructuring activities. Our historical financial performance during the pendency of the Chapter 11 cases and CCAA proceedings is likely not indicative of our future financial performance.

See Note 3 of the Notes to Consolidated Financial Statements for further information regarding our Chapter 11 proceedings and our emergence from Chapter 11.

LIQUIDITY AND CAPITAL RESOURCES

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

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

As of December 31, 2008, we had $1.7 billion in cash and cash equivalents including $725 million borrowed on October 2, 2008, under our Exit Credit Facility revolving facility. This borrowing, which was invested in money market funds, which are mainly invested in U.S. Treasury securities or other obligations issued or guaranteed by the U.S. government, its agencies or instrumentalities, was a proactive financial decision to increase our cash position and reduce the risk of nonperformance from institutions that hold a commitment in our Exit Credit Facility revolving facility during a period of uncertainty in the capital markets. Our remaining availability under our Exit Credit Facility revolving facility as of December 31, 2008, is approximately $16 million for future letters of credit or cash borrowings. Our decision to repay, hold or pay down other debt with the cash collected from our $725 million draw under our Exit Credit Facility revolving facility will be determined based upon our future liquidity needs and confidence in future credit markets. We have $716 million in current maturities of long-term debt as of December 31, 2008. We believe that we have adequate resources to repay our current maturities as they become due with a combination of cash and cash equivalents on hand and cash expected to be generated from future operations. In the event confidence in the credit markets returns and if we are able to obtain favorable credit terms, we may decide to refinance portions of our current maturities or other more costly debt.

Significant changes in commodity prices and Market Heat Rates can have an impact on our liquidity as we use margin deposits, cash prepayments and letters of credit as credit support (collateral) with and from our counterparties for commodity procurement and risk management activities. Utilizing our portfolio of transactions subject to collateral exposure, we estimate that, as of February 11, 2009, an increase of $1/MMBtu in natural gas prices would result in an increase of collateral required of approximately $154 million. If natural gas prices decreased by $1/MMBtu, we estimate that our collateral requirements would decrease by approximately $143 million. Changes in Market Heat Rates also affect our liquidity. For example, as demand increases, less efficient generation is dispatched, which increases the Market Heat Rate and results in increased collateral requirements. Based upon historical relationships of natural gas and Market Heat Rate movements, we derived a statistical analysis that indicates that a change of $1/MMBtu in natural gas is comparable to a Market Heat Rate change of 170 Btu/KWh. We estimate that, as of February 11, 2009, an increase of 170 Btu/KWh in the Market Heat Rate would result in an increase in collateral required of approximately $40 million. If Market Heat Rates were to fall at a similar rate, we estimate that our collateral required would decrease by $24 million. In the second quarter of 2008, we experienced higher commodity prices and Market Heat Rates which exposed us to increasing collateral requirements and margin calls which then decreased in the third quarter.

In order to reduce the cash collateral and letters of credit that we would otherwise be required to provide to our counterparties, we have granted additional liens on the assets currently subject to liens under the Exit Credit Facility to collateralize our obligations under certain of our power and natural gas agreements that qualify as "eligible commodity hedge agreements" under the Exit Credit Facility, and certain of our interest rate swap agreements. The counterparties under such agreements will share the benefits of the collateral subject to such liens ratably with the lenders under the Exit Credit Facility. Such liens had also been permitted under the DIP Facility prior to the conversion of the loans and commitments under the DIP Facility to our exit financing under the Exit Credit Facility. See Note 11 of the Notes to Consolidated Financial Statements for further information on our margin deposits and collateral used for commodity procurement and risk management activities.

To provide for increased liquidity in periods of rising commodity prices, we entered into two credit facilities, the Knock-in Facility and Commodity Collateral Revolver that increase our liquidity available to collateralize obligations to counterparties under eligible commodity hedge agreements during periods of increasing natural gas prices. The Knock-in Facility, maturing on June 25, 2009, provides an initial $50 million of available capacity for the issuance of letters of credit up to a total maximum availability of $200 million contingent on natural gas futures contract prices exceeding certain thresholds. The Commodity Collateral Revolver, maturing July 8, 2010, under which we received an initial advance of $100 million, provides up to a total maximum availability of $300 million contingent on mark-to-market exposure amounts under certain reference transactions. As of the date of this Report, no additional amounts under either facility are available as current natural gas prices do not exceed stated thresholds.

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

It is difficult to predict future developments and the amount of credit support that we may need to provide as part of our business operations should financial market and commodity price volatility persist for a significant period of time beyond 2009. Our ability to generate sufficient cash is dependent upon, among other things: (i) improving the profitability of our operations; (ii) complying with the covenants under our Exit Credit Facility and other existing financing obligations; (iii) stabilizing and increasing future contractual cash flows; and (iv) our significant counterparties performing under their contracts with us.

Our significant financing activities and debt agreements entered into during the year ended December 31, 2008, are summarized below.

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

- The Exit Credit Facility, comprising (i) approximately $6.0 billion of senior secured term loans; (ii) a $1.0 billion senior secured revolving facility; and (iii) the ability to raise up to $2.0 billion of incremental term loans available on a senior secured basis in order to refinance secured debt of subsidiaries under an "accordion" provision; and

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

On the Effective Date, we fully drew on our approximately $6.0 billion of senior secured term loans and the $300 million Bridge Facility and we drew approximately $150 million under the $1.0 billion senior secured revolving facility. The proceeds of the drawdowns, above the amounts that had been applied under the DIP Facility as described below, were used to repay a portion of the Second Priority Debt, fund distributions under the Plan of Reorganization to holders of other secured claims and to pay fees, costs, commissions and expenses in connection with the Exit Facilities and the implementation of our Plan of Reorganization. Term loan borrowings under the Exit Credit Facility bear interest at a floating rate of, at our option, LIBOR plus 2.875% per annum or base rate plus 1.875% per annum. Borrowings under the Exit Credit Facility term loan facility require quarterly payments of principal equal to 0.25% of the original principal amount of the term loan, with the remaining unpaid amount due and payable at maturity on March 29, 2014.

The Bridge Facility was repaid in full on March 6, 2008, with proceeds from the sales of the Hillabee and Fremont development project assets.

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

- Incur additional indebtedness and issue stock;
- Make prepayments on or purchase indebtedness in whole or in part;
- Pay dividends and other distributions with respect to our stock or repurchase our stock or make other restricted payments;
- Use money borrowed under the Exit Credit Facility for non-guarantors (including foreign subsidiaries);
- Make certain investments;
- Create or incur liens to secure debt;
- Consolidate or merge with another entity, or allow one of our subsidiaries to do so;
- Lease, transfer or sell assets and use proceeds of permitted asset leases, transfers or sales;
- Limit dividends or other distributions from certain subsidiaries up to Calpine Corporation;
- Make capital expenditures beyond specified limits;
- Engage in certain business activities; and
- Acquire facilities or other businesses.

The Exit Credit Facility also requires compliance with financial covenants that include (i) a maximum ratio of total net debt to Consolidated EBITDA (as defined in the Exit Credit Facility), (ii) a minimum ratio of Consolidated EBITDA to cash interest expense and (iii) a maximum ratio of total senior net debt to Consolidated EBITDA. We were in compliance with all our covenants related to our Exit Credit Facility at December 31, 2008.

As of December 31, 2008, under the Exit Credit Facility we had approximately $5.9 billion outstanding under the term loan facilities, $725 million outstanding under the revolving credit facility and $259 million of letters of credit issued against the revolving credit facility.

Other Financing Activities — On February 1, 2008, Blue Spruce, an indirect wholly owned subsidiary, entered into a $90 million senior term loan. Net proceeds from the senior term loan were used to refinance all outstanding indebtedness under the existing Blue Spruce term loan facility, to pay fees and expenses related to the transaction and for general corporate purposes. The senior term loan carries interest at a base rate plus 0.63% which escalates to 1.50% or LIBOR plus 1.63%, which escalates to 2.50% over the life of the senior term loan and matures December 31, 2017. The senior term loan is secured by the assets of Blue Spruce. In connection with this refinancing, we recorded $7 million in loss on debt extinguishment, related to the write-off of deferred financing costs of $4 million and prepayment penalties of $3 million, which are recorded in other (income) expense, net on our Consolidated Statements of Operations.

During the first quarter of 2008, we entered into a letter of credit facility related to our subsidiary Calpine Development Holdings, Inc. under which up to $150 million is available for letters of credit. As of December 31, 2008, $148 million in letters of credit had been issued and were outstanding under this facility.

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

On June 25, 2008, we entered into the Knock-in Facility, a 12-month, $200 million letter of credit facility. Our obligations under the Knock-in Facility are unsecured. Availability of letters of credit for issuance under the Knock-in Facility is up to a total maximum availability of $200 million contingent on natural gas futures contract prices exceeding certain thresholds, with initial availability for up to $50 million. As of December 31, 2008, $50 million in letters of credit had been issued and were outstanding under this facility.

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

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

On January 21, 2009, Deer Park, our indirect wholly owned subsidiary, closed on $156 million of senior secured credit facilities, which include a $150 million term facility and a $6 million letter of credit facility. Proceeds received were used to repay an existing obligation of approximately $79 million, pay financing and legal fees of approximately $7 million, fund approximately $15 million in restricted cash and the remainder was distributed to Calpine Corporation for general corporate purposes. The senior term loan facility matures on January 21, 2012, and bears interest at Deer Park's option of LIBOR plus 3.5% or base rate plus 2.5%.

Letter of Credit Facilities — The table below represents amounts outstanding under our letter of credit facilities as of December 31, 2008 and 2007 (in millions):

	2008	2007
Exit Credit Facility	$ 259	$ —
DIP Facility	—	235
Calpine Development Holdings, Inc.	148	—
Knock-in Facility	50	—
Various project financing facilities	99	113
Total	$ 556	$ 348

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

We are currently prohibited from paying any cash dividends on our common stock in the foreseeable future because our ability to pay cash dividends is restricted under the Exit Credit Facility and certain of our other debt agreements. Future cash dividends, if any, will be at the discretion of our Board of Directors and will depend upon, among other things, our future operations and earnings, capital requirements, general financial condition, contractual restrictions and such other factors as our Board of Directors may deem relevant.

NOLs — We have significant NOLs that will provide future tax deductions if we generate sufficient taxable income during the carryover periods. As of December 31, 2008, our consolidated federal NOLs totaled approximately $7.5 billion, which consists of approximately $7.1 billion from Calpine Corporation and its subsidiaries other than CCFC, and approximately $396 million from our CCFC subsidiaries. We have recorded a valuation allowance against most of these losses as we determined it is more likely than not, that they will expire unutilized. Approximately $5.6 billion of our NOLs have annual limitations under Section 382 of the IRC. Amounts subject to limitations, but not used, can be carried forward to succeeding years. We also generated approximately $2.0 billion in NOLs in 2008. Approximately 90% of these NOLs will not be subject to annual limitation under Section 382 of the IRC unless we experience another ownership change before they are used. In addition, we have approximately $1.0 billion in foreign NOLs with a full valuation allowance.

Major Maintenance, Capital Spending and Project Financing — Our major maintenance and capital spending remains an important part of our business. Our expected capital expenditures for 2009 are the following (in millions):

	2009
Major maintenance and maintenance expense	$ 205
Capital expenditures, operations	145
Total capital spending	$ 350

In addition, we expect to incur approximately $175 million in 2009 for construction of new power plants, of which, approximately $131 million is expected to be funded with project debt. Our expected capital expenditures for each of the next five years for major maintenance, maintenance expense and for operations are expected to average approximately $300 million.

We have one consolidated project, Russell City Energy Center, in active development. The Russell City Energy Center is currently contracted to deliver its full output to PG&E under a PPA which was executed in

December 2006 and approved by the CPUC in January 2007. The PPA was amended in 2008 and is now before the CPUC for approval as amended. All permits for the projects have been issued and approved with the exception of an air permit now pending before the local air quality board. Under the amended PPA, the expected commercial operation date has been extended by two years from 2010 to June 2012. Completion of the Russell City Energy Center is dependent upon obtaining the necessary permits, regulatory approvals, construction contracts and construction funding under project financing facilities. We do not expect the costs to complete the Russell City Energy Center to be material to us on a consolidated basis. Upon completion, this project would bring on line approximately 362 MW of net interest baseload capacity (390 MW with peaking capacity) representing our 65% share.

We hold all of the equity interest in one unconsolidated project under construction at December 31, 2008, Otay Mesa Energy Center, which is expected to achieve commercial operations in 2009. The completion of Otay Mesa Energy Center will bring on line approximately 596 MW of net interest baseload (with peaking) capacity. We also own a 50% equity interest in the Greenfield Energy Centre, which achieved commercial operations on October 17, 2008. Our net interest baseload (with peaking) capacity increased as a result of Greenfield Energy Centre by approximately 503 MW representing our 50% share.

Cash Flow Activities — The following table summarizes our cash flow activities for the years ended December 31, 2008, 2007 and 2006 (in millions):

	2008	2007	2006
Beginning cash and cash equivalents	$ 1,915	$ 1,077	$ 786
Net cash provided by (used in):			
Operating activities	$ 494	$ 187	$ 12
Investing activities	516	473	158
Financing activities	(1,268)	178	121
Net increase (decrease) in cash and cash equivalents	$ (258)	$ 838	$ 291
Ending cash and cash equivalents	$ 1,657	$ 1,915	$ 1,077

2008 — 2007

Net Cash Provided By Operating Activities

Cash flows provided by operating activities for the year ended December 31, 2008, resulted in net inflows of $494 million as compared to net inflows of $187 million for the same period in 2007. Cash flows from operating activities were primarily due to increases in:

- *Gross profit* — Gross profit, excluding changes in depreciation and impairments, increased by $222 million in 2008 primarily due to higher spark spreads resulting from high gas prices during the first half of the year. The favorable margins were partially offset by higher plant operating expenses.

- *Interest paid* — Cash paid for interest decrease by $83 million in 2008 to $1,060 million for the year ended December 31, 2008, as compared to $1,143 million in 2007, primarily due to additional adequate protection payments on our Second Priority Debt in 2007.

- *Working capital* — Working capital employed relating to operating assets and liabilities changed by approximately $53 million during the year, after adjusting for actual cash flows from derivative activities that are included in net derivative assets and liabilities. This increase in 2008 was primarily the result of a slight increase in inventory levels as compared to 2007.

Net Cash Provided By Investing Activities

Cash flows provided by investing activities for the year ended December 31, 2008, increased by $43 million to $516 million from $473 million for the year ended December 31, 2007. The difference was primarily due to:

- *Capital expenditures* — Purchases for property, plant and equipment decreased by $53 million in 2008 as compared to 2007.
- *Sales of power plants, turbines and investments* — Proceeds from asset sales decreased by $128 million in 2008 compared to 2007. See Note 7 of the Notes to Consolidated Financial Statements for a list of assets sold during 2008 and 2007.
- *Sale of discontinued operations* — Proceeds of $79 million were received in 2008 from the sale of Rosetta.
- *Deconsolidation and reconsolidation* — We experienced a favorable effect on cash of $64 million from the reconsolidation of our Canadian Debtors and other foreign entities in 2008, as compared to an unfavorable effect on cash of $29 million for the deconsolidation of OMEC in 2007.
- *Contributions to unconsolidated investments* — Contributions decreased by $51 million in 2008 primarily due to the completion of the Greenfield LP project financing in May 2007.
- *Return of investment from unconsolidated investments* — For the year ended December 31, 2008, we received cash of $27 million as a partial return of investment compared to $104 million received from Greenfield LP and $75 million related to the Canadian Debtors and other foreign entities for the year ended December 31, 2007.
- *Reduced restricted cash requirements* — The net reduction in restricted cash was $78 million in 2008, down by $41 million to $37 million in 2007. Restricted cash decreased in 2008 mainly due to paying down debt and refinancing activities.

Net Cash Provided By (Used In) Financing Activities

Cash flows used in financing activities for the year ended December 31, 2008, resulted in net outflows of approximately $1.3 billion, as compared to cash provided by financing activities of $178 million for the year ended December 31, 2007; because of our emergence from Chapter 11 in 2008, our cash flows provided by/used in our financing activities are not comparable to 2007. The significant transactions and changes in our financing activities as compared to 2007 are described below:

- *Borrowings and repayments under the Exit Facilities* — On and subsequent to the Effective Date, we borrowed $4.2 billion under our Exit Facilities and used cash on hand to repay a portion of the Second Priority Debt and to fund other cash payment obligations under the Plan of Reorganization, working capital and other general corporate purposes. In addition, for the year ended December 31, 2008, we repaid approximately $1.5 billion of borrowings under our Exit Facilities consisting of the repayment of the $300 million Bridge Facility, with the remainder applied to repayments under our Exit Credit Facility, primarily the revolving facility thereunder, and $725 million of which amount was subsequently reborrowed in October 2008. For the year ended December 31, 2007, borrowings under our DIP Facility resulted in cash inflows of $614 million.
- *Repayment of debt obligations* — During 2008 we repaid $311 million for project financing, which primarily related to the Metcalf and Blue Spruce refinancings. During 2007, the repayment of debt obligations, in general, related to only those project finance facilities and other borrowings associated with the Non-Debtors, except as otherwise ordered by the Bankruptcy Courts such as the repayment of $224 million of CalGen Secured Debt.

- *Financing costs* — We incurred financing costs of $207 million, primarily related to closing on our Exit Facilities in 2008, as compared to financing costs incurred in 2007 of $81 million primarily related to the refinancing in March 2007 of the Original DIP Facility with the DIP Facility.

- *Preferred interests* — For the year ended December 31, 2008, we paid $166 million for the redemption or repayment of preferred interests primarily consisting of the repayment of $155 million in preferred interests related to Metcalf, as compared to $9 million for the year ended December 31, 2007.

- *Derivative contracts* — We received $64 million from the settlement of derivatives with an other-than-insignificant financing element for the year ended December 31, 2008.

2007 – 2006

Net Cash Provided By Operating Activities

Cash flows provided by operating activities for the year ended December 31, 2007, resulted in net inflows of $187 million as compared to net inflows of $12 million for the same period in 2006. Cash flows from operating activities were primarily due to:

- *Gross profit* — Gross profit, excluding changes in depreciation and impairments, increased by $139 million in 2007 due mainly to higher spark spreads on open positions predominantly in the West and Southeast resulting from warmer temperatures in 2007, and increased hydroelectric production in the Pacific Northwest during 2006, which lowered 2006 spark spreads in the West.

- *Interest paid* — Cash paid for interest increased by $164 million in 2007 to $1,143 million for the year ended December 31, 2007, as compared to $979 million in 2006, primarily due to additional adequate protection payments on our Second Priority Debt.

- *Other (income) expense* — Other (income) expense increased for the year ended December 31, 2007, compared to the year ended December 31, 2006, primarily as a result of $135 million in income relating to a claim settlement with a customer. In November 2007 we received proceeds of $135 million from the sale of the general unsecured allowed claim.

- *Working capital* — Working capital employed relating to operating assets and liabilities changed by approximately $101 million. The increase was primarily due to increases in margin deposits and gas prepayments in 2007 due in part to higher generation and fuel consumption.

Net Cash Provided By Investing Activities

Cash flows from investing activities for the year ended December 31, 2007, increased $315 million as compared to 2006. The difference was primarily due to:

- *Capital expenditures* — Purchases of property, plant and equipment decreased by $16 million to $196 million for the year ended December 31, 2007, as compared to $212 million in 2006.

- *Sale of power plant, turbines and investments* — Proceeds from asset sales in 2007 were $541 million compared to $275 million 2006. See Note 7 of the Notes to Consolidated Financial Statements for a list of assets sold during 2007. During the year ended December 31, 2007, we did not have any outflows of cash relating to acquisitions, as compared to outflows of $267 million in 2006 for the purchase of the Geysers Assets.

- *Return on investments from unconsolidated investments* — Investing activity relating to our equity method investments included a $104 million return of investment in Greenfield LP and $75 million related to the Canadian Debtors and other foreign entities.

- *Cash effect of deconsolidation of VIEs* — In 2007, we had a $29 million decrease in cash related to the deconsolidation of OMEC.

- *Reduced restricted cash requirements* — Restricted cash decreased by $347 million to $37 million for the year ended December 31, 2007, compared to $384 million for 2006. The decrease in restricted cash during the year ended December 31, 2006, was primarily due to the repayment of the First Priority Notes.

Net Cash Provided By Financing Activities

Cash flows from financing activities for the year ended December 31, 2007, resulted in net inflows of $178 million, as compared to net inflows of $121 million in 2006. The difference was primarily due to:

- *DIP Facility borrowings* — Borrowings under the DIP Facility were $614 million in 2007. We used part of the borrowings to repay $224 million of CalGen Secured Debt. The remaining borrowings were mainly used for working capital and other general corporate purposes. This compares to borrowings of approximately $1.2 billion under the Original DIP Facility in 2006.

- *Repayment of debt obligations* — During 2007, we repaid $224 million related to the CalGen financing (see "DIP Facility borrowing" above), $135 million for notes payable and other lines of credit, $119 million for project financing and $38 million related to the DIP Facility. During 2006, our repayments included a $646 million non-recurring repayment related to the First Priority Notes, $180 million for notes payable and other lines of credit, $179 million related to the DIP Facility and $110 million for project financings.

- *Sale of ULC I bonds* — We received $151 million in proceeds in 2007 from the sale of bonds issued by ULC I that were held by us.

- *Project financing activity* — During 2007, we borrowed $21 million from project financing compared to $141 million in 2006.

- *Financing costs* — We paid financing fees of $81 million in 2007, primarily related to the DIP Facility, as compared to $39 million in 2006, related to the Original DIP Facility.

Counterparties and Customers — Our counterparties primarily consist of three categories of entities who participate in the wholesale energy markets: financial institutions and trading companies; regulated utilities, municipalities, cooperatives and other retail power suppliers; and oil, natural gas, chemical and other energy-related industrial companies. We have exposure to trends within the energy industry, including declines in the creditworthiness of our marketing counterparties. Currently, multiple companies within the energy industry have below investment grade credit ratings. However, we do not currently have any significant exposures to counterparties that are not paying on a current basis.

Our credit rating is largely the result of a high debt balance, limited liquidity, unproven and uncertain future cash flows and a large portion of merchant sales which require a significant amount of hedging to increase the reliability of our cash flows. Our credit rating has, among other things, generally resulted in an increase in the amount of collateral required of us by our hedging counterparties and also reduced the number of hedging counterparties willing to extend credit to us and reduced our ability to negotiate more favorable terms with them. However, we believe that we will continue to be able to work with our hedging counterparties to execute beneficial hedge transactions and provide adequate collateral.

Asset Sales and Purchase — A significant component of our restructuring activities was to return our focus to our core strategic assets. As a result of the review of our asset portfolio performed during our Chapter 11 restructuring, during 2006, 2007 and 2008, and through the filing of this Report, we have sold or otherwise disposed of certain assets, and purchased one asset, as described in the following table:

Asset	Transaction Description	Closing Date	Consideration
2008:			
Fremont development project	Sale of assets	March 5, 2008	$254 million
Hillabee development project	Sale of assets	February 14, 2008	$156 million
RockGen Energy Center	Purchase of assets	January 15, 2008	$145 million allowed unsecured claim
2007:			
Acadia PP	Sale of 50% equity interest	September 13, 2007	$104 million in cash, plus the payment of $85 million priority distributions due to Cleco
Parlin Power Plant	Sale of assets	July 6, 2007	$3 million, plus the agreement to waive certain claims
PSM	Sale of assets	March 22, 2007	$242 million
Goldendale Energy Center	Sale of assets	February 21, 2007	$120 million
Aries Power Plant	Sale of assets	January 16, 2007	$234 million(1)
2006:			
Fox Energy Center	Sale of leasehold interest	October 11, 2006	$16 million, plus the extinguishment of $352 million in debt
Dighton Power Plant	Sale of assets	October 1, 2006	$90 million
TTS	Sale of entire equity interest	September 28, 2006	$24 million
Rumford and Tiverton Power Plants	Turnover to lenders	June 23, 2006	n/a

(1) As part of the sale we were also required to use a portion of the proceeds 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.

In addition, in August 2008, Pomifer, an unrelated party, exercised its option to purchase an additional cash distribution of 20% through 2013 in our Auburndale subsidiary. Pomifer subsequently exercised its drag-along rights, which required us to sell our remaining equity interest in Auburndale in November 2008. We recorded an impairment charge of approximately $180 million for the year ended December 31, 2008 and received total proceeds of $15 million related to these transactions. See Note 5 of the Notes to Consolidated Financial Statements for further information regarding our investment in Auburndale.

See Note 7 of the Notes to Consolidated Financial Statements for further information related to these asset sales and purchase.

Credit Considerations — Our Exit Credit Facility has been rated B+ by Standard and Poor's and B2 by Moody's Investors Service and our corporate rating has been rated B by Standard and Poor's and B2 by Moody's Investors Service as of December 31, 2008.

Off Balance Sheet Commitments of Our Power Plant Operating Leases and Our Unconsolidated Subsidiaries — Some of our power plant operating leases include certain sale/leaseback transactions that are not reflected on our balance sheet. All counterparties in these transactions are third parties that are unrelated to us. The sale/leaseback transactions utilize special-purpose entities formed by the equity investors with the sole purpose of owning a power plant. Some of these operating leases contain customary restrictions on dividends, additional debt and further encumbrances similar to those typically found in project finance debt instruments. We have no ownership or other interest in any of these special purpose entities. See Note 16 of the Notes to Consolidated Financial Statements for the future minimum lease payments under our power plant operating leases.

Some of our unconsolidated equity method investments have debt that is not reflected on our Consolidated Balance Sheets. As of December 31, 2008, our equity method investees (Greenfield LP, OMEC and Whitby) had aggregate debt outstanding of $697 million. Based on our pro rata share of each of the investments, our share of such debt would be approximately $477 million. All such debt is non-recourse to us. See Note 5 of the Notes to Consolidated Financial Statements for additional information on our investments.

Guarantee Commitments — Our primary commercial obligations as of December 31, 2008, are as follows (in millions):

	Amounts of Commitment Expiration per Period						
Guarantee Commitments	**2009**	**2010**	**2011**	**2012**	**2013**	**Thereafter**	**Total Amounts Committed**
Guarantee of subsidiary debt[1]	$ 85	$ 73	$ 72	$ 70	$ 66	$ 701	$ 1,067
Standby letters of credit[2][4]	510	18	28	—	—	—	556
Surety bonds[3][4][5]	—	—	—	—	—	4	4
Guarantee of subsidiary operating lease payments[4]	10	10	67	5	5	221	318
Total	$ 605	$ 101	$ 167	$ 75	$ 71	$ 926	$ 1,945

(1) Represents our guarantees of certain project financings, facility operating leases, other miscellaneous debt and related interest. All of such guaranteed debt is recorded on our Consolidated Balance Sheets.

(2) The standby letters of credit disclosed above include those disclosed in Note 8 of the Notes to Consolidated Financial Statements.

(3) The majority of surety bonds do not have expiration or cancellation dates.

(4) These are off balance sheet obligations.

(5) As of December 31, 2008, $4 million of cash collateral is outstanding related to these bonds.

Contractual Obligations — Our contractual obligations related to continuing operations as of December 31, 2008 are as follows (in millions):

	2009	2010	2011	2012	2013	Thereafter	Total
Total operating lease obligations[1]	$ 63	$ 54	$ 110	$ 47	$ 47	$ 367	$ 688
Debt[2]	$ 704	$ 421	$ 1,807	$ 122	$ 126	$ 7,224	$ 10,404
Interest payments on debt[3]	$ 549	$ 480	$ 450	$ 375	$ 380	$ 456	$ 2,690
Interest rate swap agreement payments[3]	$ 198	$ 156	$ 97	$ 76	$ 2	$ 1	$ 530
Purchase obligations:							
Turbine commitments	16	—	13	—	—	—	29
Commodity purchase obligations[4]	1,002	496	444	405	352	4,429	7,128
Land leases	8	8	6	6	6	348	382
LTSAs	15	14	11	6	5	44	95
Other purchase obligations[5]	107	83	110	62	48	980	1,390
Total purchase obligations[6]	$ 1,148	$ 601	$ 584	$ 479	$ 411	$ 5,801	$ 9,024
Liability for uncertain tax positions	$ 28	$ —	$ 4	$ —	$ —	$ 18	$ 50
Other contractual obligations[7]	$ 55	$ 3	$ —	$ —	$ 1	$ 54	$ 113

(1) Included in the total are future minimum payments for power plant operating leases, and office and equipment leases. See Note 16 of the Notes to Consolidated Financial Statements for more information.

(2) A note payable totaling $89 million associated with the sale of the PG&E note receivable to a third party is excluded from debt for this purpose as it is a non-cash liability.

(3) Amounts are projected based upon interest rates at December 31, 2008.

(4) The amounts presented here include contracts for the purchase, transportation, or storage of commodities accounted for as executory contracts or as a normal purchase normal sale and, therefore, not recognized as liabilities on our Consolidated Balance Sheets. See "— Risk Management and Commodity Accounting" for a discussion of our commodity derivative contracts recorded at fair value on our Consolidated Balance Sheets.

(5) The amounts include obligations under employment agreements.

(6) The amounts included above for purchase obligations include the minimum requirements under contract. Agreements that we can cancel without significant cancellation fees are excluded.

(7) $52 million and $61 million represent cash obligations included in other current liabilities and long-term liabilities, respectively, on our Consolidated Balance Sheet as of December 31, 2008.

Special Purpose Subsidiaries — Pursuant to applicable transaction agreements, we have established certain of our entities separate from Calpine and our other subsidiaries. In accordance with applicable accounting standards, we consolidate these entities. As of the date of filing this Report, these entities included: Rocky Mountain Energy Center, LLC, Riverside Energy Center, LLC, Calpine Riverside Holdings, LLC, PCF, PCF III, GEC Holdings, LLC, Gilroy Energy Center, LLC, Creed Energy Center, LLC, Goose Haven Energy Center, LLC, Calpine Gilroy Cogen, L.P., Calpine Gilroy 1, Inc., 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.), CCFCP and Russell City Energy Company, LLC. The following disclosures are required under certain applicable agreements and pertain to some of these entities. The financial information provided below represents the assets, liabilities, and results of operations for each of the special purpose subsidiaries as reflected on our Consolidated Financial Statements. These amounts may differ materially from the assets, liabilities, and results of operations for these entities that present individual financial statements on a stand-alone basis to their project lenders.

On June 13, 2003, PCF, a wholly owned stand-alone subsidiary of ours, completed an offering of two tranches of Senior Secured Notes due 2006 and 2010 totaling $802 million original principal amount. The Senior Secured Notes Due 2006 were paid in accordance with their terms upon maturity in 2006 and are no longer outstanding. PCF's 6.256% Senior Secured Notes due 2010 are secured by fixed cash flows from a fixed-priced, long-term PPA with CDWR, pursuant to which PCF sells power to CDWR, and a fixed-priced, long-term PPA with a third party, pursuant to which PCF purchases from the third party the power necessary to fulfill its obligations under the CDWR PPA. The spread between the price for power under the CDWR PPA and the price for power under the third party PPA provides the cash flows to pay debt service on the Senior Secured Notes due 2010 and PCF's other expenses. The Senior Secured Notes due 2010 are non-recourse to us and our other subsidiaries.

PCF has been established as an entity with its existence separate from us and other subsidiaries of ours. PCF's assets and liabilities, consisting of cash (maintained in a debt reserve fund), the third party PPA, the CDWR PPA and the remaining outstanding Senior Secured Notes Due 2010 are separate from our assets and liabilities and those of other subsidiaries of ours. The following table sets forth selected financial information of PCF as of and for the year ended December 31, 2008 (in millions):

	2008
Assets	$ 217
Liabilities	197
Total revenue	515
Total cost of revenue	412
Interest expense	18
Net income	88

See Note 8 of the Notes to Consolidated Financial Statements for further information.

On June 2, 2004, our wholly owned indirect subsidiary, PCF III, issued $85 million aggregate principal amount at maturity of notes collateralized by PCF III's ownership of PCF. PCF III owns all of the equity interests in PCF, the assets of which include a debt reserve fund, which had a balance of approximately $94 million at December 31, 2008 and 2007. We received cash proceeds of approximately $50 million from the issuance of the notes, which accrete in value up to $85 million at maturity in accordance with the accreted value schedule for the notes.

Pursuant to the applicable transaction agreements, PCF III has been established as an entity with its existence separate from Calpine Corporation and other subsidiaries of ours. The following table sets forth the assets and liabilities of PCF III as of December 31, 2008, and does not include the balances of PCF III's subsidiary, PCF (in millions):

	2008
Assets	$ 21
Liabilities	76

See Note 8 of the Notes to Consolidated Financial Statements for further information.

GEC, a wholly owned subsidiary of GEC Holdings, LLC, has been established as an entity with its existence separate from us and other subsidiaries of ours. On September 30, 2003, GEC, a wholly owned subsidiary of our subsidiary GEC Holdings, LLC, completed an offering of $302 million of 4% Senior Secured Notes Due 2011. In connection with the issuance of the secured notes, we received funding on a third party preferred equity investment in GEC Holdings, LLC totaling $74 million. This preferred interest meets the criteria of a mandatorily redeemable financial instrument and has been classified as debt due to certain preferential distributions to the third party. The preferential distributions are due semi-annually beginning in March 2004 through September 2011 and total approximately $113 million over the eight-year period. As of December 31, 2008 and 2007, there was $35 million and $44 million, respectively, outstanding under the preferred interest.

A long-term PPA between CES and CDWR was acquired by GEC by means of a series of capital contributions by CES and certain of its affiliates and is an asset of GEC, and the secured notes and the preferred interest are liabilities of GEC, separate from the assets and liabilities of Calpine Corporation and our other subsidiaries. In addition to the PPA and nine peaker power plants (including Creed and Goose Haven) owned directly or indirectly by GEC, GEC's assets include cash and a 100% equity interest in each of Creed and Goose Haven, each of which is a wholly owned subsidiary of GEC and a guarantor of the 4% Senior Secured Notes Due 2011 issued by GEC. Each of GEC, Creed and Goose Haven has been established as an entity with its existence separate from us and other subsidiaries of ours. Creed and Goose Haven each have assets consisting of a peaker power plant and other assets. The following table sets forth selected financial information of GEC for the year ended December 31, 2008 (in millions):

	2008
Assets	$ 516
Liabilities	134
Total revenue	97
Total cost of revenue	34
Interest expense	9
Net income	53

On December 4, 2003, we announced that we had sold to a group of institutional investors our right to receive payments from PG&E under an agreement between PG&E and Gilroy regarding the termination and buy-out of a Standard Offer contract between PG&E and Gilroy for $133 million in cash. Because the transaction did not satisfy the criteria for sales treatment in accordance with applicable accounting standards it was recorded on our Consolidated Financial Statements as a secured financing, with a note payable of $133 million. The notes receivable balance and note payable balance are both reduced as PG&E makes payments to the buyers of the notes receivable. The $24 million difference between the $157 million book value of the notes receivable at the transaction date and the cash received will be recognized as additional interest expense over the repayment term. We will continue to record interest income over the repayment term, and interest expense will be accreted on the amortizing note payable balance.

Pursuant to the applicable transaction agreements, each of Gilroy and Calpine Gilroy 1, Inc. (the general partner of Gilroy), has been established as an entity with its existence separate from us and other subsidiaries of ours. The following table sets forth the assets and liabilities of Gilroy and Calpine Gilroy I, Inc. as of December 31, 2008 (in millions):

	2008
Assets	$ 409
Liabilities	90

See Notes 6 and 8 of the Notes to Consolidated Financial Statements for further information.

On June 29, 2004, Rocky Mountain Energy Center, LLC and Riverside Energy Center, LLC, wholly owned subsidiaries of our Calpine Riverside Holdings, LLC subsidiary, received funding in the aggregate amount of $661 million comprising $633 million of First Priority Secured Floating Rate Term Loans Due 2011 and a $28 million letter of credit-linked deposit facility.

Pursuant to the applicable transaction agreements, each of Rocky Mountain Energy Center, LLC, Riverside Energy Center, LLC and Calpine Riverside Holdings, LLC has been established as an entity with its existence separate from us. The following table sets forth the assets and liabilities of these entities as of December 31, 2008 (in millions):

	Rocky Mountain Energy Center, LLC 2008	Riverside Energy Center, LLC 2008	Calpine Riverside Holdings, LLC 2008
Assets	$ 388	$ 708	$ 368
Liabilities	178	339	—

See Note 8 of the Notes to Consolidated Financial Statements for further information.

On October 14, 2005, our indirect subsidiary, CCFCP, issued $300 million of six-year redeemable preferred shares. The CCFCP redeemable preferred shares are mandatorily redeemable on the maturity date of October 13, 2011, and are accounted for as long-term debt and any related preferred dividends will be accounted for as interest expense.

The following table sets forth the assets and liabilities of CCFCP as of December 31, 2008 (in millions):

	2008
Assets	$ 2,076
Liabilities	1,157

See Note 8 of the Notes to Consolidated Financial Statements for further information.

In September 2006, we sold a 35% equity interest in Russell City Energy Center, a proposed 600 MW, natural gas-fired power plant to be located in Hayward, California, to ASC for approximately $44 million and ASC's obligation to post a $37 million letter of credit. We own the remaining 65% interest. Construction is anticipated to begin on this project once all permits and other required approvals are final and non-appealable, and project financing has closed.

The following table sets forth the assets and liabilities of Russell City Energy Center as of December 31, 2008 (in millions):

	2008
Assets	$ 91
Liabilities	10

RESULTS OF OPERATIONS FOR THE YEARS ENDED DECEMBER 31, 2008 AND 2007

Below are the results of operations for the year ended December 31, 2008, as compared to the same period in 2007 (in millions, except for percentages and operating performance metrics). In the comparative tables below, increases in revenue/income or decreases in expense (favorable variances) are shown without brackets while decreases in revenue/income or increases in expense (unfavorable variances) are shown with brackets in the "$ Change" and "% Change" columns.

	2008	2007	$ Change	% Change
Operating revenues:				
Commodity revenue	$ 9,648	7,661	$ 1,987	26%
Mark-to-market	232	252	(20)	(8)
Other revenue	57	57	—	—
Operating revenues	9,937	7,970	1,967	25
Cost of revenue:				
Fuel and purchased energy expense:				
Commodity expense	6,938	5,436	(1,502)	(28)
Mark-to-market	343	247	(96)	(39)
Fuel and purchased energy expense	7,281	5,683	(1,598)	(28)
Plant operating expense	918	749	(169)	(23)
Depreciation and amortization expense	433	463	30	6
Operating plant impairments	33	44	11	25
Other cost of revenue	114	136	22	16
Total cost of revenue	8,779	7,075	(1,704)	(24)
Gross profit	1,158	895	263	29
Sales, general and other administrative expense	215	146	(69)	(47)
Loss from unconsolidated investments in power plants	229	21	(208)	#
Other operating expense	26	23	(3)	(13)
Income from operations	688	705	(17)	(2)
Interest expense	1,071	2,019	948	47
Interest (income)	(47)	(64)	(17)	(27)
Minority interest income	(1)	—	1	—
Other (income) expense, net	27	(139)	(166)	#
Loss before reorganization items, income taxes and discontinued operations	(362)	(1,111)	749	67
Reorganization items	(302)	(3,258)	(2,956)	(91)
Income (loss) before income taxes and discontinued operations	(60)	2,147	(2,207)	#
Benefit for income taxes	(47)	(546)	(499)	(91)
Income (loss) before discontinued operations	(13)	2,693	(2,706)	#
Discontinued operations, net of tax provision of $14 in 2008	23	—	23	—
Net income	$ 10	$ 2,693	$ (2,683)	#
Operating Performance Metrics:				
MWh generated (in thousands)(1)	87,762	90,811	(3,049)	(3)
Average availability	90.5%	90.8%	(0.3)	—
Average total MW in operation	23,102	24,755	(1,653)	(7)
Average capacity factor, excluding peakers	47.8%	46.6%	1.2	3
Steam Adjusted Heat Rate	7,231	7,190	(41)	(1)

\# Variance of 100% or greater

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

Commodity revenue, net of commodity expense, increased $485 million for the year ended December 31, 2008, compared to 2007 primarily due to: (i) higher market spark spreads on open positions due to higher natural gas prices throughout the first three quarters of 2008 in our key Texas and West markets which benefited our plants in these regions as they operated more efficiently against corresponding Market Heat Rates, as well as higher Market Heat Rates in the second quarter of 2008, particularly in Texas which resulted from higher temperatures and transmission congestion in the South and Houston zones; (ii) higher realized spark spreads for our generally higher levels of hedging in all regions; and (iii) earnings from settlement of dedesignated hedges, the value for which was previously reflected in OCI. Generation decreased 3% despite a 3% increase in our average capacity factor, excluding peakers, due to a 7%, or 1,653 MW, decrease in our average total MW in operation for the year ended December 31, 2008, compared to 2007. The generation decrease primarily resulted from plant sales in 2007, the deconsolidation and subsequent sale of Auburndale in 2008 and an increase in the number of unscheduled outages in 2008 compared to 2007. Net mark-to-market activity primarily resulting from our portfolio hedging activities that do not qualify for hedge accounting decreased $116 million for the year ended December 31, 2008, compared to 2007.

Plant operating expense increased during the year ended December 31, 2008, compared to the year ended December 31, 2007, primarily as a result of a $92 million increase in expense for major maintenance for scheduled outages related to the life cycle of our plant fleet and an increase of $25 million in plant personnel costs related to stock-based compensation expense for equity awards issued in 2008. The increase in major maintenance is driven by the fact that we placed 23 plants in service in the 2001-2002 time frame and many have reached their 24,000 or 48,000 hour major inspection operating intervals. Routine operating and repair costs also contributed $31 million to the increase in plant operating expense which related to increases in chemical costs and other consumables, and increases in routine repairs. A $16 million increase in expense for outages, many of which occurred in 2007, caused by equipment failures, net of insurance recoveries, also contributed to the increase in plant operating expense for the year ended December 31, 2008, compared to 2007.

Depreciation and amortization expense decreased for the year ended December 31, 2008, compared to the year ended December 31, 2007, primarily due to an upward revision in the estimated useful life of our Geysers Assets in The Geysers region of northern California as well as the sale of Acadia PP in September 2007. The upward revision in the estimated useful life of our Geysers Assets relates to our reservoir replenishment activities which extends the estimated economic life of our Geysers Assets from 2034 to 2050.

Our operating plant impairments for the year ended December 31, 2008, consisted of a $33 million impairment relating to our Auburndale Peaking Energy Center resulting from lower forecasted future cash flows. Operating plant impairments of $44 million during the year ended December 31, 2007, were recorded primarily for the Bethpage Power Plant resulting from the expected adverse impact on power pricing of new power transmission capacity from the PJM market into Long Island.

Other cost of revenue decreased for the year ended December 31, 2008, compared to the year ended December 31, 2007, as a result of an $8 million decrease for the sale of PSM in March 2007, a $10 million decrease in operating lease expense due to the termination of the lease associated with our purchase of the RockGen Energy Center in January 2008 and a decrease of $8 million related to the discontinuation of the amortization of other assets associated with the deconsolidation and subsequent sale of Auburndale in 2008. These decreases were partially offset by a $5 million increase in royalty expense due to higher revenues from our Geysers Assets in 2008 compared to 2007.

Sales, general and other administrative expense was higher for the year ended December 31, 2008, compared to the same period in 2007 due to a $42 million increase in personnel costs resulting primarily from higher stock-based compensation expense arising from the grant of equity awards during the first quarter of 2008 and a $15 million increase in legal and consulting expenses. We also recorded $9 million in additional allowance for doubtful accounts in 2008.

Our loss from unconsolidated investments in power plants increased compared to 2007 primarily due to an impairment charge of $180 million related to our equity interest in Auburndale during the year ended December 31, 2008. See Note 5 of the Notes to Consolidated Financial Statements for further information. We also incurred an increase of $47 million in unrealized mark-to-market losses from an interest rate swap contract related to our investment in OMEC. The increase was partially offset by $9 million in income from our investment in RockGen and an $8 million reduction in losses related to our investment in Greenfield LP for the year ended December 31, 2008, compared to 2007.

Due to the changes in our capital structure on the Effective Date, our interest expense for the years ended December 31, 2008 and 2007, is not comparable. Interest expense decreased primarily due to $376 million in post-petition interest related to pre-emergence debt recorded in 2007, resulting from the Canadian Settlement Agreement as well as $347 million in post-petition interest related to other pre-petition obligations recorded during the year ended December 31, 2007, which was partially offset by $135 million in post-petition interest recorded during the year ended December 31, 2008. In addition, interest expense decreased for the year ended December 31, 2008, compared to the year ended December 31, 2007, due to lower average debt balances and lower average interest rates. During the first quarter of 2008, we settled a portion of our debt through payment of cash and issuance of reorganized Calpine Corporation common stock pursuant to the Plan of Reorganization. Additionally, interest rates on our variable rate debt were lower for the year ended December 31, 2008, compared to 2007, due to a decrease in LIBOR over the same periods. The annualized effective interest rates on our consolidated debt, excluding the impacts of items not directly attributed to the cost of the debt instruments, after amortization of deferred financing costs and debt discounts, were 8.8% and 11.0%, respectively, for the years ended December 31, 2008 and 2007. The decrease was partially offset by $73 million in losses related to our interest rate swaps recorded in 2008 as well as $27 million for settlement obligations related to our Canadian subsidiaries recorded prior to their reconsolidation in February 2008.

Interest income decreased primarily due to lower average cash balances for the year ended December 31, 2008, compared to the same period in 2007 resulting from the distribution of cash pursuant to the Plan of Reorganization in the first quarter of 2008, and due to lower average interest rates.

Other (income) expense, net had an unfavorable variance primarily as a result of the non-recurrence of $135 million in income pertaining to a claim settlement with a customer which received court approval and was recorded during the third quarter of 2007. The claim related to the customer's rejection of our energy services agreement following the customer's bankruptcy filing and was unrelated to our Chapter 11 cases. Also contributing to the decrease was a loss of $13 million incurred during 2008 related to our settlement with Panda, $7 million in refinancing costs related to the refinancing of all outstanding indebtedness under the existing Blue Spruce term loan facility in February 2008 and $6 million for the write-off of unamortized deferred financing costs and other costs associated with the refinancing of our Metcalf term loan facility and preferred interests in June 2008.

The table below lists the significant items within reorganization items for the years ended December 31, 2008 and 2007.

	2008	2007	$ Change	% Change
		(in millions)		
Provision for expected allowed claims	$ (95)	$ (3,687)	$ (3,592)	(97)%
Professional fees	85	217	132	61
Gains on asset sales	(206)	(285)	(79)	(28)
Asset impairments	—	120	120	#
Gain on reconsolidation of Canadian Debtors and other foreign entities	(71)	—	71	—
DIP Facility and Exit Facilities financing and CalGen Secured Debt repayment costs	(4)	202	206	#
Interest (income) on accumulated cash	(7)	(59)	(52)	(88)
Other	(4)	234	238	#
Total reorganization items	$ (302)	$ (3,258)	$ (2,956)	(91)

\# Variance of 100% or greater

Provision for Expected Allowed Claims — During the year ended December 31, 2008, our provision for expected allowed claims consisted primarily of a $62 million credit related to the settlement of claims with the Canadian Debtors, a $12 million credit related to the settlement with Rosetta of our fraudulent conveyance claim and a $34 million credit for RockGen related to a prior period which we determined was not material to any period. During the year ended December 31, 2007, our provision for expected allowed claims consisted primarily of (i) a $4.1 billion credit related to the settlement of claims related to Calpine Corporation's guarantee of the ULC I notes and the release of our guarantee of the ULC II notes following repayment of those notes in September 2007, (ii) accruals totaling $275 million for make whole premiums and/or damages related to the First Priority Notes, Second Priority Debt and Unsecured Notes settlements, (iii) $141 million resulting from the termination of the RockGen operating lease agreement and write-off of the related prepaid lease expense, (iv) $98 million resulting from settlements and repudiation of certain natural gas transportation and PPA contracts, and (v) an additional accrual of $79 million resulting from the rejection of certain leases and other agreements related to the Rumford and Tiverton power plants for which we agreed to allow general unsecured claims in the aggregate of $190 million.

Professional Fees — The decrease in professional fees for the year ended December 31, 2008, over the comparable period in 2007 resulted primarily from a decrease in activity managed by our third party advisors related to our Chapter 11 and CCAA cases.

Gains on Asset Sales — During the year ended December 31, 2008, gains on asset sales primarily resulted from the sales of the Hillabee and Fremont development project assets. See Note 7 of the Notes to Consolidated Financial Statements for further information. During the year ended December 31, 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.

Asset Impairments — During the year ended December 31, 2007, asset impairment charges were primarily due to a pre-tax impairment charge of approximately $89 million to record our interest in Acadia PP at fair value less cost to sell.

Gain on Reconsolidation of Canadian Debtors and Other Foreign Entities — During the year ended December 31, 2008, we recorded a gain of $71 million related to the reconsolidation of our Canadian subsidiaries. See Note 2 of the Notes to Consolidated Financial Statements for further information.

DIP Facility and Exit Facilities Financing and CalGen Secured Debt Repayment Costs — During the year ended December 31, 2008, we recorded a $4 million credit related to a valuation revision for secured shortfall claims related to our Second Priority Debt. During the year ended December 31, 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 Exit Facilities as well as $13 million for secured shortfall claims relating to settlements for the First Priority Notes and the CalGen First Lien Debt during the year ended December 31, 2007.

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

Other — Other reorganization items decreased primarily due to recording a gain of $4 million during the year ended December 31, 2008, versus a loss of $164 million in the year ended December 31, 2007, related to foreign exchange movements on LSTC denominated in a foreign currency and the non-recurrence of a charge of $14 million during the year ended December 31, 2007, resulting from debt pre-payment and make whole premium fees to the project lenders related to the sale of the Aries Power Plant. Also contributing to the decrease was $53 million in emergence incentive cost accruals related to our emergence from Chapter 11 recorded during the year ended December 31, 2007, while no such accruals were recorded in 2008.

For the year ended December 31, 2008, we recorded a tax benefit of $47 million before discontinued operations compared to a benefit of $546 million for the year ended December 31, 2007. Because of valuation allowances recorded against certain deferred tax assets, our effective tax differs considerably from an expected rate. Our tax structure is comprised primarily of two taxable groups, CCFC and its subsidiaries and Calpine Corporation and its subsidiaries other than CCFC. CCFC and its subsidiaries no longer have a valuation allowance recorded against its deferred tax assets due to its ability to generate sufficient income to utilize its NOLs. Our 2008 benefit for income taxes before discontinued operations primarily relates to a foreign tax benefit of $70 million recorded as a result of the Canadian Settlement Agreement, and a tax benefit allocation of $90 million due to intraperiod allocation, under SFAS No. 109, of a $76 million tax benefit to continuing operations due to current OCI gains and a $14 million tax benefit in income from discontinued operations, offset by tax expense of approximately $100 million on CCFC's income. Our 2007 benefit for income taxes consisting primarily of $485 million related to the release of valuation allowance in 2007. See Note 9 of the Notes to Consolidated Financial Statements for further information.

During the year ended December 31, 2008, we recorded $23 million in discontinued operations, net of taxes of $14 million, related to the settlement with Rosetta of all of our outstanding claims related to our domestic oil and gas assets we sold to Rosetta for $1.1 billion in 2005. See Note 7 of the Notes to Consolidated Financial Statements for further information.

RESULTS OF OPERATIONS FOR THE YEARS ENDED DECEMBER 31, 2007 AND 2006

Below are the results of operations for the year ended December 31, 2007, as compared to the same period in 2006 (in millions, except for percentages and operating performance metrics). In the comparative tables below, increases in revenue/income or decreases in expense (favorable variances) are shown without brackets while decreases in revenue/income or increases in expense (unfavorable variances) are shown with brackets in the "$ Change" and "% Change" columns.

	2007	2006	$ Change	% Change
Operating revenues:				
Commodity revenue	$ 7,661	$ 6,533	$ 1,128	17%
Mark-to-market	252	331	(79)	(24)
Other revenue	57	73	(16)	(22)
Operating revenues	7,970	6,937	1,033	15
Cost of revenue:				
Fuel and purchased energy expense:				
Commodity expense	5,436	4,512	(924)	(20)
Mark-to-market	247	240	(7)	(3)
Fuel and purchased energy expense	5,683	4,752	(931)	(20)
Plant operating expense	749	750	1	—
Depreciation and amortization expense	463	470	7	1
Operating plant impairments	44	53	9	17
Other cost of revenue	136	172	36	21
Total cost of revenue	7,075	6,197	(878)	(14)
Gross profit	895	740	155	21
Sales, general and other administrative expense	146	175	29	17
Loss from unconsolidated investments in power plants	21	—	(21)	—
Other operating expense	23	101	78	77
Income from operations	705	464	241	52
Interest expense	2,019	1,254	(765)	(61)
Interest (income)	(64)	(79)	(15)	(19)
Minority interest expense	—	5	5	#
Other (income) expense, net	(139)	13	152	#
Loss before reorganization items and income taxes	(1,111)	(729)	(382)	(52)
Reorganization items	(3,258)	972	4,230	#
Income (loss) before income taxes	2,147	(1,701)	3,848	#
(Benefit) provision for income taxes	(546)	64	610	#
Net income (loss)	$ 2,693	$ (1,765)	$ 4,458	#
Operating Performance Metrics:				
MWh generated (in thousands)(1)	90,811	83,146	7,665	9
Average availability	90.8%	91.3%	(0.5)	(1)
Average total MW in operation	24,755	26,785	(2,030)	(8)
Average capacity factor, excluding peakers	46.6%	39.2%	7.4	19
Steam Adjusted Heat Rate	7,190	7,223	33	—

\# Variance of 100% or greater

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

Commodity revenue, net of commodity expense, increased $204 million for the year ended December 31, 2007, compared to 2006 resulting from higher market spark spreads on open positions, particularly in the West and Southeast, in 2007 due to higher temperatures and drought conditions which led to increased demand. Also contributing to the increase in 2007 compared to 2006 was unseasonably high rainfall in the first half of 2006 in the Pacific Northwest, which led to increased hydroelectric production, and, correspondingly, dampened demand for natural gas-fired generation in the West during the same period. The increase was partially offset by lower market spark spreads on open positions in Texas due to higher than average rainfall in the summer of 2007 which led to decreased demand. Generation increased 9% despite an 8%, or 2,030 MW, decrease in our average total MW in operation for the year ended December 31, 2007, compared to 2006, primarily resulting from plant sales in 2007 and 2006. Net mark-to-market activity primarily resulting from our portfolio hedging activities that do not qualify for hedge accounting decreased $86 million for the year ended December 31, 2007, compared to 2006. Other revenue decreased $16 million primarily due to a decrease in revenue related to the sale of PSM in March 2007.

Operating plant impairments of $44 million during the year ended December 31, 2007, were recorded primarily for the Bethpage Power Plant resulting from the expected adverse impact on power pricing of new power transmission capacity from the PJM market into Long Island. Our operating plant impairments for the year ended December 31, 2006, consisted primarily of a $50 million impairment relating to Fox Energy Center. Certain impairment charges related to our restructuring activities were also recorded during the year ended December 31, 2007, as reorganization items as discussed below.

Other cost of revenue decreased for the year ended December 31, 2007, compared to the year ended December 31, 2006, resulting primarily from lower operating lease expense and lower cost of revenue at PSM, which was sold in March of 2007.

Sales, general and other administrative expense decreased for the year ended December 31, 2007, compared to the year ended December 31, 2006, primarily due to an $11 million net reduction in personnel costs resulting from lower headcount and the sale of PSM in early 2007 as well as lower professional fees and consulting fees of $10 million.

Other operating expense decreased primarily due to the non-recurrence of $65 million in impairment charges recorded for the year ended December 31, 2006, related to certain turbine-generator equipment not assigned to projects for which we determined near-term sales were likely. During the year ended December 31, 2007, an additional $2 million in impairments were recorded related to these turbines resulting from reduced estimated sales prices.

Interest expense increased for the year ended December 31, 2007, compared to the year ended December 31, 2006, primarily due to $376 million in post-petition interest related to the ULC I notes resulting from the Canadian Settlement Agreement and $347 million in post-petition interest related to other pre-petition obligations recorded during the year ended December 31, 2007, while no similar expense was recorded in the prior year. We also recorded $126 million in default interest in late 2007 related to various settlements reached as well as expected allowed claims for default interest on the CalGen Second Lien Debt and CalGen Third Lien Debt. This was partially offset by the net effect of the refinancings of the CalGen Secured Debt and the Original DIP Facility in late March 2007 primarily using proceeds under the DIP Facility, which carried lower interest rates, and by the repayment of the First Priority Notes in May and June of 2006 using restricted cash and funds available under the Original DIP Facility, which also carried lower interest rates. The total increase in interest expense was also partially offset by a $43 million decrease due to the extinguishment of certain project financing debt as a result of our asset sales, principally related to the Fox Energy Center and Aries Power Plant.

Other (income) expense, net increased for the year ended December 31, 2007, compared to the year ended December 31, 2006, primarily as a result of $135 million in income pertaining to a claim settlement with a customer which received court approval during the year ended December 31, 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, which was unrelated to our Chapter 11 cases.

The table below lists the significant items within reorganization items for the years ended December 31, 2007 and 2006.

	2007	2006	$ Change	% Change
	(in millions)			
Provision for expected allowed claims	$ (3,687)	$ 845	$ 4,532	#%
Professional fees	217	153	(64)	(42)
Gains on asset sales	(285)	(106)	179	#
Asset impairments	120	—	(120)	—
DIP Facility and Exit Facilities financing and CalGen Secured Debt repayment costs	202	39	(163)	#
Interest (income) on accumulated cash	(59)	(25)	34	#
Other	234	66	(168)	#
Total reorganization items	$ (3,258)	$ 972	$ 4,230	#

\# Variance of 100% or greater

Provision for Expected Allowed Claims — During the year ended December 31, 2007, our provision for expected allowed claims consisted primarily of (i) a $4.1 billion credit related to the settlement of claims related to Calpine Corporation's guarantee of the ULC I notes and the release of our guarantee of the ULC II notes following repayment of those notes in September 2007, (ii) accruals totaling $275 million for make whole premiums and/or damages related to the First Priority Notes, Second Priority Debt and Unsecured Notes settlements, (iii) $141 million resulting from the termination of the RockGen operating lease agreement and write-off of the related prepaid lease expense, (iv) $98 million resulting from settlements and repudiation of certain gas transportation and PPA contracts, and (v) an additional accrual of $79 million resulting from the rejection of certain leases and other agreements related to the Rumford and Tiverton power plants for which we agreed to allow general unsecured claims in the aggregate of $190 million. During the year ended December 31, 2006, our provision for expected allowed claims related primarily to repudiated natural gas transportation and power transmission contracts, the rejection of the Rumford and Tiverton power plant leases and the write-off of prepaid lease expense and certain fees and expenses related to the transaction.

Professional Fees — The increase in professional fees for the year ended December 31, 2007, over the comparable period in 2006 resulted primarily from an increase in activity managed by our third party advisors related to our Plan of Reorganization, litigation and claims reconciliation matters.

Gains on Asset Sales — During the year ended December 31, 2007, gains on asset sales primarily resulted from the sales of the Aries Power Plant, Goldendale Energy Center, PSM and Parlin Power Plant. During the year ended December 31, 2006, gains on asset sales primarily resulted from the sale of the Dighton Power Plant and Fox Energy Center. See Note 7 of the Notes to Consolidated Financial Statements for further information.

Asset Impairments — During the year ended December 31, 2007, asset impairment charges consisted primarily of a pre-tax 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 7 of the Notes to Consolidated Financial Statements for further information.

DIP Facility and Exit Facilities Financing and CalGen Secured Debt Repayment Costs — During the year ended December 31, 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. During the year ended December 31, 2007, we also recorded transaction costs of $22 million related to the execution of a commitment letter to fund our Exit Facilities as well as $13 million for secured shortfall claims relating to settlements for the First Priority Notes and the CalGen First Lien Debt. See Note 8 of the Notes to Consolidated Financial Statements for further information.

Other — Other reorganization items increased primarily due to a $156 million increase in foreign exchange losses on LSTC denominated in a foreign currency over the comparable period in the prior year.

For the year ended December 31, 2007, we recorded a tax benefit of approximately $546 million consisting primarily of $485 million related to the release of valuation allowance compared to recording tax expense of $64 million for the year ended December 31, 2006, which primarily related to recording valuation allowances against our deferred tax assets. See Note 9 of the Notes to Consolidated Financial Statements for further information regarding our income taxes.

COMMODITY MARGIN AND ADJUSTED EBITDA

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

Commodity Margin by Segment for the Years Ended December 31, 2008 and 2007

We use the non-GAAP financial measure "Commodity Margin" to assess our financial performance by our reportable segments. Commodity Margin includes our power and steam revenues, marketing, hedging and optimization activities, REC revenue, transmission revenue and expenses, and fuel and purchased energy expense, but excludes net commodity mark-to-market activity and other service revenues. We believe that Commodity Margin is a useful tool for assessing the performance of our core operations and is a key operational measure reviewed by our chief operating decision maker. Commodity Margin is not a measure calculated in accordance with GAAP, and should be viewed as a supplement to and not a substitute for our results of operations presented in accordance with GAAP. Commodity Margin does not intend to represent gross profit (loss), the most comparable GAAP measure, as an indicator of operating performance and is not necessarily comparable to similarly-titled measures reported by other companies. See Note 17 of the Notes to Consolidated Financial Statements for a reconciliation of Commodity Margin to gross profit (loss) by segment.

The following tables show our Commodity Margin and related operating performance metrics by segment for the years ended December 31, 2008 and 2007. In the comparative tables below, favorable variances are shown without brackets while unfavorable variances are shown with brackets in the "Change" and "% Change" columns.

West:	2008	2007	Change	% Change
Commodity Margin (in millions)	$ 1,191	$ 1,196	$ (5)	—%
Commodity Margin per MWh generated	$ 32.07	$ 32.47	$ (0.40)	(1)
MWh generated (in thousands)	37,137	36,837	300	1
Average availability	89.1%	90.8%	(1.7)	(2)
Average total MW in operation	7,246	7,281	(35)	—
Average capacity factor, excluding peakers	66.1%	65.3%	0.8	1
Steam Adjusted Heat Rate	7,267	7,336	69	1

West — Commodity Margin in our West segment decreased by $5 million for the year ended December 31, 2008, compared to the year ended December 31, 2007. The decrease resulted primarily from lower realized margins in the fourth quarter of 2008 as compared to 2007 and a negative year on year variance associated with natural gas storage inventory. In 2008, we recorded a loss on natural gas storage resulting from the decrease in market natural gas prices in late summer through the fourth quarter of 2008, while in the fourth quarter of 2007 we recognized a positive impact from sales of natural gas storage inventory. The decrease was partially offset by a 1% increase both in generation and improvement in our Steam Adjusted Heat Rate during the year ended December 31, 2008, compared to 2007, higher on peak market spark spreads from higher natural gas prices in the second quarter of 2008, and the favorable impact of new and renegotiated power contracts.

Texas:	2008	2007	Change	% Change
Commodity Margin (in millions)	$ 815	$ 500	$ 315	63%
Commodity Margin per MWh generated	$ 25.15	$ 15.08	$ 10.07	67
MWh generated (in thousands)	32,408	33,154	(746)	(2)
Average availability	88.8%	90.8%	(2.0)	(2)
Average total MW in operation	7,251	7,266	(15)	—
Average capacity factor, excluding peakers	50.9%	52.1%	(1.2)	(2)
Steam Adjusted Heat Rate	7,082	6,830	(252)	(4)

Texas — Commodity Margin in our Texas segment increased by $315 million, or 63%, for the year ended December 31, 2008, compared to 2007, due primarily to higher market spark spreads driven by higher natural gas prices during the second and third quarters of 2008 and transmission congestion in the South and Houston zones in the second quarter of 2008. Also positively impacting Commodity Margin were higher realized spark spreads on hedged positions in the fourth quarter of 2008 despite lower market spark spreads during the same period. Market spark spreads decreased in September 2008 as compared to the same period in 2007 due to the impact of Hurricane Ike; however, we were able to purchase replacement power at prices below our generation cost and hedged prices during the same period, which had a favorable impact in September 2008. Generation in our Texas segment decreased by 2% due to an increase in planned outages for major maintenance and milder weather which led to decreased demand for the year ended December 31, 2008, compared to the year ended December 31, 2007. We experienced a 4% increase in our Steam Adjusted Heat Rate for the year ended December 31, 2008, compared to 2007 resulting from the loss of steam load due to the impact of Hurricane Ike, an extended outage at our Baytown Power Plant in the first and second quarters of 2008 and lower steam demand from our customers during the second half of 2008.

Southeast:	2008	2007	Change	% Change
Commodity Margin (in millions)	$ 300	$ 268	$ 32	12%
Commodity Margin per MWh generated	$ 23.40	$ 18.11	$ 5.29	29
MWh generated (in thousands)	12,820	14,795	(1,975)	(13)
Average availability	93.6%	92.1%	1.5	2
Average total MW in operation	6,204	7,222	(1,018)	(14)
Average capacity factor, excluding peakers	26.5%	25.5%	1.0	4
Steam Adjusted Heat Rate	7,388	7,544	156	2

Southeast — Commodity Margin in our Southeast segment increased by $32 million, or 12%, for the year ended December 31, 2008, compared to the year ended December 31, 2007, resulting from the impact of more favorable pricing on our hedged volumes and the favorable impact of new power contracts. In addition, we recognized $21 million of Commodity Margin during the second quarter of 2008 related to a transmission capacity contract for which we received approval from FERC during the second quarter of 2008. The increase was partially offset by a decrease in market spark spreads on open positions for the year ended December 31, 2008, compared to 2007. We experienced a 4% increase in our average capacity factor, excluding peakers, and 2% increase in our average availability for the year ended December 31, 2008, compared to 2007. Despite higher availability, generation decreased 13% due to a 14%, or 1,018 MW, decrease in our average total MW in operation following the sale of our interest in Acadia PP in 2007, the sale of Auburndale in 2008 and an unplanned outage at our Carville Power Plant due to Hurricane Gustav during the third quarter of 2008.

North:	2008	2007	Change	% Change
Commodity Margin (in millions)	$ 280	$ 283	$ (3)	(1)%
Commodity Margin per MWh generated	$ 51.88	$ 46.97	$ 4.91	10
MWh generated (in thousands)	5,397	6,025	(628)	(10)
Average availability	92.6%	87.4%	5.2	6
Average total MW in operation	2,401	2,986	(585)	(20)
Average capacity factor, excluding peakers	33.7%	33.6%	0.1	—
Steam Adjusted Heat Rate	7,584	7,646	62	1

North — Commodity Margin in our North segment decreased by $3 million resulting from lower realized spark spreads during the fourth quarter of 2008 compared to the same period in 2007 and the deconsolidation of RockGen in January 2008. This was partially offset by higher hedged levels at more favorable pricing during the third quarter of 2008 compared to the same period in 2007. Generation in the North decreased 10% due primarily to lower generation at power plants whose generation is contracted and controlled by third parties and outages at our Westbrook Power Plant during the second quarter of 2008.

Other:	2008	2007	Change	% Change
Commodity Margin (in millions)	$ 124	$ (22)	$ 146	#%

\# Variance of 100% or greater

Other — Commodity Margin in our Other segment increased by $146 million resulting from the settlement of dedesignated hedges, the value for which was previously reflected in OCI.

Commodity Margin by Segment for the Years Ended December 31, 2007 and 2006

The following tables show our Commodity Margin and related operating performance metrics by segment for years ended December 31, 2007 and 2006. In the comparative tables below, favorable variances are shown without brackets while unfavorable variances are shown with brackets in the "Change" and "% Change" columns.

West:	2007	2006	Change	% Change
Commodity Margin (in millions)	$ 1,196	$ 1,037	$ 159	15%
Commodity Margin per MWh generated	$ 32.47	$ 30.00	$ 2.47	8
MWh generated (in thousands)	36,837	34,567	2,270	7
Average availability	90.8%	91.6%	(0.8)	(1)
Average total MW in operation	7,281	7,608	(327)	(4)
Average capacity factor, excluding peakers	65.3%	58.7%	6.6	11
Steam Adjusted Heat Rate	7,336	7,321	(15)	—

West — Commodity Margin in our West segment increased by 15% for the year ended December 31, 2007, compared to the same period a year ago, partially resulting from a 7% increase in generation in spite of a 4% decrease in our average total MW in operation, which was largely due to the sale of the Goldendale Energy Center in February 2007. The increase in generation largely resulted from increased hydroelectric production in 2006 and warmer temperatures in 2007 despite a 1% decrease in our average availability in 2007 compared to 2006. Our average capacity factor, excluding peakers, increased in the West segment to 65.3% in 2007 from 58.7% in 2006. Open market spark spreads were higher in 2007 as our West segment experienced warmer temperatures in 2007 compared to 2006. Additionally, in the first half of 2006 there was unseasonably high rainfall in the Pacific Northwest, which led to increased hydroelectric production, which, correspondingly, dampened demand for natural gas-fired generation. Our geothermal Commodity Margin also increased, benefiting from higher average power prices in 2007 and the restructuring of a renewable energy contract.

Texas:	2007	2006	Change	% Change
Commodity Margin (in millions)	$ 500	$ 477	$ 23	5%
Commodity Margin per MWh generated	$ 15.08	$ 17.56	$ (2.48)	(14)
MWh generated (in thousands)	33,154	27,169	5,985	22
Average availability	90.8%	88.6%	2.2	2
Average total MW in operation	7,266	7,430	(164)	(2)
Average capacity factor, excluding peakers	52.1%	41.7%	10.4	25
Steam Adjusted Heat Rate	6,830	6,878	48	1

Texas — Commodity Margin in our Texas segment increased by 5% as we experienced a 22% increase in generation for the year ended December 31, 2007, compared to 2006 resulting from increased demand due to higher temperatures in the first half of 2007. The increase in Commodity Margin was partially offset by lower average open market spark spreads in July and August of 2007 due to higher than average rainfall in Texas which led to decreased demand compared to the same periods in 2006. Our average capacity factor, excluding peakers, increased in 2007 to 52.1% from 41.7% in 2006, primarily due to the higher demand and the higher average availability in 2007 compared to 2006.

Southeast:	2007	2006	Change	% Change
Commodity Margin (in millions)	$ 268	$ 215	$ 53	25%
Commodity Margin per MWh generated	$ 18.11	$ 15.41	$ 2.70	18
MWh generated (in thousands)	14,795	13,954	841	6
Average availability	92.1%	92.6%	(0.5)	(1)
Average total MW in operation	7,222	8,184	(962)	(12)
Average capacity factor, excluding peakers	25.5%	20.9%	4.6	22
Steam Adjusted Heat Rate	7,544	7,579	35	—

Southeast — Commodity Margin in our Southeast segment increased 25% for the year ended December 31, 2007, compared to the same period in the prior year. The increase can be partially attributed to a 6% increase in generation in 2007 compared to 2006 resulting from warmer temperatures and drought conditions, particularly in the third quarter, which led to increased demand and more favorable pricing conditions. The increased generation occurred although we had a 12% decrease in average total MW in operation in 2007 compared to 2006 due to the sale of our Aries Power Plant in January 2007 and Acadia Energy Center in September 2007. Our average capacity factor, excluding peakers, increased to 25.5% in 2007 from 20.9% in 2006. The increase in Commodity Margin was also the result of higher average open market spark spreads and higher capacity revenues in 2007.

North:	2007	2006	Change	% Change
Commodity Margin (in millions)	$ 283	$ 313	$ (30)	(10)%
Commodity Margin per MWh generated	$ 46.97	$ 41.98	$ 4.99	12
MWh generated (in thousands)	6,025	7,456	(1,431)	(19)
Average availability	87.4%	93.7%	(6.3)	(7)
Average total MW in operation	2,986	3,563	(577)	(16)
Average capacity factor, excluding peakers	33.6%	32.3%	1.3	4
Steam Adjusted Heat Rate	7,646	7,486	(160)	(2)

North — Commodity Margin in our North segment decreased by 10% in 2007 compared to 2006 primarily due to a 19% decrease in generation as our average total MW in operation and average availability decreased by 16% and 7%, respectively, for the year ended December 31, 2007, compared to the same period in the prior year. The decrease in total MW in operation resulted from the sale of our Dighton Power Plant in October 2006 and our Parlin Power Plant in July 2007 as well as the rejection of the Rumford and Tiverton power plant operating leases in June 2006. The sale or disposition of these assets also led to a reduction in capacity revenues in 2007.

Other:	2007	2006	Change	% Change
Commodity Margin (in millions)	$ (22)	$ (21)	$ (1)	(5)%

\# Variance of 100% or greater

Adjusted EBITDA

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

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

Additionally, we believe that investors commonly adjust EBITDA information to eliminate the effect of restructuring and other expenses, which vary widely from company to company and impair comparability. As we define it, Adjusted EBITDA excludes the impact of reorganization items and impairment charges, among other items as detailed in the below reconciliation. We have recognized substantial reorganization items, both direct and incremental, in connection with our Chapter 11 cases as well as substantial asset impairment charges related to our Chapter 11 filings and actions we have taken with respect to our portfolio of assets in connection with our reorganization efforts. Our reorganization items have decreased significantly since our emergence date and only include income and expenses specific to events as part of our reorganization such as our reconsolidation of our Canadian and other foreign subsidiaries, the planned sales of Fremont and Hillabee development projects and our settlement with Rosetta. We do not expect significant reorganization items in 2009. Therefore, we exclude reorganization items and impairment charges from Adjusted EBITDA as our management believes that these items would distort their ability to efficiently view and assess our core operating trends.

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

The table below provides a reconciliation of Adjusted EBITDA to our GAAP net income for the years ended December 31, 2008, 2007 and 2006 (in millions):

	2008	2007[1]	2006[1]
GAAP net income (loss)	$ 10	$ 2,693	$ (1,765)
Less: Income from discontinued operations	23	—	—
Net income (loss) from continuing operations	(13)	2,693	(1,765)
Add:			
Adjustments to reconcile GAAP net income (loss) to Adjusted EBITDA:			
Interest expense, net of interest income	1,024	1,955	1,175
Depreciation and amortization expense, excluding deferred financing costs[2]	467	507	522
(Benefit) provision for income taxes	(47)	(546)	64
Impairment charges	226	46	118
Reorganization items	(302)	(3,258)	972
Major maintenance expense	190	98	77
Operating lease expense	46	54	66
Non-cash gains on derivatives[3]	(40)	(53)	(12)
Unrealized (gains) losses on commodity derivative mark-to-market activity	(35)	35	(201)
Adjustments to reflect Adjusted EBITDA from unconsolidated investments[4][5]	76	20	—
Claim settlement income	—	(135)	—
Stock-based compensation expense (income)	50	(1)	5
Non-cash loss on dispositions of assets	34	33	39
Non-cash gain (loss) on repurchase or extinguishment of debt	13	(1)	18
Other	10	(2)	(10)
Adjusted EBITDA	$ 1,699	$ 1,445	$ 1,068

(1) 2007 and 2006 Adjusted EBITDA as previously reported has been recast to conform to our current year definition.

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

(3) Includes realized and unrealized non-cash gains and losses on derivatives that do not qualify for hedge accounting.

(4) Recorded on our Consolidated Statements of Operations in loss from unconsolidated investments in power plants.

(5) Adjustments to reflect Adjusted EBITDA from unconsolidated investments include $57 million and $20 million in unrealized losses on mark-to-market activity for the years ended December 31, 2008 and 2007, respectively.

RISK MANAGEMENT AND COMMODITY ACCOUNTING

We actively manage the commodity risks of our portfolio, utilizing multiple strategies of buying and selling power or natural gas to manage our spark spread, or selling Heat Rate transactions into the market, which results in a long commodity position. When the Market Heat Rate exceeds the cost for our plants to convert natural gas into power, we realize the long Heat Rate position.

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

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

We economically hedge a substantial portion of our generation and natural gas portfolio mostly through power and gas forward transactions. By entering into these transactions, we are able to economically hedge a portion of our spark spread at pre-determined generation and price levels. We utilize a combination of PPAs and other hedging instruments to manage our variability in future cash flows. As of December 31, 2008, the maximum length of our PPAs was 24 years into the future and the maximum length of time over which we were hedging using commodity and interest rate derivative instruments was 4 and 18 years, respectively. We currently estimate that pre-tax gains of $163 million would be reclassified from AOCI into earnings during the year ending December 31, 2009, as the hedged transactions affect earnings assuming constant natural gas and power prices and interest rates over time; however, the actual amounts that will be reclassified will likely vary based on changes in natural gas and power prices as well as interest rates. Therefore, management is unable to predict what the actual reclassification from AOCI to earnings (positive or negative) will be for the next twelve months.

Derivatives — We enter into a variety of derivative instruments such as exchange traded and OTC power and natural gas forwards, options and interest rate swaps. Derivative contracts are measured at their fair value and recorded as either assets or liabilities unless exempted from derivative treatment as a normal purchase and normal sale. All changes in the fair value of contracts accounted for as derivatives are recognized currently in earnings (as a component of our operating revenues, fuel and purchased energy expense, or interest expense) unless specific hedge criteria are met. The hedge criteria requires us to formally document, designate and assess the effectiveness of transactions that receive hedge accounting. Effective January 1, 2008, we adopted SFAS No. 157, which provides a framework for measuring fair value under GAAP and, among other things, requires enhanced disclosures about assets and liabilities carried at fair value. As of December 31, 2008, our level 3 derivative assets and liabilities represent approximately 0.8% and 0.3% of our total assets and total liabilities, respectively. The actual amounts that will ultimately be settled will likely vary based on changes in natural gas prices and power prices as well as changes in interest rates. Such variances could be material. See Note 10 of the Notes to Consolidated Financial Statements for further discussion related to the adoption of this standard.

The primary factors affecting our market risk and the fair value of our derivatives at any point in time are the volume of open derivative positions (MMBtu and MWh), changing commodity market prices, principally for power and natural gas, liquidity risk, price volatility, counterparty credit risk and changes in interest rates. In that prices for power and natural gas are among the most volatile of all commodity prices, there may be material changes in the fair value of our derivatives over time, driven both by price volatility and the changes in volume of open derivative transactions. Significant volatility in both natural gas and power prices as well as increased hedging and optimization activities during 2008 have had a significant impact on the presentation of our derivative assets and liabilities. Our derivative assets and liabilities have increased to $4.0 billion and $(4.5) billion at December 31, 2008, compared to $1.0 billion and $(1.4) billion at December 31, 2007, respectively. There is a substantial amount of volatility inherent in accounting for the fair value of these derivatives, and our results during the years ended December 31, 2008 and 2007 have reflected this as discussed below.

The change in fair value of our outstanding commodity and interest rate swap derivative instruments from January 1, 2008, through December 31, 2008, is summarized in the table below (in millions):

	Interest Rate Swaps	Commodity Instruments	Total
Fair value of contracts outstanding at January 1, 2008[1]	$ (169)	$ (216)	$ (385)
(Gains) losses recognized or otherwise settled during the period[2]	67	(51)	16
Fair value attributable to new contracts	23	(332)	(309)
Changes in fair value attributable to price movements	(452)	611	159
Change in fair value attributable to adoption of SFAS No. 157	79	—	79
Fair value of contracts outstanding at December 31, 2008[3]	$ (452)	$ 12	$ (440)

(1) Reflects our portfolio of derivative assets and liabilities adjusted for the day one loss of $(22) million, excluding the tax benefit of $8 million, recognized upon adoption of SFAS No. 157 on January 1, 2008.

(2) Commodity settlements consist of (i) recognized gains from commodity cash flow hedges of $68 million, (ii) losses related to deferred items of $(40) million and (iii) gains related to undesignated derivatives of $23 million (represents a portion of operating revenues and fuel and purchased energy expense as reported on our Consolidated Statements of Operations).

(3) Net commodity and interest rate swap derivative assets (liabilities) reported in Notes 10 and 11 of the Notes to Consolidated Financial Statements.

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

The table below details the components of our total mark-to-market activity and where they are recorded on our Consolidated Statements of Operations for the years ended December 31, 2008, 2007 and 2006 (in millions):

	2008	2007	2006
Power contracts included in operating revenues	$ 232	$ 252	$ 331
Natural gas contracts included in fuel and purchased energy expense	(343)	(247)	(240)
Interest rate swaps included in interest expense	(22)	(18)	8
Total mark-to-market activity	$ (133)	$ (13)	$ 99

The components of our total mark-to-market gain (loss) for our commodity instruments and interest rate swaps for the years ended December 31, 2008, 2007 and 2006 are outlined below (in millions):

	2008	2007	2006
Realized gain (loss)(1)	$ (157)	$ 39	$ (110)
Unrealized gain (loss)	24	(52)	209
Total mark-to-market gain (loss)	$ (133)	$ (13)	$ 99

(1) Balance includes a non-cash gain from amortization of prepaid power sales agreements of approximately $40 million, $54 million and $34 million for the years ended December 31, 2008, 2007 and 2006, respectively.

Our change in AOCI from an accumulated loss of $(231) million at December 31, 2007, to an accumulated loss of $(158) million at December 31, 2008, was primarily driven by an increase in power prices on commodity hedges partially offset by a decrease in interest rates on interest rate swap derivatives.

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

The fair value of outstanding derivative commodity instruments at December 31, 2008, based on price source and the period during which the instruments will mature, are summarized in the table below (in millions):

Fair Value Source	2009	2010-2011	2012-2013	After 2013	Total
Prices actively quoted	$ 389	$ 255	$ (7)	$ —	$ 637
Prices provided by other external sources	(358)	(289)	19	—	(628)
Prices based on models and other valuation methods	3	—	(1)	1	3
Total fair value	$ 34	$ (34)	$ 11	$ 1	$ 12

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

The table below presents the high, low and average of our daily VAR for the year ended December 31, 2008, as well as our VAR at December 31, 2008 (in millions):

	2008
Year ended December 31:	
High	$ 70
Low	$ 29
Average	$ 49
As of December 31	$ 45

Liquidity Risk — Liquidity risk arises from the general funding requirements needed to manage our activities and assets and liabilities. Increasing natural gas prices or Market Heat Rates can cause increased collateral requirements. Our liquidity management framework is intended to maximize liquidity access and minimize funding costs during times of rising prices. See further discussion regarding our uses of collateral as they relate to our commodity procurement and risk management activities in Note 11 of the Notes to Consolidated Financial Statements.

We have also entered into the 12-month Knock-in Facility and Commodity Collateral Revolver and borrowed $725 million under our Exit Credit Facility, as discussed in "— Liquidity and Capital Resources" above to mitigate our liquidity risk.

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

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

We believe that our credit policies adequately monitor and diversify our credit risk. We currently have no individual significant concentrations of credit risk to a single counterparty; however a series of defaults or events of nonperformance by several of our individual counterparties caused by a prolonged market recession could impact our liquidity and future results of operations. We monitor and manage our total comprehensive credit risk associated with all of our contracts and PPAs irrespective of whether they are accounted for as a normal purchase normal sale or whether they are marked-to-market and included in our derivative assets and liabilities on our Consolidated Balance Sheets. Our counterparty credit quality associated with the net fair value of outstanding derivative commodity instruments is included in our derivative assets and liabilities at December 31, 2008, and the period during which the instruments will mature are summarized in the table below (in millions):

Credit Quality (Based on Standard & Poor's Ratings as of December 31, 2008)	2009	2010-2011	2012-2013	After 2013	Total
Investment grade	$ 33	$ (33)	$ 12	$ —	$ 12
Non-investment grade	—	—	—	—	—
No external ratings	1	(1)	(1)	1	—
Total fair value	$ 34	$ (34)	$ 11	$ 1	$ 12

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

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

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

Currently, we use interest rate swaps to adjust the mix between fixed and floating rate debt as a hedge of our interest rate risk. We do not use interest rate derivative instruments for trading purposes. In order to manage our risk to significant increases in LIBOR, we have effectively hedged $7.0 billion of our variable rate debt through December 31, 2010, through the use of variable to fixed interest rate swaps. The majority of our interest rate swaps mature in years 2009 through 2012. See the table below for additional illustration of our interest rate swaps. To the extent eligible, our interest rate swaps have been designed as cash flow hedges, and changes in fair value are recorded in OCI to the extent they are effective.

The following table summarizes the contract terms as well as the fair values of our significant financial instruments exposed to interest rate risk as of December 31, 2008. All outstanding balances and fair market values are shown gross of applicable premium or discount, if any (in millions):

	2009	2010	2011	2012	2013	Thereafter	Total	Fair Value December 31, 2008
Debt by Maturity Date:								
Fixed Rate	$ 176	$ 207	$ 71	$ 21	$ 24	$ 128	$ 627	$ 593
Average Interest Rate	6.1%	6.5%	6.9%	9.6%	9.6%	7.4%		
Variable Rate	$ 507	$ 182	$ 1,709	$ 75	$ 76	$ 6,577	$ 9,126	$ 7,086
Average Interest Rate	6.7%	4.1%	7.0%	4.5%	4.7%	5.5%		
Interest Rate Derivative Instruments (Notional Value):								
Variable to Fixed Swaps	$ 6,892	$ 7,007	$ 4,619	$ 4,244	$ 177	$ 125	n/a	$ (452)
Average Pay Rate	4.4%	4.4%	4.4%	4.7%	4.2%	4.2%		
Average Receive Rate	1.6%	1.5%	1.8%	2.0%	2.1%	2.3%		

APPLICATION OF CRITICAL ACCOUNTING POLICIES

The preparation of financial statements in accordance with GAAP requires management to make certain estimates and assumptions which are inherently imprecise and may differ significantly from actual results achieved. We believe the following are our more critical accounting policies due to the significance, subjectivity and judgment involved in determining our estimates used in preparing our Consolidated Financial Statements. See Note 2 of the Notes to Consolidated Financial Statements for a discussion of the application of these and other accounting policies. We evaluate our estimates and assumptions used in preparing our Consolidated Financial Statements on an ongoing basis utilizing historic experience, anticipated future events or trends, consultation with third party advisors or other methods that involve judgment as determined appropriate under the circumstances. The resulting effects of changes in our estimates are recorded in our Consolidated Financial Statements in the period in which the facts and circumstances that give rise to the change in estimate become known.

Revenue Recognition and Accounting for Commodity Derivative Instruments

Our operating revenues are composed of (i) power and steam revenue consisting of fixed capacity payments, which are not related to production, variable energy payments, which are related to production, host steam and thermal energy sales, and other revenues such as RMR Contracts, resource adequacy and certain ancillary service revenues, (ii) revenues from derivative instruments as a result of our marketing, hedging and optimization activities, and (iii) other service revenues including revenue related to the sales of combustion turbine component parts and services from TTS and PSM prior to their sale in September 2006 and March 2007, respectively.

Power and Steam

Physical Commodity Contracts — We recognize revenue primarily from the sale of power and steam, a by-product of some of our power production for sale to our customers for use in industrial or other heating operations, upon transmission and delivery to the customer.

We also routinely enter into physical commodity contracts for sales of our generated power to manage risk and capture the value inherent in our generation. Such contracts often meet the criteria of a derivative but are generally eligible for the normal purchase normal sale exception. Certain other contracts do not meet the definition of a derivative and may be considered physical executory contracts or leases. We apply lease or traditional accrual accounting to these contracts that are exempt from derivative accounting or do not meet the definition of a derivative instrument. Additionally, we determine whether the financial statement presentation of revenues should be on a gross or net basis.

With respect to our physical executory contracts, where we act as a principal, we take title of the commodities and assume the risks and rewards of ownership by receiving the natural gas and using the natural gas in our operations to generate and deliver the power. Where we act as principal, we record settlement of our physical commodity contracts on a gross basis. With respect to our physical executory contracts, where we do not take title of the commodities but receive a variable energy payment to convert natural gas into power and steam in a tolling operation, we record revenues on a net basis. Our physical commodity contracts are not entered into for the purpose of settling on a net basis with another counterparty.

RMR Contracts, resource adequacy and other ancillary revenues are recognized when contractually earned and consist of revenues received from our customer either at the market price or a contract price.

Leases — Contracts accounted for as operating leases with minimum lease rentals which vary over time must be levelized. Generally, we levelize these contract revenues on a straight-line basis over the term of the contract.

Derivative Instruments (Marketing, Hedging and Optimization)

We enter into a variety of derivative instruments to include both exchange traded and OTC power and natural gas forwards, options as well as instruments that settle on the power price to natural gas price relationships (Heat Rate swaps and options) and interest rate swaps. The majority of this activity is related to the fuel and power price risk associated with our generation assets and our contractual obligations. We recognize all derivative instruments that qualify for derivative accounting treatment as either assets or liabilities and measure those instruments at fair value unless they qualify for the normal purchase normal sale exemption.

Hedge Accounting — Revenues derived from marketing, hedging and optimization that qualify for hedge accounting are recorded on a net basis in the period that the hedged item is recognized into earnings. Hedge accounting requires us to formally document, designate and assess the effectiveness of transactions that receive hedge accounting. For revenues derived from marketing, hedging and optimization contracts that do not qualify for hedge accounting treatment and for certain forward physical PPAs that do not qualify for the normal purchase normal sale exemption under derivative accounting, revenues are recognized currently into earnings as mark-to-market activity.

We report the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument as a component of OCI and reclassify such gains and losses into earnings in the same period during which the hedged forecasted transaction affects earnings. The remaining gain or loss on the derivative instrument, if any, must be recognized currently in earnings. Changes in fair value of derivatives designated as fair value hedges and the corresponding changes in the fair value of the hedged risk attributable to a recognized asset, liability, or unrecognized firm commitment is recorded in earnings. If the fair value hedge is effective, the amounts recorded will offset in earnings.

With respect to cash flow hedges, if it is determined that the forecasted transaction is no longer probable of occurring, then hedge accounting will be discontinued prospectively and the associated gain or loss previously deferred in OCI is reclassified into current income. If the hedging instrument is terminated or de-designated prior to the occurrence of the hedged forecasted transaction, the gain or loss associated with the hedge instrument remains deferred in OCI until such time as the forecasted transaction impacts earnings, or until it is determined that the forecasted transaction is no longer probable of occurring.

With respect to fair value hedges, if the underlying asset, liability or firm commitment being hedged is disposed of or otherwise terminated, the gain or loss associated with the underlying hedged item is recognized currently in earnings. If the hedging instrument is terminated or de-designated prior to the settlement of the hedged asset, liability or firm commitment, the adjustment of the carrying amount of the hedged item would remain until the hedged item is recognized in earnings.

We present the cash flows from our derivatives in the same category as the item being hedged within operating activities on our Consolidated Statements of Cash Flows unless they contain an other-than-insignificant financing element in which case their cash flows are classified within financing activities.

Mark-to-Market Activity — A component of operating revenues (for power contracts), fuel and purchased energy expense (for natural gas contracts) and interest expense for interest rate swaps, includes realized settlements and unrealized mark-to-market gains and losses resulting from general market price movements on power, natural gas and interest rate swap derivative instruments not designated or not qualifying as cash flow hedges. Gains and losses due to ineffectiveness on commodity hedging instruments are also included in unrealized mark-to-market gains and losses.

Significant judgment and estimates used in accounting for our derivative instruments include contract interpretation, valuation techniques and assumptions, assumptions used in forecasting future generation and market expectations. Effective January 1, 2008, we adopted SFAS No. 157, which provides a framework for measuring fair value under GAAP and, among other things, requires enhanced disclosures about assets and liabilities carried at fair value. As defined in SFAS No. 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in the principal or most advantageous market in an orderly transaction between market participants at the measurement date (exit price). SFAS No. 157 establishes a fair value hierarchy from level 1 through level 3 that prioritizes the inputs used to measure fair value.

The following is a summary of the most significant estimates and assumptions associated with the calculation of fair value of our commodity derivative instruments. See "— Risk Management and Commodity Accounting" for a sensitivity analysis of the fair value of our commodity derivative instruments.

Pricing — We utilize market data (such as pricing services and broker quotes) and assumptions that we believe market participants would use in pricing our assets or liabilities including assumptions about risks and the risks inherent to the inputs in the valuation technique. These inputs can be readily observable, market corroborated or generally unobservable. We primarily apply the market approach and income approach for recurring fair value measurements and utilize what we believe to be the best available information. We utilize valuation techniques that seek to maximize the use of observable inputs and minimize the use of unobservable inputs.

Valuation Techniques — In certain instances, we utilize models to measure fair value. These models are primarily industry-standard models, including the Black-Scholes pricing model, that incorporate various assumptions, including quoted interest rates and time value, as well as other relevant economic measures. Our valuation models may incorporate historical correlation information and extrapolate available broker and other information to future periods. In cases where there is no corroborating market information available to support significant model inputs, we initially use the transaction price as the best estimate of fair value.

Credit Reserves — We assess non-performance risk by adjusting the fair value of our derivatives based on the credit standing of the counterparties involved and the impact of credit enhancements, if any. Such valuation adjustments represent the amount of probable loss due to default either by us or a third party. Our credit valuation methodology is based on a quantitative approach which allocates a credit adjustment to the fair value of derivative transactions based on the net exposure of each counterparty. We develop our credit reserve based on our expectation of the market participants' perspective of potential credit exposure. Our calculation of the credit reserve on net asset positions is based on available market information including credit default swap rates, credit ratings and historical default information. We also incorporate non-performance risk in net liability positions based on an assessment of our potential risk of default.

See Note 11 of the Notes to Consolidated Financial Statements for further discussion of our commodity derivative instruments.

Accounting for VIEs and Financial Statement Consolidation Criteria

We adopted the disclosure requirements under newly issued FSP No. FAS 140-4 and FIN 46(R)-8, "Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interest in Variable Interest Entities." Our primary VIEs are entered into as part of subordinated and/or project debt, monetization of assets, joint ventures, PPAs and contracts with third parties which contain purchase or sale options. We consolidate all VIEs where we are the primary beneficiary. This determination is made at the inception of our involvement with the VIE. We consider both qualitative and quantitative factors and form a conclusion that we, or another interest holder, absorb a majority of the entity's risk for expected losses, receive a majority of the entity's potential for expected residual returns, or both.

Making these determinations can require the use of significant judgment, both on a qualitative and quantitative basis, which include, but are not limited to:

- Consideration of the design of the VIE, its purpose and variability is designed to create and pass along to its interest holders;
- Preparation of future expected financial results and future expected cash flows from the VIE;
- Assigning probabilities to future events, markets and potential outcomes, such as the exercise of purchase options;
- Estimates in future residual fair values of power plant assets years into the future; and
- Determinations of our counterparties' reasons and intentions for entering into the VIE.

If we determine that we will absorb a majority of a VIE's expected losses, receive a majority of the entity's potential for expected residual returns or both, we consolidate the VIE in accordance with GAAP into our Consolidated Financial Statements. We re-evaluate our initial determination that consolidation is appropriate only when a reconsideration event occurs. Examples of reconsideration events include; but are not limited to:

- The primary beneficiary sells or otherwise disposes of all or part of its variable interests to unrelated parties;

- The VIE issues new variable interests to parties other than the primary beneficiary or the primary beneficiary's related parties; and

- The entity's governing documents or contractual arrangements are changed in a manner that reallocates between the existing primary beneficiary and other unrelated parties (a) the obligation to absorb the expected losses of the VIE or (b) the right to receive the expected residual returns of the VIE.

We do not consolidate VIE's where we are not the primary beneficiary. Our unconsolidated investments in VIEs consist of our subsidiaries with purchase option rights where we have determined, at the inception of our involvement with the VIE, that we are not the primary beneficiary. We also have joint venture and equity interests where we do not demonstrate significant control and thus, we are not the primary beneficiary of the joint venture of equity interest. We account for these unconsolidated VIEs, joint venture and equity interests under the equity method of accounting and include our net investment in investments on our Consolidated Balance Sheets. Our equity interest in the net income from our unconsolidated VIEs is recorded in other operating expense on a net basis.

Impairment Evaluation of Long-Lived Assets

We evaluate our long-lived assets, such as property, plant and equipment, equity method investments, turbine equipment, patents, and specifically identified intangibles, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. Examples of such events or changes in circumstances are:

- a significant decrease in the market price of a long-lived asset,

- a significant adverse change in the manner an asset is being used or its physical condition,

- an adverse action by a regulator or legislature or an adverse change in the business climate,

- an accumulation of costs significantly in excess of the amount originally expected for the construction or acquisition of an asset,

- a current-period loss combined with a history of losses or the projection of future losses, or

- a change in our intent about an asset from an intent to hold to a greater than 50% likelihood that an asset will be sold or disposed of before the end of its previously estimated useful life.

When we believe an impairment condition may have occurred, we are required to estimate the undiscounted future cash flows associated with a long-lived asset or group of long-lived assets at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities for long-lived assets that are expected to be held and used. We evaluate our operating power plants as a whole. Equipment assigned to each power plant is not evaluated for impairment separately, as it is integral to the assumed future operations of the power plant to which it is assigned.

All construction and development projects are reviewed for impairment whenever there is an indication of potential reduction in fair value. If it is determined that it is no longer probable that the projects will be completed and all capitalized costs recovered through future operations, the carrying values of the projects would be written down to the recoverable value.

When we determine that our assets meet the assets held-for-sale criteria, they are reported at the lower of the carrying amount or fair value less the cost to sell. We are also required to evaluate our equity method investments to determine whether or not they are impaired when the value is considered an "other than a temporary" decline in value.

If we determine that the undiscounted cash flows from an asset to be held and used are less than the carrying amount of the asset, or if we have classified an asset as held for sale, we must estimate fair value to determine the amount of any impairment charge.

The following summarizes some of the most significant estimates and assumptions used in evaluating if we have an impairment charge.

Undiscounted Expected Future Cash Flows — In order to estimate future cash flows, we consider historical cash flows and changes in the market environment and other factors that may affect future cash flows. To the extent applicable, the assumptions we use are consistent with forecasts that we are otherwise required to make (for example, in preparing our other earnings forecasts). Certain of our operating plants are located in regions with depressed demand and Commodity Margin. Our forecasts generally assume that Commodity Margin will increase in future years in these regions as the supply and demand relationships improve. The use of this method involves inherent uncertainty. We use our best estimates in making these evaluations and consider various factors, including forward price curves for energy, fuel costs, and operating costs. However, actual future market prices and project costs could vary from the assumptions used in our estimates, and the impact of such variations could be material.

Fair Value — Generally, fair value will be determined using valuation techniques such as the present value of expected future cash flows. We will also discount the estimated future cash flows associated with the asset using a single interest rate representative of the risk involved with such an investment. We may also consider prices of similar assets, consult with brokers, or employ other valuation techniques. We use our best estimates in making these evaluations; however, actual future market prices and project costs could vary from the assumptions used in our estimates, and the impact of such variations could be material.

The evaluation and measurement of impairments for equity method investments involve the same uncertainties as described for long-lived assets that we own directly. Similarly, our estimates that we make with respect to our equity and cost-method investments are subjective, and the impact of variations in these estimates could be material.

See Note 2 of the Notes to Consolidated Financial Statements for further discussion of our impairment evaluation of long-lived assets.

Accounting for Income Taxes

To arrive at our consolidated income tax provision and other tax balances, significant judgment is required. Although we believe that our estimates are reasonable, no assurance can be given that the final tax outcome of these matters will not be different than that which is reflected in our historical tax provisions and accruals. Such differences could have a material impact on our income tax provision, other tax accounts and net income in the period in which such determination is made.

As of December 31, 2008, our NOL and credit carryforwards consists of federal carryforwards of approximately $7.5 billion which expire between 2023 and 2028. This includes an NOL carryforward of approximately $396 million for our CCFC group.

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

GAAP requires that we consider all available evidence and tax planning strategies, both positive and negative, to determine whether, based on the weight of that evidence, a valuation allowance is needed. Future realization of the tax benefit of an existing deductible temporary difference or carryforward ultimately depends on the existence of sufficient taxable income of the appropriate character within the carryback or carryforward periods available under the tax law. Due to our history of losses, we were unable to assume future profits; however, at December 31, 2007, we were able to consider available tax planning strategies due to our imminent emergence from Chapter 11. Future income from reversals of existing taxable temporary differences and tax planning strategies allowed a larger portion of the deferred tax assets to be offset against deferred tax liabilities resulting in a significant release of previously recorded valuation allowances.

As of December 31, 2008, we have provided a valuation allowance of $2.7 billion on certain federal, state and foreign tax jurisdiction deferred tax assets to reduce the gross amount of these assets to the extent necessary to result in an amount that is more likely than not of being realized. For the years ended December 31, 2008, 2007 and 2006, the net change in the valuation allowance was an increase of $284 million, $80 million and $682 million, respectively, and primarily relates to NOL carryforwards.

In the ordinary course of business, there are many transactions and calculations where the ultimate tax outcome is uncertain. Some of these uncertainties arise as a consequence of the treatment of capital assets, financing transactions, multistate taxation of operations and segregation of foreign and domestic income and expense to avoid double taxation. We recognize the financial statement effects of a tax position when it is more likely than not, based on the technical merits, that the position will be sustained upon examination. A tax position that meets the more-likely-than-not recognition threshold is measured as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement with a taxing authority. We derecognize previously recognized tax positions in the first period in which it is no longer more-likely-than-not that the tax position would be sustained upon examination. The determination and calculation of uncertain tax positions involves significant judgment in the application of complex tax laws. Resolution of these uncertainties in a manner inconsistent with our expectations could have a material impact on our financial condition or results of operations. As of December 31, 2008, we have $90 million of unrecognized tax benefits from uncertain tax positions.

See Note 9 of the Notes to Consolidated Financial Statements for further discussion of our accounting for income taxes.

Initial Adoption of New Accounting Standards in 2008

On January 1, 2008, we adopted SFAS No. 157, "Fair Value Measurements," related to financial assets and financial liabilities. See Note 10 of the Notes to Consolidated Financial Statements for a discussion of the impact of adopting of SFAS No. 157. We also adopted the provisions of FSP No. FAS 140-4 and FIN 46(R)-8, "Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interest in Variable Interest Entities," in December 2008. See Note 5 of the Notes to Consolidated Financial Statements for a further discussion of our involvement with VIEs.

Item 7A. ***Quantitative and Qualitative Disclosures about Market Risk***

The information required hereunder is set forth under Item 7. "Management's Discussion and Analysis of Financial Condition and Results of Operations — Risk Management and Commodity Accounting."

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

The information required hereunder is set forth under "Report of Independent Registered Public Accounting Firm," "Consolidated Balance Sheets," "Consolidated Statements of Operations," "Consolidated Statements of Comprehensive Income (Loss) and Stockholders' Equity (Deficit)," "Consolidated Statements of Cash Flows," and "Notes to Consolidated Financial Statements" included in the Consolidated Financial Statements that are a part of this Report. Other financial information and schedules are included in the Consolidated Financial Statements that are a part of this Report.

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

None.

Item 9A. ***Controls and Procedures***

Disclosure Controls and Procedures

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

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

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting. Our internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with GAAP.

Our internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with GAAP, and that receipts and expenditures of the Company are being made only in accordance with authorizations of management and directors of the Company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Company's assets that could have a material effect on the financial statements.

Management has assessed the effectiveness of our internal control over financial reporting as of December 31, 2008. In making its assessment of internal control over financial reporting, management used the criteria described in *Internal Control — Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

Based on management's assessment, we have concluded that our internal control over financial reporting was effective as of December 31, 2008.

The effectiveness of our internal control over financial reporting as of December 31, 2008, has been audited by PricewaterhouseCoopers LLP, an independent registered public accounting firm, as stated in their report which appears herein.

Changes in Internal Control Over Financial Reporting

During the fourth quarter of 2008, there were no changes in our internal control over financial reporting that materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. ***Other Information***

None.

PART III

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

Information appearing under this Item is incorporated herein by reference to the similarly named section in our proxy statement for the 2009 annual meeting of stockholders to be held May 7, 2009.

Item 11. ***Executive Compensation***

Information appearing under this Item is incorporated herein by reference to the similarly named section in our proxy statement for the 2009 annual meeting of stockholders to be held May 7, 2009.

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

Information appearing under this Item is incorporated herein by reference to the similarly named section in our proxy statement for the 2009 annual meeting of stockholders to be held May 7, 2009.

Item 13. ***Certain Relationships and Related Transactions, and Director Independence***

Information appearing under this Item is incorporated herein by reference to the similarly named section in our proxy statement for the 2009 annual meeting of stockholders to be held May 7, 2009.

Item 14. ***Principal Accounting Fees and Services***

Information appearing under this Item is incorporated herein by reference to the similarly named section in our proxy statement for the 2009 annual meeting of stockholders to be held May 7, 2009.

PART IV

Item 15. *Exhibits, Financial Statement Schedule*

Exhibit Number	Description
2.1	Debtors' Sixth Amended Joint Plan of Reorganization Pursuant to Chapter 11 of the United States Bankruptcy Code (incorporated by reference to Exhibit 2.1 to the Company's Current Report on Form 8-K filed with the SEC on December 27, 2007).
2.2	Findings of Fact, Conclusions of Law, and Order Confirming Sixth Amended Joint Plan of Reorganization Pursuant to Chapter 11 of the Bankruptcy Code (incorporated by reference to Exhibit 2.2 to the Company's Current Report on Form 8-K filed with the SEC on December 27, 2007).
3.1	Amended and Restated Certificate of Incorporation of the Company, as amended (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed with the SEC on February 1, 2008).
3.2	Amended and Restated By-Laws of the Company (incorporated by reference to Exhibit 3.2 to the Company's Current Report on Form 8-K, filed with the SEC on February 1, 2008).
4.1	Indenture, dated as of June 13, 2003, between Power Contract Financing, L.L.C. and Wilmington Trust Company, as Trustee, Accounts Agent, Paying Agent and Registrar, including form of Notes (incorporated by reference to Exhibit 4.4 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2003, filed with the SEC on August 14, 2003).
4.2.1	Indenture, dated as of August 14, 2003, among Calpine Construction Finance Company, L.P., CCFC Finance Corp., each of Calpine Hermiston, LLC, CPN Hermiston, LLC and Hermiston Power Partnership, as Guarantors, and Wilmington Trust FSB, as Trustee, including form of Notes (incorporated by reference to Exhibit 4.4 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2003, filed with the SEC on November 13, 2003).
4.2.2	Supplemental Indenture, dated as of September 18, 2003, among Calpine Construction Finance Company, L.P., CCFC Finance Corp., each of Calpine Hermiston, LLC, CPN Hermiston, LLC and Hermiston Power Partnership, as Guarantors, and Wilmington Trust FSB, as Trustee (incorporated by reference to Exhibit 4.5 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2003, filed with the SEC on November 13, 2003).
4.2.3	Second Supplemental Indenture, dated as of January 14, 2004, among Calpine Construction Finance Company, L.P., CCFC Finance Corp., each of Calpine Hermiston, LLC, CPN Hermiston, LLC and Hermiston Power Partnership, as Guarantors, and Wilmington Trust FSB, as Trustee (incorporated by reference to Exhibit 4.14.3 to the Company's Annual Report on Form 10-K for the year ended December 31, 2003, filed with the SEC on March 25, 2004).
4.2.4	Third Supplemental Indenture, dated as of March 5, 2004, among Calpine Construction Finance Company, L.P., CCFC Finance Corp., each of Calpine Hermiston, LLC, CPN Hermiston, LLC and Hermiston Power Partnership, as Guarantors, and Wilmington Trust FSB, as Trustee (incorporated by reference to Exhibit 4.14.4 to the Company's Annual Report on Form 10-K for the year ended December 31, 2003, filed with the SEC on March 25, 2004).
4.2.5	Fourth Supplemental Indenture, dated as of March 15, 2006, among Calpine Construction Finance Company, L.P., CCFC Finance Corp., each of Calpine Hermiston, LLC, CPN Hermiston, LLC and Hermiston Power Partnership, as Guarantors, and Wilmington Trust FSB, as Trustee (incorporated by reference to Exhibit 4.13.5 to the Company's Annual Report on Form 10-K for the year ended December 31, 2005, filed with the SEC on May 19, 2006).
4.2.6	Waiver Agreement, dated as of March 15, 2006, among Calpine Construction Finance Company, L.P., CCFC Finance Corp., each of Calpine Hermiston, LLC, CPN Hermiston, LLC and Hermiston Power Partnership, as Guarantors, and Wilmington Trust FSB, as Trustee (incorporated by reference to Exhibit 4.13.6 to the Company's Annual Report on Form 10-K for the year ended December 31, 2005, filed with the SEC on May 19, 2006).

Exhibit Number	Description
4.2.7	Waiver Agreement, dated as of June 9, 2006, among Calpine Construction Finance Company, L.P., CCFC Finance Corp., each of Calpine Hermiston, LLC, CPN Hermiston, LLC and Hermiston Power Partnership, as Guarantors, and Wilmington Trust FSB, as Trustee (incorporated by reference to Exhibit 4.1.7 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2006, filed with the SEC on July 3, 2006).
4.2.8	Amendment to Waiver Agreement, dated as of August 4, 2006, among Calpine Construction Finance Company, L.P., CCFC Finance Corp., each of Calpine Hermiston, LLC, CPN Hermiston, LLC and Hermiston Power Partnership, as Guarantors, and Wilmington Trust FSB, as Trustee (incorporated by reference to Exhibit 4.13.8 to the Company's Annual Report on Form 10-K for the year ended December 31, 2006, filed with the SEC on March 14, 2007).
4.2.9	Second Amendment to Waiver Agreement, dated as of August 11, 2006, among Calpine Construction Finance Company, L.P., CCFC Finance Corp., each of Calpine Hermiston, LLC, CPN Hermiston, LLC and Hermiston Power Partnership, as Guarantors, and Wilmington Trust FSB, as Trustee (incorporated by reference to Exhibit 4.1.9 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2006, filed with the SEC on August 14, 2006).
4.2.10	Fifth Supplemental Indenture, dated as of August 25, 2006, among Calpine Construction Finance Company, L.P., CCFC Finance Corp., each of Calpine Hermiston, LLC, CPN Hermiston, LLC and Hermiston Power Partnership, as Guarantors, and Wilmington Trust FSB, as Trustee (incorporated by reference to Exhibit 4.1.6 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, filed with the SEC on November 9, 2006).
4.3	Indenture, dated as of September 30, 2003, among Gilroy Energy Center, LLC, each of Creed Energy Center, LLC and Goose Haven Energy Center, as Guarantors, and Wilmington Trust Company, as Trustee and Collateral Agent, including form of Notes (incorporated by reference to Exhibit 4.6 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2003, filed with the SEC on November 13, 2003).
4.4	Third Priority Indenture, dated as of March 23, 2004, among Calpine Generating Company, LLC, CalGen Finance Corp. and Manufacturers and Traders Trust Company (as successor trustee to Wilmington Trust FSB), as Trustee, including form of Notes (incorporated by reference to Exhibit 4.21 to the Company's Annual Report on Form 10-K for the year ended December 31, 2003, filed with the SEC on March 25, 2004).
4.5	Indenture, dated as of June 2, 2004, between Power Contract Financing III, LLC and Wilmington Trust Company, as Trustee, Accounts Agent, Paying Agent and Registrar, including form of Notes (incorporated by reference to Exhibit 4.6 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2004, filed with the SEC on August 9, 2004).
4.6.1	Second Amended and Restated Limited Liability Company Operating Agreement of CCFC Preferred Holdings, LLC, dated as of October 14, 2005, containing terms of its 6-Year Redeemable Preferred Shares Due 2011 (incorporated by reference to Exhibit 4.21.1 to the Company's Annual Report on Form 10-K for the year ended December 31, 2005, filed with the SEC on May 19, 2006).
4.6.2	Consent, Acknowledgment and Amendment, dated as of March 15, 2006, among Calpine CCFC Holdings, Inc. and the Redeemable Preferred Members party thereto (incorporated by reference to Exhibit 4.21.2 to the Company's Annual Report on Form 10-K for the year ended December 31, 2005, filed with the SEC on May 19, 2006).
4.6.3	Amendment to Second Amended and Restated Limited Liability Company Operating Agreement of CCFC Preferred Holdings, LLC, dated as of October 24, 2006, among Calpine CCFC Holdings, Inc., in its capacity as Common Member, and the Redeemable Preferred Members party thereto (incorporated by reference to Exhibit 4.2.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, filed with the SEC on November 9, 2006).

Exhibit Number	Description
4.7	Registration Rights Agreement, dated January 31, 2008, among the Company and each Participating Shareholder named therein (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on February 6, 2008).
10.1	Exit Financing Agreements
10.1.1	Credit Agreement, dated as of January 31, 2008, among the Company, as borrower, Goldman Sachs Credit Partners L.P., Credit Suisse, Deutsche Bank Securities Inc. and Morgan Stanley Senior Funding, Inc., as co-documentation agents and as co-syndication agents, General Electric Capital Corporation, as sub-agent for the revolving lenders, Goldman Sachs Credit Partners L.P., as administrative agent and as collateral agent and each of the financial institutions from time to time party thereto (incorporated by reference to Exhibit 4.1 to the Company's Current Report on Form 8-K filed with the SEC on February 1, 2008).
10.1.2	Bridge Loan Agreement, dated as of January 31, 2008, among Calpine Corporation, Goldman Sachs Credit Partners L.P., Credit Suisse, Deutsche Bank Securities Inc. and Morgan Stanley Senior Funding, Inc., as co-documentation agents and as co-syndication agents, Goldman Sachs Credit Partners L.P., as administrative agent and as collateral agent and each of the financial institutions from time to time party thereto (incorporated by reference to Exhibit 4.2 to the Company's Current Report on Form 8-K filed with the SEC on February 1, 2008).
10.1.3	Guaranty and Collateral Agreement, dated as of January 31, 2008, made by the Company and certain of the Company's subsidiaries party thereto in favor of Goldman Sachs Credit Partners, L.P., as collateral agent (incorporated by reference to Exhibit 10.1.3 to the Company's Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 29, 2008).
10.2	DIP Financing Agreements
10.2.1.1	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 (incorporated by reference to Exhibit 10.1.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, filed with the SEC on May 9, 2007).
10.2.1.2	Security and Pledge Agreement, dated as of March 29, 2007, by and among the Company, as borrower, certain of the Company's subsidiaries, as grantors, and Credit Suisse, as collateral agent (incorporated by reference to Exhibit 10.1.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2007, filed with the SEC on May 9, 2007).
10.3	Financing and Term Loan Agreements
10.3.1	Commodity Collateral Revolving Credit Agreement, dated as of July 8, 2008, among Calpine Corporation as Borrower, Goldman Sachs Credit Partners L.P. as Payment Agent, sole Lead Arranger and sole Bookrunner, and the Lenders from time to time party thereto (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on July 14, 2008).

Exhibit Number	Description
10.3.2.1	Credit and Guarantee Agreement, dated as of August 14, 2003, among Calpine Construction Finance Company, L.P., each of Calpine Hermiston, LLC, CPN Hermiston, LLC and Hermiston Power Partnership, as Guarantors, the Lenders named therein, and Goldman Sachs Credit Partners L.P., as Administrative Agent and Sole Lead Arranger (incorporated by reference to Exhibit 10.29 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2003, filed with the SEC on November 13, 2003).
10.3.2.2	Amendment No. 1 Under Credit and Guarantee Agreement, dated as of September 12, 2003, among Calpine Construction Finance Company, L.P., each of Calpine Hermiston, LLC, CPN Hermiston, LLC and Hermiston Power Partnership, as Guarantors, the Lenders named therein, and Goldman Sachs Credit Partners L.P., as Administrative Agent and Sole Lead Arranger (incorporated by reference to Exhibit 10.30 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2003, filed with the SEC on November 13, 2003).
10.3.2.3	Amendment No. 2 Under Credit and Guarantee Agreement, dated as of January 13, 2004, among Calpine Construction Finance Company, L.P., each of Calpine Hermiston, LLC, CPN Hermiston, LLC and Hermiston Power Partnership, as Guarantors, the Lenders named therein, and Goldman Sachs Credit Partners L.P., as Administrative Agent and Sole Lead Arranger (incorporated by reference to Exhibit 10.2.2.3 to the Company's Annual Report on Form 10-K for the year ended December 31, 2003, filed with the SEC on March 25, 2004).
10.3.2.4	Amendment No. 3 Under Credit and Guarantee Agreement, dated as of March 5, 2004, among Calpine Construction Finance Company, L.P., each of Calpine Hermiston, LLC, CPN Hermiston, LLC and Hermiston Power Partnership, as Guarantors, the Lenders named therein, and Goldman Sachs Credit Partners L.P., as Administrative Agent and Sole Lead Arranger (incorporated by reference to Exhibit 10.2.2.4 to the Company's Annual Report on Form 10-K for the year ended December 31, 2003, filed with the SEC on March 25, 2004).
10.3.2.5	Amendment No. 4 Under Credit and Guarantee Agreement, dated as of March 15, 2006, among Calpine Construction Finance Company, L.P., each of Calpine Hermiston, LLC, CPN Hermiston, LLC and Hermiston Power Partnership, as Guarantors, the Lenders named therein, and Goldman Sachs Credit Partners L.P., as Administrative Agent and Sole Lead Arranger (incorporated by reference to Exhibit 10.2.6.5 to the Company's Annual Report on Form 10-K for the year ended December 31, 2005, filed with the SEC on May 19, 2006).
10.3.2.6	Waiver Agreement, dated as of March 15, 2006 among Calpine Construction Finance Company, L.P., each of Calpine Hermiston, LLC, CPN Hermiston, LLC and Hermiston Power Partnership, as Guarantors, the Lenders named therein, and Goldman Sachs Credit Partners L.P., as Administrative Agent and Sole Lead Arranger (incorporated by reference to Exhibit 10.2.6.6 to the Company's Annual Report on Form 10-K for the year ended December 31, 2005, filed with the SEC on May 19, 2006).
10.3.2.7	Waiver Agreement, dated as of June 9, 2006, among Calpine Construction Finance Company, L.P., each of Calpine Hermiston, LLC, CPN Hermiston, LLC and Hermiston Power Partnership, as Guarantors, the Lenders named therein, and Goldman Sachs Credit Partners L.P., as Administrative Agent and Sole Lead Arranger (incorporated by reference to Exhibit 10.2.1.7 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2006, filed with the SEC on July 3, 2006).
10.3.2.8	Amendment to Waiver Agreement, dated as of August 4, 2006, among Calpine Construction Finance Company, L.P., CCFC Finance Corp., each of Calpine Hermiston, LLC, CPN Hermiston, LLC and Hermiston Power Partnership, as Guarantors, the Lenders named therein, and Goldman Sachs Credit Partners L.P., as Administrative Agent and Sole Lead Arranger (incorporated by reference to Exhibit 10.2.1.8 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2006, filed with the SEC on August 14, 2006).

Exhibit Number	Description
10.3.2.9	Second Amendment to Waiver Agreement, dated as of August 11, 2006, among Calpine Construction Finance Company, L.P., CCFC Finance Corp., each of Calpine Hermiston, LLC, CPN Hermiston, LLC and Hermiston Power Partnership, as Guarantors, the Lenders named therein, and Goldman Sachs Credit Partners L.P., as Administrative Agent and Sole Lead Arranger (incorporated by reference to Exhibit 10.2.1.9 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2006, filed with the SEC on August 14, 2006).
10.3.2.10	Amendment No. 5 Under Credit and Guarantee Agreement, dated as of August 25, 2006, among Calpine Construction Finance Company, L.P., each of Calpine Hermiston, LLC, CPN Hermiston, LLC and Hermiston Power Partnership, as Guarantors, the Lenders named therein, and Goldman Sachs Credit Partners L.P., as Administrative Agent and Sole Lead Arranger (incorporated by reference to Exhibit 10.2.1.6 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2006, filed with the SEC on November 9, 2006).
10.3.3	Credit Agreement, dated as of June 24, 2004, among Riverside Energy Center, LLC, the Lenders named therein, Union Bank of California, N.A., as the Issuing Bank, Credit Suisse First Boston, acting through its Cayman Islands Branch, as Lead Arranger, Book Runner, Administrative Agent and Collateral Agent, and CoBank, ACB, as Syndication Agent (incorporated by reference to Exhibit 10.1.9 to the Company's Annual Report on Form 10-K for the year ended December 31, 2004, filed with the SEC on March 31, 2005).
10.3.4	Credit Agreement, dated as of June 24, 2004, among Rocky Mountain Energy Center, LLC, the Lenders named therein, Union Bank of California, N.A., as the Issuing Bank, Credit Suisse First Boston, acting through its Cayman Islands Branch, as Lead Arranger, Book Runner, Administrative Agent and Collateral Agent, and CoBank, ACB, as Syndication Agent (incorporated by reference to Exhibit 10.1.10 to the Company's Annual Report on Form 10-K for the year ended December 31, 2004, filed with the SEC on March 31, 2005).
10.3.5	Credit Agreement, dated as of February 25, 2005, among Calpine Steamboat Holdings, LLC, the Lenders named therein, Calyon New York Branch, as a Lead Arranger, Underwriter, Co-Book Runner, Administrative Agent, Collateral Agent and LC Issuer, CoBank, ACB, as a Lead Arranger, Underwriter, Co-Syndication Agent and Co-Book Runner, HSH Nordbank AG, as a Lead Arranger, Underwriter and Co-documentation Agent, UFJ Bank Limited, as a Lead Arranger, Underwriter and Co-Documentation Agent, and Bayerische Hypo-Und Vereinsbank AG, New York Branch, as a Lead Arranger, Underwriter and Co-Syndication Agent (incorporated by reference to Exhibit 10.1.11 to the Company's Annual Report on Form 10-K for the year ended December 31, 2004, filed with the SEC on March 31, 2005).
10.4	Management Contracts or Compensatory Plans or Arrangements
10.4.1.1	Employment Agreement, dated August 10, 2008, between the Company and Jack A. Fusco (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on August 12, 2008).†
10.4.1.2	Calpine Corporation Executive Sign On Non-Qualified Stock Option Agreement (Jack A. Fusco) (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed with the SEC on August 12, 2008).†
10.4.2.1	Second Amended and Restated Employment Agreement, effective as of March 25, 2008, between the Company and Mr. Robert P. May (incorporated by reference to Exhibit 10.2.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, filed with the SEC on May 12, 2008).†

Exhibit Number	Description
10.4.2.2	Amended and Restated Chief Executive Officer Emergence Restricted Stock Agreement (Pursuant to the 2008 Equity Incentive Plan) between the Company and Robert P. May (incorporated by reference to Exhibit 10.2.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 30, 2008, filed with the SEC on May 12, 2008).†
10.4.2.3	Chief Executive Officer Non-Qualified Stock Option Agreement (Pursuant to the 2008 Equity Incentive Plan), dated March 25, 2008, between the Company and Robert P. May (incorporated by reference to Exhibit 10.2.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, filed with the SEC on May 12, 2008).†
10.4.3.1	Letter Agreement and Addendum dated June 30, 2008, between the Company and Zamir Rauf (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on July 3, 2008).†
10.4.3.2	Letter Agreement, dated December 17, 2008, between the Company and Zamir Rauf (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on December 19, 2008).†
10.4.4.1	Agreement, dated December 17, 2005, between the Company and AP Services, LLC (incorporated by reference to Exhibit 10.5.3.1 to the Company's Annual Report on Form 10-K for the year ended December 31, 2006, filed with the SEC on March 14, 2007).†
10.4.4.2	Letter Agreement, dated November 3, 2006, between the Company and AP Services, LLC, amending the Agreement, dated December 17, 2005, between the Company and AP Services (incorporated by reference to Exhibit 10.5.3.2 to the Company's Annual Report on Form 10-K for the year ended December 31, 2006, filed with the SEC on March 14, 2007).†
10.4.5.1	Letter Agreement, dated September 1, 2008, between the Company and John B. Hill (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on September 4, 2008).†
10.4.5.2	Calpine Corporation Executive Sign On Non-Qualified Stock Option Agreement (John B. Hill) (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed with the SEC on September 4, 2008).†
10.4.6.1	Employment Agreement, dated August 11, 2008, between the Company and W. Thaddeus Miller (incorporated by reference to Exhibit 10.2.7 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2008, filed with the SEC on November 7, 2008).†
10.4.6.2	Calpine Corporation Executive Sign On Non-Qualified Stock Option Agreement (Miller) (incorporated by reference to Exhibit 4.4 to the Company's Registration Statement on Form S-8 (Registration No. 333-153860) filed with the SEC on October 6, 2008).†
10.4.7	Form of Indemnification Agreement for directors and officers (incorporated by reference to Exhibit 10.11 to the Company's Registration Statement on Form S-1/A (Registration Statement No. 333-07497) filed with the SEC on August 22, 1996).†
10.4.8	Form of Indemnification Agreement for directors and officers (incorporated by reference to Exhibit 10.4.2 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).†
10.4.9	Calpine Corporation U.S. Severance Program (incorporated by reference to Exhibit 10.5.9 to the Company's Annual Report on Form 10-K for the year ended December 31, 2005, filed with the SEC on May 19, 2006).†
10.4.10	Calpine Corporation 2007 Calpine Incentive Plan (incorporated by reference to Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended June 30, 2007, filed with the SEC on August 8, 2007).†

Exhibit Number	Description
10.4.11	Calpine Corporation 2008 Calpine Incentive Plan (incorporated by reference to Exhibit 10.2.9 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2008, filed with the SEC on November 7, 2008).†
10.4.12	Summary of Calpine Emergence Incentive Plan (incorporated by reference to Exhibit 10.5.12 to the Company's Annual Report on Form 10-K for the year ended December 31, 2006, filed with the SEC on March 14, 2007).†
10.4.13.1	Calpine Corporation 2008 Equity Incentive Plan (incorporated by reference to Exhibit 4.5 to the Company's Registration Statement on Form S-8 (No. 333-149074) filed with the SEC on February 6, 2008).†
10.4.13.2	Form of Non-Qualified Stock Option Agreement (Pursuant to the 2008 Equity Incentive Plan) (incorporated by reference to Exhibit 10.4.3 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, filed with the SEC on May 12, 2008).†
10.4.13.3	Form of Restricted Stock Agreement (Pursuant to the 2008 Equity Incentive Plan) (incorporated by reference to Exhibit 10.4.4 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, filed with the SEC on May 12, 2008).†
10.4.13.4	Director's Restricted Stock Unit Agreement (Pursuant to the 2008 Equity Incentive Plan) between the Company and Mr. William J. Patterson (incorporated by reference to Exhibit 10.4.6 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, filed with the SEC on May 12, 2008).†
10.4.13.5	Restricted Stock Unit Election Form between the Company and William J. Patterson (incorporated by reference to Exhibit 10.4.7 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, filed with the SEC on May 12, 2008).†
10.4.14.1	Calpine Corporation 2008 Director Incentive Plan (incorporated by reference to Exhibit 4.4 to the Company's Registration Statement on Form S-8 (No. 333-149074) filed with the SEC on February 6, 2008).†
10.4.14.2	Amendment No. 1 to the Calpine Corporation 2008 Director Incentive Plan.* †
10.4.14.3	Form of Restricted Stock Agreement (Pursuant to the 2008 Director Incentive Plan) (incorporated by reference to Exhibit 10.4.5 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, filed with the SEC on May 12, 2008).†
10.4.15	Calpine Corporation Change in Control and Severance Benefits Plan (incorporated by reference to Exhibit 10.4 to the Company's Current Report on Form 8-K filed with the SEC on February 6, 2008).†
10.4.16.1	Employment Agreement, dated June 19, 2006, between the Company and Mr. Gregory L. Doody (incorporated by reference to Exhibit 10.5.15 to the Company's Annual Report on Form 10-K for the year ended December 31, 2006, filed with the SEC on March 14, 2007).†
10.4.16.2	Amendment, dated July 16, 2008, to Employment Agreement, dated June 19, 2006, between the Company and Gregory L. Doody (incorporated by reference to Exhibit 10.2 to the Company's Current Report on Form 8-K filed with the SEC on July 22, 2008).†
10.4.16.3	Letter dated September 20, 2007, from the Company to Gregory Doody (incorporated by reference to Exhibit 10.4 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2007, filed with the SEC on November 7, 2007).†
10.4.16.4	Letter dated February 11, 2008, from the Company to Mr. Gregory L. Doody (incorporated by reference to Exhibit 10.6.15.3 to the Company's Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 29, 2008).†

Exhibit Number	Description
10.4.17.1	Letter dated September 20, 2007, from the Company to Mr. Michael Rogers (incorporated by reference to Exhibit 10.6.16.1 to the Company's Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 29, 2008).†
10.4.17.2	Letter dated February 11, 2008, from the Company to Mr. Michael D. Rogers (incorporated by reference to Exhibit 10.6.16.2 to the Company's Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 29, 2008).†
10.4.18.1	Letter dated September 20, 2007, from the Company to Mr. Charles B. Clark, Jr. (incorporated by reference to Exhibit 10.6.17.1 to the Company's Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 29, 2008).†
10.4.18.2	Letter dated February 11, 2008, from the Company to Mr. Charles B. Clark, Jr. (incorporated by reference to Exhibit 10.6.17.2 to the Company's Annual Report on Form 10-K for the year ended December 31, 2007, filed with the SEC on February 29, 2008).†
10.4.18.3	Letter Agreement re Employment Separation, dated April 7, 2008 (executed April 11, 2008), between the Company and Mr. Charles B. Clark, Jr. (incorporated by reference to Exhibit 10.3.1 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, filed with the SEC on May 12, 2008).†
10.4.18.4	Consulting Agreement, effective May 30, 2008, between the Company and Mr. Charles B. Clark, Jr. (incorporated by reference to Exhibit 10.3.2 to the Company's Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, filed with the SEC on May 12, 2008).†
10.4.19	Aircraft Travel Card Guidelines (incorporated by reference to Exhibit 10.5 to the Company's Quarterly Report on Form 10-Q for the quarter ended September 30, 2007, filed with the SEC on November 7, 2007).†
21.1	Subsidiaries of the Company.*
23.1	Consent of PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm.*
24.1	Power of Attorney of Officers and Directors of Calpine Corporation (set forth on the signature pages of this report).*
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 Senior Vice President and 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.*

* Filed herewith.

† Management contract or compensatory plan or arrangement.

SIGNATURES

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

CALPINE CORPORATION

By: /s/ ZAMIR RAUF

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

Date: February 26, 2009

POWER OF ATTORNEY

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

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

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

Signature	Title	Date
/s/ JACK A. FUSCO Jack A. Fusco	President, Chief Executive Officer and Director (principal executive officer)	February 26, 2009
/s/ ZAMIR RAUF Zamir Rauf	Executive Vice President and Chief Financial Officer (principal financial officer)	February 26, 2009
/s/ JIM D. DEIDIKER Jim D. Deidiker	Chief Accounting Officer (principal accounting officer)	February 26, 2009
/s/ FRANK CASSIDY Frank Cassidy	Director	February 26, 2009
/s/ ROBERT C. HINCKLEY Robert C. Hinckley	Director	February 26, 2009
/s/ DAVID C. MERRITT David C. Merritt	Director	February 26, 2009
/s/ W. BENJAMIN MORELAND W. Benjamin Moreland	Director	February 26, 2009
Denise M. O'Leary	Director	February 26, 2009
/s/ WILLIAM J. PATTERSON William J. Patterson	Director	February 26, 2009
/s/ J. STUART RYAN J. Stuart Ryan	Director	February 26, 2009
/s/ ROBERT MOSBACHER, JR. Robert Mosbacher, Jr.	Director	February 26, 2009

CALPINE CORPORATION AND SUBSIDIARIES

INDEX TO CONSOLIDATED FINANCIAL STATEMENTS
December 31, 2008

Report of Independent Registered Public Accounting Firm

To the Board of Directors
and Stockholders of Calpine Corporation

In our opinion, the consolidated financial statements listed in the index appearing under Item 15(a)-1 present fairly, in all material respects, the financial position of Calpine Corporation and its subsidiaries at December 31, 2008 and 2007, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2008 in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index appearing under 15(a)-2 presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2008, based on criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's management is responsible for these financial statements and financial statement schedule, for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in Management's Report on Internal Control over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements, on the financial statement schedule, and on the Company's internal control over financial reporting based on our integrated audits. We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As discussed in Note 2 to the consolidated financial statements, the Company adopted the provisions of FSP FIN 39-1, *"Amendment of FASB Interpretation No. 39"* and Statement of Financial Accounting Standards No. 157, *"Fair Value Measurements"* effective January 1, 2008.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (i) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (ii) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (iii) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

/s/ PricewaterhouseCoopers LLP

Houston, Texas
February 26, 2009

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
December 31, 2008 and 2007

	2008	2007
	(in millions, except share and per share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 1,657	$ 1,915
Accounts receivable, net of allowance of $37 and $54	846	878
Accounts receivable, related party	4	226
Inventory	163	114
Margin deposits and other prepaid expense	776	452
Restricted cash, current	337	422
Current derivative assets	3,653	731
Current assets held for sale	—	195
Other current assets	64	98
Total current assets	7,500	5,031
Property, plant and equipment, net	11,908	12,292
Restricted cash, net of current portion	166	159
Investments	144	260
Long-term derivative assets	404	290
Other assets	616	1,018
Total assets	$ 20,738	$ 19,050
LIABILITIES & STOCKHOLDERS' EQUITY (DEFICIT)		
Current liabilities:		
Accounts payable	$ 574	$ 642
Accrued interest payable	85	324
Debt, current portion	716	1,710
Current derivative liabilities	3,799	806
Income taxes payable	5	51
Other current liabilities	437	571
Total current liabilities	5,616	4,104
Debt, net of current portion	9,756	9,946
Deferred income taxes, net of current portion	93	38
Long-term derivative liabilities	698	578
Other long-term liabilities	203	245
Total liabilities not subject to compromise	16,366	14,911
Liabilities subject to compromise	—	8,788
Commitments and contingencies (see Note 16)		
Minority interest	2	3
Stockholders' equity (deficit):		
Preferred stock, $.001 par value per share; authorized 100,000,000 shares, none issued and outstanding in 2008; authorized 10,000,000 shares; none issued and outstanding in 2007	—	—
Common stock, $.001 par value per share; authorized 1,400,000,000 shares, 429,025,057 shares issued and 428,960,025 shares outstanding in 2008; authorized 2,000,000,000 shares, 568,314,685 issued and 479,314,685 outstanding in 2007	1	1
Treasury stock, at cost, 65,032 shares at December 31, 2008 and none at December 31, 2007	(1)	—
Additional paid-in capital	12,217	3,263
Accumulated deficit	(7,689)	(7,685)
Accumulated other comprehensive (loss)	(158)	(231)
Total stockholders' equity (deficit)	4,370	(4,652)
Total liabilities and stockholders' equity (deficit)	$ 20,738	$ 19,050

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

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS
For the Years Ended December 31, 2008, 2007 and 2006

	2008	2007	2006
	(in millions, except share and per share amounts)		
Operating revenues	$ 9,937	$ 7,970	$ 6,937
Cost of revenue:			
Fuel and purchased energy expense	7,281	5,683	4,752
Plant operating expense	918	749	750
Depreciation and amortization expense	433	463	470
Operating plant impairments	33	44	53
Other cost of revenue	114	136	172
Total cost of revenue	8,779	7,075	6,197
Gross profit	1,158	895	740
Sales, general and other administrative expense	215	146	175
Loss from unconsolidated investments in power plants	229	21	—
Other operating expense	26	23	101
Income from operations	688	705	464
Interest expense	1,071	2,019	1,254
Interest (income)	(47)	(64)	(79)
Minority interest (income) expense	(1)	—	5
Other (income) expense, net	27	(139)	13
Loss before reorganization items, income taxes and discontinued operations	(362)	(1,111)	(729)
Reorganization items	(302)	(3,258)	972
Income (loss) before income taxes and discontinued operations	(60)	2,147	(1,701)
Provision (benefit) for income taxes	(47)	(546)	64
Income (loss) before discontinued operations	(13)	2,693	(1,765)
Discontinued operations, net of tax provision of $14 in 2008	23	—	—
Net income (loss)	$ 10	$ 2,693	$ (1,765)
Basic earnings (loss) per common share:			
Weighted average shares of common stock outstanding (in thousands)	485,054	479,235	479,136
Income (loss) before discontinued operations	$ (0.03)	$ 5.62	$ (3.68)
Discontinued operations, net of tax	0.05	—	—
Net income (loss) per share — basic	$ 0.02	$ 5.62	$ (3.68)
Diluted earnings (loss) per common share:			
Weighted average shares of common stock outstanding (in thousands)	485,546	479,478	479,136
Income (loss) before discontinued operations	$ (0.03)	$ 5.62	$ (3.68)
Discontinued operations, net of tax	0.05	—	—
Net income (loss) per share — diluted	$ 0.02	$ 5.62	$ (3.68)

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

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS) AND STOCKHOLDERS' EQUITY (DEFICIT)
For the Years Ended December 31, 2008, 2007 and 2006

	Common Stock	Treasury Stock	Additional Paid-In Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss) Net Unrealized Gain (Loss) From Cash Flow Hedges	Total Foreign Currency Translation	Stockholders' Equity (Deficit)
	(In millions except share amounts)						
Balance, December 31, 2005	$ 1	$ —	$ 3,265	$ (8,613)	$ (159)	$ (2)	$ (5,508)
Return of 39,000,000 shares of loaned common stock	—	—	(113)	—	—	—	(113)
Returnable shares	—	—	113	—	—	—	113
Stock-based compensation expense	—		5	—	—	—	5
Total stockholders' deficit before comprehensive income (loss) items							(5,503)
Net loss	—	—	—	(1,765)	—	—	(1,765)
Gain on cash flow hedges before reclassification adjustment for cash flow hedges realized in net income	—	—	—	—	33	—	33
Reclassification adjustment for cash flow hedges realized in net loss	—	—	—	—	146	—	146
Provision for income taxes	—	—	—	—	(64)	—	(64)
Total comprehensive (loss)							(1,650)
Balance, December 31, 2006	$ 1	$ —	$ 3,270	$ (10,378)	$ (44)	$ (2)	$ (7,153)
Return of 50,000,000 shares of loaned common stock	—	—	(145)	—	—	—	(145)
Returnable shares	—	—	145	—	—	—	145
Stock-based compensation (income)	—	—	(7)	—	—	—	(7)
Total stockholders' deficit before comprehensive income (loss) items							(7,160)
Net income	—	—	—	2,693	—	—	2,693
Gain on cash flow hedges before reclassification adjustment for cash flow hedges realized in net income	—	—	—	—	(196)	—	(196)
Reclassification adjustment for cash flow hedges realized in net income	—	—	—	—	13	—	13
Foreign currency translation gain	—	—	—	—	—	12	12
Provision for income taxes	—	—	—	—	(14)	—	(14)
Total comprehensive income							2,508
Balance, December 31, 2007	$ 1	$ —	$ 3,263	$ (7,685)	$ (241)	$ 10	$ (4,652)
Cancellation of Calpine Corporation common stock	(1)	—	(3,263)	—	—	—	(3,264)
Issuance of reorganized Calpine Corporation common stock in accordance with the Plan of Reorganization	1	—	12,166	—	—	—	12,167
Treasury stock transactions	—	(1)	—	—	—	—	(1)
Stock-based compensation expense	—	—	50	—	—	—	50
Proceeds received from the exercise of warrants	—	—	1	—	—	—	1
Cumulative effect of adjustment from adoption of SFAS No. 157, net of tax of $8 million	—	—	—	(14)	—	—	(14)
Total stockholders' equity before comprehensive income (loss) items							4,287
Net income	—	—	—	10	—	—	10
Gain on cash flow hedges before reclassification adjustment for cash flow hedges realized in net income	—	—	—	—	141	—	141
Reclassification adjustment for cash flow hedges realized in net income	—	—	—	—	27	—	27
Foreign currency translation loss	—	—	—	—	—	(19)	(19)
Provision for income taxes	—	—	—	—	(76)	—	(76)
Total comprehensive income							83
Balance, December 31, 2008	$ 1	$ (1)	$ 12,217	$ (7,689)	$ (149)	$ (9)	$ 4,370

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

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
For the Years Ended December 31, 2008, 2007 and 2006

	2008	2007	2006
		(in millions)	
Cash flows from operating activities:			
Net income (loss)	$ 10	$ 2,693	$ (1,765)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization expense[1]	551	554	585
Deferred income taxes	(27)	(517)	22
Impairment charges	46	46	118
Gain on sale of discontinued operations	(37)	—	—
Loss on sale of assets, excluding reorganization items	36	31	36
Change in the fair value of derivative assets and liabilities	273	18	(72)
Derivative contracts classified as financing activities	(64)	—	—
Loss from unconsolidated investments in power plants	229	21	—
Stock-based compensation expense (income)	50	(1)	5
Reorganization items	(359)	(3,342)	807
Other	16	(2)	17
Change in operating assets and liabilities, net of effects of acquisitions:			
Accounts receivable	375	(194)	112
Other assets	(101)	(102)	49
Accounts payable, LSTC and accrued expenses	(215)	931	18
Other liabilities	(289)	51	80
Net cash provided by operating activities	494	187	12
Cash flows from investing activities:			
Purchases of property, plant and equipment	(143)	(196)	(212)
Proceeds from sale of power plants, turbines and investments	413	541	275
Proceeds from sale of discontinued operations	79	—	—
Cash acquired due to reconsolidation of Canadian Debtors and other foreign entities	64	—	—
Acquisitions, net of cash acquired	—	—	(267)
Contributions to unconsolidated investments	(17)	(68)	(59)
Return of investment from unconsolidated investments	27	179	—
Decrease in restricted cash	78	37	384
Cash effect of deconsolidation of VIEs	—	(29)	—
Other	15	9	37
Net cash provided by investing activities	516	473	158
Cash flows from financing activities:			
Repayments of notes payable and lines of credit	(99)	(135)	(180)
Borrowings from project financing	357	21	141
Repayments of project financing	(311)	(119)	(110)
Repayments of CalGen Secured Debt	—	(224)	—
Borrowings under DIP Facility	—	614	1,150
Repayments of DIP Facility	(98)	(38)	(179)
Borrowings under Exit Facilities	4,248	—	—
Repayments of Exit Facilities	(1,475)	—	—
Borrowings under Commodity Collateral Revolver	100	—	—
Repayments of Second Priority Debt	(3,672)	—	—
Proceeds from sale of ULC I bonds	—	151	—
Repayments and repurchases of First Priority Notes	—	—	(646)
Redemptions of preferred interests	(166)	(9)	(9)
Financing costs	(207)	(81)	(39)
Derivative contracts	64	—	—
Other	(9)	(2)	(7)
Net cash provided by (used in) financing activities	(1,268)	178	121
Net (decrease) increase in cash and cash equivalents	(258)	838	291
Cash and cash equivalents, beginning of period	1,915	1,077	786
Cash and cash equivalents, end of period	$ 1,657	$ 1,915	$ 1,077

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

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS — (Continued)

	2008	2007	2006
		(in millions)	
Cash paid (received) during the period for:			
Interest, net of amounts capitalized	$ 1,060	$ 1,143	$ 979
Income taxes	$ 74	$ 1	$ 9
Reorganization items included in operating activities, net	$ 120	$ 126	$ 120
Reorganization items included in investing activities, net	$ (418)	$ (582)	$ (107)
Reorganization items included in financing activities, net	$ —	$ 74	$ 39
Supplemental disclosure of non-cash investing and financing activities:			
Settlement of LSTC through issuance of reorganized Calpine Corporation common stock	$ 5,200	$ —	$ —
DIP Facility borrowings converted into exit financing under Exit Facilities	$ 3,872	$ —	$ —
Settlement of Convertible Senior Notes and Unsecured Senior Notes with reorganized Calpine Corporation common stock	$ 3,703	$ —	$ —
DIP Facility borrowings used to extinguish the Original DIP Facility principal $(989), CalGen Secured Debt principal $(2,309) and operating liabilities $(88)	$ —	$ 3,386	$ —
Project financing $(159) and operating liabilities $(33) extinguished with sale of Aries Power Plant	$ —	$ 192	$ —
Return of loaned common stock	$ —	$ 145	$ 113
Acquisition of property, plant and equipment for Geysers Assets, with offsets to operating assets	$ —	$ —	$ 181
Capital contribution (equipment) to Greenfield LP	$ —	$ —	$ 28
Letter of credit draws under the CalGen Secured Debt used for operating activities	$ —	$ 16	$ 71
Letter of credit collateral draws from restricted cash used for operating activities	$ —	$ —	$ 32
Letter of credit collateral draws from restricted cash used for minority interest distributions	$ —	$ —	$ 15
Fair value of Metcalf cooperation agreement, with offsets to notes payable $(6) and operating liabilities $(6)	$ —	$ 12	$ —
Restricted cash used for project financing debt repayments	$ —	$ —	$ 7
Project financing extinguished with sale of leasehold interest in the Fox Energy Center	$ —	$ —	$ 352

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

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

1. Organization and Operations

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

2. Summary of Significant Accounting Policies

Basis of Presentation and Principles of Consolidation

Our Consolidated Financial Statements have been prepared in accordance with GAAP and include the accounts of all majority-owned subsidiaries where we are the primary beneficiary. Intercompany transactions have been eliminated in consolidation. We record our net interest in VIEs, where we have determined that we are not the primary beneficiary and our net interest in less-than-majority-owned companies in which we exercise significant influence over operating and financial policies using the equity method of accounting. Accordingly, we report our equity in the net assets of these investments as a single-line item on our Consolidated Balance Sheets. Our share of net income (loss) is calculated according to our equity ownership or according to the terms of the appropriate partnership agreement. During 2008, we deconsolidated RockGen in January 2008 and Auburndale in August 2008, and subsequently reconsolidated RockGen in December 2008. During the second quarter of 2007, we deconsolidated OMEC. See Note 5 for further discussion of our VIEs.

Canadian Subsidiaries — As a result of filings by the Canadian Debtors under the CCAA in the Canadian Court, we deconsolidated most of our Canadian Debtors and other foreign entities as of December 20, 2005, the Petition Date, as we determined that the administration of the CCAA proceedings in a jurisdiction other than that of the U.S. Debtors' Chapter 11 cases resulted in a loss of the elements of control necessary for consolidation. Because of the uncertainty, as of the Petition Date, of our emergence from our CCAA and Chapter 11 cases, we fully impaired our investment in our Canadian and other foreign subsidiaries and accounted for such investments under the cost method. The impairment charge was included in reorganization items on our 2005 Consolidated Statement of Operations.

On February 8, 2008, the Canadian Effective Date, the Canadian Court ordered and declared that the proceedings under the CCAA were terminated. The termination of the proceedings of the CCAA and our emergence under the Plan of Reorganization allowed us to maintain our equity interest in the Canadian Debtors and other foreign entities, whose principal assets include various working capital items and a 50% ownership interest in Whitby, an equity method investment, net of debt. As a result, we regained control over our Canadian Debtors and other foreign entities which were reconsolidated into our Consolidated Financial Statements as of the Canadian Effective Date. See Note 3 for a further discussion on our emergence from Chapter 11.

We accounted for the reconsolidation under the purchase method in a manner similar to a step acquisition. The excess of the fair market value of the reconsolidated net assets over the carrying value of our investment balance of $0 amounted to approximately $107 million. We recorded the Canadian assets acquired and the liabilities assumed based on their estimated fair value, with the exception of Whitby. We reduced the fair value of our Whitby equity investment (approximately $62 million) to $0 and recorded the $71 million balance of the excess as a gain in reorganization items on our 2008 Consolidated Statement of Operations.

Reclassifications

Certain reclassifications have been made to prior periods to conform to the current year presentation. Specifically, our loss from unconsolidated investments in power plants was previously included with other operating expense. Additionally, the cash flows related to derivatives not designated as hedges are classified in operating activities on the Consolidated Statements of Cash Flows. Previously, these cash flows were classified within investing activities.

We elected on January 1, 2008, not to apply the netting provisions allowed under FSP FIN 39-1, "Amendment of FASB Interpretation No. 39." We have presented our derivative assets and liabilities on a gross basis as of December 31, 2008, on our Consolidated Balance Sheet in accordance with this standard. Adoption of this standard had no effect on our results of operations or cash flows. In accordance with FSP FIN 39-1, we retrospectively adjusted derivative assets and liabilities from a net to a gross basis on our Consolidated Balance Sheet as of December 31, 2007, to conform to the current period presentation. The effect on our Consolidated Balance Sheet as of December 31, 2007, was as follows (in millions) (only line items impacted are shown):

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

Use of Estimates in Preparation of Financial Statements

The preparation of financial statements in conformity with GAAP in the U.S. requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expense during the reporting period. Actual results could differ from those estimates.

Accounting for Reorganization

From the Petition Date through the Effective Date, our Consolidated Financial Statements were prepared in accordance with SOP 90-7 which requires that financial statements, for periods during the pendency of our Chapter 11 filings, to distinguish transactions and events that are directly associated with the reorganization from the ongoing operations of the business. Accordingly, certain income, expenses, realized gains and losses and provisions for losses that were realized or incurred in the Chapter 11 cases were recorded in reorganization items on our Consolidated Statements of Operations. In addition, pre-petition obligations impacted by the Chapter 11 cases were classified as LSTC on our Consolidated Balance Sheet at December 31, 2007, and reported at the amounts as confirmed in our Plan of Reorganization or expected to be allowed by the U.S. Bankruptcy Court, even if they may be settled for a lesser amount. In connection with our emergence from Chapter 11, we recorded certain "plan effect" adjustments to our Consolidated Balance Sheet as of the Effective Date in order to reflect certain provisions of our Plan of Reorganization. See Note 3 for a further discussion on our emergence from Chapter 11.

Impairment Evaluation of Long-Lived Assets, Including Intangibles and Investments

We evaluate our long-lived assets, such as property, plant and equipment, equity method investments, turbine equipment patents and specifically identifiable intangibles for impairment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. Examples of such events or changes in circumstances are:

- a significant decrease in the market price of a long-lived asset,
- a significant adverse change in the manner an asset is being used or its physical condition,
- an adverse action by a regulator or legislature or an adverse change in the business climate,
- an accumulation of costs significantly in excess of the amount originally expected for the construction or acquisition of an asset,
- a current-period loss combined with a history of losses or the projection of future losses, or
- a change in our intent about an asset from an intent to hold to a greater than 50% likelihood that an asset will be sold or disposed of before the end of its previously estimated useful life.

When we believe an impairment condition may have occurred, we are required to estimate the undiscounted future cash flows associated with a long-lived asset or group of long-lived assets at the lowest level for which identifiable cash flows are largely independent of the cash flows of other assets and liabilities for long-lived assets that are expected to be held and used. We evaluate our operating power plants as a whole. Equipment assigned to each power plant is not evaluated for impairment separately, as it is integral to the assumed future operations of the power plant to which it is assigned. All construction and development projects are reviewed for impairment whenever there is an indication of potential reduction in fair value. If it is determined that it is no longer probable that the projects will be completed and all capitalized costs will be recovered through future operations, the carrying values of the projects would be written down to the recoverable value.

In order to estimate future cash flows, we consider historical cash flows and changes in the market environment and other factors that may affect future cash flows. To the extent applicable, the assumptions we use are consistent with forecasts that we are otherwise required to make (for example, in preparing our other earnings forecasts). The use of this method involves inherent uncertainty. We use our best estimates in making these evaluations and consider various factors, including forward price curves for energy, fuel costs, and operating costs. However, actual future market prices and project costs could vary from the assumptions used in our estimates, and the impact of such variations could be material.

When we determine that our assets meet the assets held-for-sale criteria, they are reported at the lower of the carrying amount or fair value less the cost to sell.

If we determine that the undiscounted cash flows from an asset to be held and used are less than the carrying amount of the asset, or if we have classified an asset as held for sale, we must estimate fair value to determine the amount of any impairment charge.

Generally, fair value will be determined using valuation techniques such as the present value of expected future cash flows. We will also discount the estimated future cash flows associated with the asset using a single interest rate representative of the risk involved with such an investment. We may also consider prices of similar assets, consult with brokers, or employ other valuation techniques. We use our best estimates in making these evaluations and consider various factors, including forward price curves for energy, fuel costs, and operating costs. However, actual future market prices and project costs could vary from the assumptions used in our estimates, and the impact of such variations could be material.

We are also required to evaluate our equity method investments to determine whether or not they are impaired when the value is considered an "other than a temporary" decline in value. The evaluation and measurement of impairments for equity method investments involve the same uncertainties as described for long-lived assets that we own directly. Similarly, our estimates that we make with respect our equity and cost-method investments are subjective, and the impact of variations in these estimates could be material.

During 2008, we reviewed our power plants and determined that events and changes in circumstances indicated that impairment conditions may have occurred at our Auburndale Peaking Energy Center and our equity investment in Auburndale. Accordingly, we estimated fair values in accordance with our policy and determined that impairment charges were appropriate. The following table details impairment charges recorded during the years ended December 31, 2008, 2007 and 2006 (in millions):

	2008	2007	2006
Operating plant impairments	$ 33	$ 44	$ 53
Impairment of equity method investment[1]	180	—	—
Equipment, development project and other impairment charges[2]	13	2	65
Impairments included in reorganization items	—	120	—
Total impairment charges	$ 226	$ 166	$ 118

(1) Amounts are included in loss from unconsolidated investments in power plants on our Consolidated Statements of Operations.

(2) Amounts are included in other operating expense on our Consolidated Statements of Operations.

During the year ended December 31, 2008, we recorded an impairment charge of $180 million as a result of the anticipated sale of our investment in Auburndale as further described in Note 5. An additional impairment charge of $33 million was recorded at December 31, 2008, for our Auburndale Peaking Energy Center (a separate power plant from Auburndale) which did not receive an expected contract renewal resulting in reduced future expected cash flows. Additionally, we recorded impairments related to certain development projects that we determined were not probable of completion as of December 31, 2008. For the year ended December 31, 2007, we recorded operating plant impairment charges primarily related to the Bethpage Power Plant as additional competition due to new transmission lines reduced future expected cash flows and we recorded $120 million in reorganization items primarily related to the sale of our interest in Acadia PP. For the year ended December 31, 2006, we recorded operating plant impairment charges primarily related to operating plants that were sold during the year. Also during 2006, we recorded equipment, development project and other impairment charges primarily related to certain turbine-generator equipment not assigned to projects for which we determined near-term sales were likely.

Fair Value of Financial Instruments

The carrying value of accounts receivable, accounts payable and other payables approximate their respective fair values due to their short maturities. See Note 8 for disclosures regarding the fair value of our debt instruments.

Concentrations of Credit Risk

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

Cash and Cash Equivalents

We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents. The carrying amount of these instruments approximates fair value because of their short maturity. We have certain project finance facilities and lease agreements that establish segregated cash accounts. These accounts have been pledged as security in favor of the lenders to such project finance facilities, and the use of certain cash balances on deposit in such accounts with our project financed securities is limited, at least temporarily, to the operations of the respective projects. At December 31, 2008 and 2007, $296 million and $257 million, respectively, of the cash and cash equivalents balance that was unrestricted was subject to such project finance facilities and lease agreements.

Restricted Cash

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

The table below represents the components of our restricted cash as of December 31, 2008 and 2007 (in millions):

	2008			2007		
	Current	Non-Current	Total	Current	Non-Current	Total
Debt service	$ 102	$ 121	$ 223	$ 128	$ 111	$ 239
Rent reserve	34	—	34	11	—	11
Construction/major maintenance	72	18	90	62	26	88
Security/project reserves	96	1	97	119	—	119
Collateralized letters of credit and other credit support	7	1	8	4	—	4
Other	26	25	51	98	22	120
Total	$ 337	$ 166	$ 503	$ 422	$ 159	$ 581

Of our restricted cash at December 31, 2008 and 2007, $280 million and $304 million, respectively, relates to the assets of the following entities, each of which is an entity with its existence separate from us and our other subsidiaries (in millions).

	2008	2007
PCF	$ 159	$ 156
Gilroy Energy Center, LLC	35	36
Rocky Mountain Energy Center, LLC	29	44
Riverside Energy Center, LLC	33	34
King City Cogen	8	27
Metcalf[1]	15	6
PCF III	1	1
Total	$ 280	$ 304

(1) Metcalf was refinanced on June 10, 2008, and no longer qualifies as a special purpose subsidiary. See Note 8 for more information on the refinancing of Metcalf.

Accounts Receivable and Accounts Payable

Accounts receivable and payable represent amounts due from customers and owed to vendors. Accounts receivable are recorded at invoiced amounts, net of reserves and allowances, and do not bear interest. Receivable balances greater than 30 days past due are individually reviewed for collectibility, and if deemed uncollectible, are charged off against the allowance accounts after all means of collection have been exhausted and the potential for recovery is considered remote. We use our best estimate to determine the required allowance for doubtful accounts based on a variety of factors, including the length of time receivables are past due, economic trends and conditions affecting our customer base, significant one-time events and historical write-off experience. Specific provisions are recorded for individual receivables when we become aware of a customer's inability to meet its financial obligations. We review the adequacy of our reserves and allowances quarterly.

The accounts receivable and payable balances also include settled but unpaid amounts relating to marketing, hedging and optimization activities of CES. Some of these receivables and payables with individual counterparties are subject to master netting agreements whereby we legally have a right of setoff and we settle the balances net. However, for balance sheet presentation purposes and to be consistent with the way we present the majority of amounts related to marketing, hedging and optimization activities on our Consolidated Statements of Operations, we present our receivables and payables on a gross basis. We do not have any significant off balance sheet credit exposure related to our customers.

Counterparty Credit Risk

Our counterparties primarily consist of three categories of entities who participate in the wholesale energy markets: financial institutions and trading companies; regulated utilities, municipalities, cooperatives and other retail power suppliers; and oil, natural gas, chemical and other energy-related industrial companies. We have exposure to trends within the energy industry, including declines in the creditworthiness of our marketing counterparties. Currently, certain of our marketing counterparties within the energy industry have below investment grade credit ratings. Our risk control group manages counterparty credit risk and monitors our net exposure with each counterparty on a daily basis. The analysis is performed on a mark-to-market basis using forward curves. The net exposure is compared against a counterparty credit risk threshold which is determined based on each counterparty's credit rating and evaluation of their financial statements. We utilize these thresholds to determine the need for additional collateral or restriction of activity with the counterparty. We do not currently have any significant exposure to counterparties that are not paying on a current basis.

Inventory

Inventory primarily consists of spare parts, stored natural gas and oil, ERCs and natural gas exchange imbalances. Inventory, other than spare parts, is stated primarily at the lower of cost or market value under the weighted average cost method. Spare parts inventory is valued at weighted average cost and the costs are expensed to plant operating costs or capitalized to property, plant and equipment as the parts are utilized and consumed.

Collateral

We use margin deposits, prepayments and letters of credit as credit support with and from our counterparties for commodity procurement and risk management activities. In addition, we have granted additional liens on the assets currently subject to liens under the Exit Credit Facility to collateralize our obligations under certain of our power and natural gas agreements that qualify as "eligible commodity hedge agreements" under the Exit Credit Facility and certain of our interest rate swap agreements. See Note 11 for further information on our amounts and use of collateral.

Property, Plant and Equipment, Net

Property, plant, and equipment items are recorded at cost. We capitalize costs incurred in connection with the construction of power plants, the development of geothermal properties and the refurbishment of major turbine generator equipment. We expense annual planned maintenance when the service is performed. Depreciation, other than for geothermal properties, is primarily recorded utilizing the straight-line method over the estimated composite useful life, generally 35 years for our combined-cycle power plants, using an estimated salvage value which approximates 10% of the depreciable cost basis. Peaking, simple-cycle power plants are generally depreciated over 40 years, using an estimated salvage value of 10% of the depreciable cost basis. Certain capital improvements associated with leased power plants may be deemed to be leasehold improvements and are amortized over the shorter of the term of the lease or the economic life of the capital improvement.

Our current capital expenditures at the Geysers Assets are those incurred for proven reserves and reservoir replenishment (primarily water injection), pipeline and power generation assets and drilling of "development wells" as all drilling activity has been performed within the known boundaries of the steam reservoir. We have capitalized costs incurred during ownership consisting of additions, repairs or replacements when they appreciably extend the life, increase the capacity or improve the efficiency or safety of the property. Such costs are expensed when they do not meet the above criteria. We purchased the Geysers Assets as a proven steam reservoir and accounted for the assets under purchase accounting. All well costs have been capitalized since our purchase date as they have represented new development or services. Exploration activities are extremely limited and are not material to our overall capital expenditures or our fixed assets. We drilled one deep test well at Glass Mountain in 2001 which produced economically viable quantities of steam and the well costs were capitalized. Immaterial holding costs at Glass Mountain are expensed.

Depreciation for our Geysers Assets uses units-of-production depreciation. Beginning in 2008, we revised our units-of-production depreciation rate primarily as a result of extending the economic life from year 2034 to year 2050. Our units of production depletion rate is calculated using a depreciable base of the net book value of the Geysers Assets plus the expected future capital expenditures over the economic life of the geothermal reserves. The rate of depreciation per MWh is determined by dividing the depreciable base by total expected future generation (estimated units of proved reserves). Because our geothermal properties extract steam from one reservoir, we aggregate our Geysers Assets into one depreciable basis. Our Geysers Assets depreciation model is revised every year to include updates to anticipated future capital expenditures and estimated proved reserves. The new amortization rate is then applied to actual production to determine depreciation expense. We account for those revisions prospectively as changes in accounting estimates.

Generally, upon retirement or sale of property, plant, and equipment (other than geothermal), the costs of such assets and the related accumulated depreciation are removed from our Consolidated Balance Sheets and a gain or loss is recorded as a cost of revenue or other income item. However, under the units of production method for our Geysers Assets, replacement equipment is expensed when incurred unless it is a complete new operating system, in which case the replacement equipment is capitalized, and, upon retirement or sale of an entire power plant, its asset base and the related accumulated depreciation are removed from our Consolidated Balance Sheets. At times, geothermal equipment that is replaced over the normal course of business may be sold at market scrap value and proceeds recorded in other income on our Consolidated Statements of Operations.

Asset Retirement Obligation

We record all known asset retirement obligations for which the liability's fair value can be reasonably estimated. Over time, the liability is accreted to its present value each period and the capitalized cost is depreciated over the useful life of the related asset. At December 31, 2008 and 2007, our asset retirement obligation liabilities were $47 million and $39 million, respectively, primarily relating to land leases upon which our power plants are built and the requirement that the property meet specific conditions upon its return.

Revenue Recognition and Accounting for Commodity Derivative Instruments

Our operating revenues are composed of (i) power and steam revenue consisting of fixed capacity payments, which are not related to production, variable energy payments, which are related to production, host steam and thermal energy sales, and other revenues such as RMR Contracts, resource adequacy and certain ancillary service revenues, (ii) revenues from derivative instruments as a result of our marketing, hedging and optimization activities, and (iii) other service revenues including revenue related to the sales of combustion turbine component parts and services from TTS and PSM prior to their sale in September 2006 and March 2007, respectively.

Power and Steam

Physical Commodity Contracts — We recognize revenue primarily from the sale of power and steam, a by-product of some of our power production for sale to our customers for use in industrial or other heating operations upon transmission and delivery to the customer.

We also routinely enter into physical commodity contracts for sales of our generated power to manage risk and capture the value inherent in our generation. Such contracts often meet the criteria of a derivative but are generally eligible for the normal purchase normal sale exception. Certain other contracts do not meet the definition of a derivative and may be considered physical executory contracts or leases. We apply lease or traditional accrual accounting to these contracts that are exempt from derivative accounting or do not meet the definition of a derivative instrument. Additionally, we determine whether the financial statement presentation of revenues should be on a gross or net basis.

With respect to our physical executory contracts, where we act as a principal, we take title of the commodities and assume the risks and rewards of ownership by receiving the natural gas and using the natural gas in our operations to generate and deliver the power. Where we act as principal, we record settlement of our physical commodity contracts on a gross basis. With respect to our physical executory contracts, where we do not take title of the commodities but receive a variable energy payment to convert natural gas into power and steam in a tolling operation, we record revenues on a net basis. Our physical commodity contracts are not entered into for the purpose of settling on a net basis with another counterparty.

RMR Contracts, resource adequacy and other ancillary revenues are recognized when contractually earned and consist of revenues received from our customer either at the market price or a contract price.

Leases — Contracts accounted for as operating leases with minimum lease rentals which vary over time must be levelized. Generally, we levelize these contract revenues on a straight-line basis over the term of the contract.

The total contractual future minimum lease receipts for these contracts are as follows (in millions):

2009	$ 151
2010	153
2011	156
2012	158
2013	146
Thereafter	909
Total	$ 1,673

Derivative Instruments (Marketing, Hedging and Optimization)

We enter into a variety of derivative instruments to include both exchange traded and OTC power and natural gas forwards, options as well as instruments that settle on the power price to natural gas price relationships (Heat Rate swaps and options) and interest rate swaps. The majority of this activity is related to the fuel and power price risk associated with our generation assets and our contractual obligations. We recognize all derivative instruments that qualify for derivative accounting treatment as either assets or liabilities and measure those instruments at fair value unless they qualify for the normal purchase normal sale exemption.

Hedge Accounting — Revenues derived from marketing, hedging and optimization that qualify for hedge accounting are recorded on a net basis in the period that the hedged item is recognized into earnings. Hedge accounting requires us to formally document, designate and assess the effectiveness of transactions that receive hedge accounting. For revenues derived from marketing, hedging and optimization contracts that do not qualify for hedge accounting treatment and for certain forward physical PPAs that do not qualify for the normal purchase normal sale exemption under derivative accounting, revenues are recognized currently into earnings as mark-to-market activity.

Accounting for derivatives at fair value requires us to make estimates about future prices during periods for which price quotes are not available from sources external to us, in which case we rely on internally developed price estimates. During periods where external price quotes are unavailable, we derive such future price estimates based on an extrapolation of prices from periods where external price quotes are available. We perform this extrapolation using liquid and observable market prices and extending those prices to an internally generated long-term price forecast based on a generalized equilibrium model.

We report the effective portion of the gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument as a component of OCI and reclassify such gains and losses into earnings in the same period during which the hedged forecasted transaction affects earnings. The remaining gain or loss on the derivative instrument, if any, must be recognized currently in earnings. Changes in fair value of derivatives designated as fair value hedges and the corresponding changes in the fair value of the hedged risk attributable to a recognized asset or liability, or unrecognized firm commitment is recorded in earnings. If the fair value hedge is effective, the amounts recorded will be offset in earnings.

With respect to cash flow hedges, if it is determined that the forecasted transaction is no longer probable of occurring, then hedge accounting will be discontinued prospectively and the associated gain or loss previously deferred in OCI is reclassified into current income. If the hedging instrument is terminated or de-designated prior to the occurrence of the hedged forecasted transaction, the gain or loss associated with the hedge instrument remains deferred in OCI until such time as the forecasted transaction impacts earnings, or until it is determined that the forecasted transaction is no longer probable of occurring.

With respect to fair value hedges, if the underlying asset, liability or firm commitment being hedged is disposed of or otherwise terminated, the gain or loss associated with the underlying hedged item is recognized currently in earnings. If the hedging instrument is terminated or de-designated prior to the settlement of the hedged asset, liability or firm commitment, the adjustment of the carrying amount of the hedged item would remain until the hedged item is recognized in earnings.

We present the cash flows from our derivatives in the same category as the item being hedged within operating activities on our Consolidated Statements of Cash Flows unless they contain an other-than-insignificant financing element in which case their cash flows are classified within financing activities.

Mark-to-Market Activity — A component of operating revenues (for power contracts), fuel and purchased energy expense (for natural gas contracts) and interest expense (for interest rate swaps), includes realized settlements and unrealized mark-to-market gains and losses resulting from general market price movements on power, natural gas and interest rate swap derivative instruments not designated or not qualifying as cash flow hedges. Gains and losses due to ineffectiveness on commodity hedging instruments are also included in unrealized mark-to-market gains and losses.

Fuel and Purchased Energy Expense

Fuel and purchased energy expense is composed of the cost of natural gas purchased from third parties for the purposes of consumption in our power plants as fuel expense and the cost of power and natural gas purchased from third parties for marketing, hedging and optimization activities as well as unrealized mark-to-market gains and losses resulting from general market price movements against certain derivative natural gas contracts that do not qualify for hedge accounting treatment.

Plant Operating Expense

We recognize expense when the service is performed. Plant operating expense primarily includes employee expenses, repairs and maintenance, insurance and property taxes.

Income Taxes

Income taxes are accounted for under the asset and liability method. Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying values of existing assets and liabilities and their respective tax bases and tax credit and NOL carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date.

We recognize the financial statement effects of a tax position when it is more likely than not, based on the technical merits, that the position will be sustained upon examination. A tax position that meets the more-likely-than-not recognition threshold is measured as the largest amount of tax benefit that is greater than 50% likely of being realized upon ultimate settlement with a taxing authority. We reverse a previously recognized tax position in the first period in which it is no longer more-likely-than-not that the tax position would be sustained upon examination.

Earnings (Loss) per Share

Basic earnings (loss) per share is calculated using the average actual shares outstanding during the period. Diluted earnings (loss) per share is calculated by adjusting the average actual shares outstanding by the dilutive effect of restricted common stock and unexercised in-the-money stock options, using the treasury stock method, and assumes that convertible securities were converted into common stock upon issuance, if dilutive.

In accordance with applicable accounting standards, entities that have entered into a forward contract that requires physical settlement by repurchase of a fixed number of the issuer's equity shares of common stock in exchange for cash shall exclude the common shares to be redeemed or repurchased when calculating basic and diluted EPS. Our share lending agreement, which terminated in 2007 upon the return to us of all the loaned shares, did not provide for cash settlement, but rather physical settlement was required (i.e., the shares had to be and were returned by the end of the arrangement). Consequently, the loaned shares of common stock subject to the share lending agreement were excluded from our EPS calculation for the years ended December 31, 2007 and 2006. See Note 15 for a discussion of the share lending agreement.

Stock-Based Compensation

On January 1, 2006, we transitioned from SFAS No. 123 "Accounting for Stock-Based Compensation" to SFAS No. 123(R), "Share-Based Payment" and applied the modified prospective transition method. SFAS No. 123(R) requires us to recognize our stock-based compensation based on grant date fair value and present the cash flows resulting from the tax benefits that occur from estimated tax deductions in excess of the compensation cost recognized as financing cash flows in the Statement of Cash Flows to the unvested portion of all awards granted prior to January 1, 2006, and to all prospective awards.

We have selected the Black-Scholes option-pricing model to estimate the fair value of our employee stock options, or its equivalent, on the grant date. The Black-Scholes option-pricing model takes into account certain variables, which are explained further in Note 13.

New Accounting Pronouncements

SFAS No. 157

In September 2006, FASB issued SFAS No. 157, "Fair Value Measurements," which is effective for fiscal years beginning after November 15, 2007, and for interim periods within those years. SFAS No. 157 defines fair value, establishes a framework for measuring fair value under GAAP and enhances disclosures about fair value measurements. SFAS No. 157 applies when other accounting pronouncements require fair value measurements; it does not require any new fair value measurements. In February 2008, FASB issued FSP No. FAS 157-2, "Effective Date of FASB Statement No. 157," which defers the effective date of SFAS No. 157 for non-financial assets and liabilities, except those that are recognized or disclosed at fair value in the financial statements on a recurring basis (at least annually), until fiscal years and interim periods beginning after November 15, 2008. We have certain potential non-recurring, non-financial assets and non-financial liabilities recorded at fair value that fall within the scope of FSP No. FAS 157-2 that include asset retirement obligations initially measured at fair value and long-lived assets measured at fair value for impairment testing. We adopted SFAS No. 157 for non-financial assets and non-financial liabilities as of January 1, 2009, and do not expect this standard to have a material impact on our future results of operations, cash flows or financial position. We adopted SFAS No. 157 as of January 1, 2008, related to financial assets and financial liabilities. See Note 10 for a discussion of the impact of adopting this standard.

SFAS No. 141(R)

In December 2007, FASB issued SFAS No. 141(R), "Business Combinations," which replaces SFAS No. 141. SFAS No. 141(R) establishes principles and requirements for how the acquirer in a business combination recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed and any noncontrolling interest in the acquiree. In addition, SFAS No. 141(R) recognizes and measures the goodwill acquired in the business combination or a gain from a bargain purchase. SFAS No. 141(R) also establishes disclosure requirements to enable users to evaluate the nature and financial effects of the business combination. SFAS No. 141(R) is effective as of the beginning of an entity's fiscal year that begins after December 15, 2008, with early adoption prohibited. We do not expect this standard to have a material impact on our results of operations, cash flows or financial position.

SFAS No. 160

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

SFAS No. 161

In March 2008, FASB issued SFAS No. 161, "Disclosures about Derivative Instruments and Hedging Activities — An Amendment of FASB Statement No. 133." SFAS No. 161 requires enhanced disclosures about an entity's derivative and hedging activities to enable investors to better understand their effects on the entity's financial position, financial performance, and cash flows. SFAS No. 161 is effective for fiscal years and interim periods beginning after November 15, 2008, with early adoption encouraged. Since SFAS No. 161 requires only additional disclosures regarding derivatives and hedging activities and does not impact accounting entries, we do not expect this standard to have a material impact on our results of operations, cash flows or financial position.

FASB Staff Position No. FAS 133-1 and FIN 45-4

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

FASB Staff Position No. FAS 157-3

As a result of the recent credit crisis, on October 10, 2008, FASB issued FSP No. FAS 157-3, "Determining the Fair Value of a Financial Asset in a Market That is Not Active." This FSP clarifies the application of SFAS No. 157 "Fair Value Measurements," in a market that is not active. The FSP addresses how management should consider measuring fair value when relevant observable data does not exist. The FSP also provides guidance on how observable market information in a market that is not active should be considered when measuring fair value, as well as how the use of market quotes should be considered when assessing the relevance of observable and unobservable data available to measure fair value. This FSP is effective upon issuance, including prior periods for which financial statements have not been issued. Revisions resulting from a change in the valuation technique or its application shall be accounted for as a change in accounting estimate in accordance with SFAS No. 154, "Accounting Changes and Error Corrections." Adoption of this standard resulted in a clarification of existing accounting guidance with no change to our accounting policies and had no effect on our results of operations, cash flows or financial position. See Note 10 for a further discussion of our fair value measurements.

FASB Staff Position No. FAS 140-4 and FIN 46(R)-8

In December 2008, FASB issued FSP No. FAS 140-4 and FIN 46(R)-8, "Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interest in Variable Interest Entities." FSP FAS 140-4 and FIN 46(R)-8 requires additional disclosures about transfers of financial assets and variable interests in qualifying special purpose entities. This FSP also requires public enterprises to provide additional disclosures about their involvement with VIEs. These additional disclosures are intended to provide enhanced transparency to financial statement users about a transferor's ongoing involvement with transferred financial assets and an enterprise's involvement with VIEs and qualifying special purpose entities. FSP No. FAS 140-4 and FIN 46(R)-8 is effective for the first reporting period (interim or annual) ending after December 15, 2008, with early adoption encouraged. Adoption of this standard had no material effect on our results of operations, cash flows or financial position. See Note 5 for a further discussion of our involvement and required disclosures related to our VIEs.

3. Our Emergence from Chapter 11

Summary of Proceedings

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

During the pendency of our Chapter 11 cases through the Effective Date, pursuant to automatic stay provisions under the Bankruptcy Code and orders granted by the Canadian Court, all actions to enforce or otherwise effect repayment of liabilities preceding the Petition Date as well as all pending litigation against the Calpine Debtors generally were stayed. Following the Effective Date, actions to enforce or otherwise effect repayment of liabilities preceding the Petition Date, as well as pending litigation against the Calpine Debtors related to such liabilities generally have been permanently enjoined. Any unresolved claims will continue to be subject to the claims reconciliation process under the supervision of the U.S. Bankruptcy Court. However, certain pending litigation related to pre-petition liabilities may proceed in courts other than the U.S. Bankruptcy Court to the extent the parties to such litigation have obtained relief from the permanent injunction.

Plan of Reorganization — On June 20, 2007, the U.S. Debtors filed the Debtors' Joint Plan of Reorganization and related Disclosure Statement, which were subsequently amended on each of August 27, September 18, September 24, September 27 and December 13, 2007. On December 19, 2007, we filed the Sixth Amended Joint Plan of Reorganization. As a result of the modifications to the Plan of Reorganization as well as settlements reached by stipulation with certain creditors, all classes of creditors entitled to vote ultimately voted to approve the Plan of Reorganization. The Plan of Reorganization, which provides that the total enterprise value of the reorganized U.S. Debtors for purposes of the Plan of Reorganization is $18.95 billion, also provided for the amendment and restatement of our certificate of incorporation and the adoption of the Calpine Equity Incentive Plans. The Plan of Reorganization was confirmed by the U.S. Bankruptcy Court on December 19, 2007, and became effective on January 31, 2008. The Plan of Reorganization provides for the treatment of claims against and interests in the U.S. Debtors. Pursuant to the Plan of Reorganization:

- Allowed administrative claims as well as first and second lien debt claims have been or are being paid in full in cash and cash equivalents;

- Priority tax claims have been or are being paid in full in cash and cash equivalents or with a distribution of the reorganized Calpine Corporation common stock;

- Other allowed secured claims have been or are being reinstated, paid in full in cash or cash equivalents, or had the collateral securing such claims returned to the secured creditor;

- Make whole claims arising in connection with the repayment of the CalGen Second Lien Debt pursuant to the settlement described below and the CalGen Third Lien Debt that are ultimately allowed can be paid using cash and cash equivalents generated from the sale of the allowed claim or with cash and cash equivalents on hand. To the extent that the common stock reserved on account for such make whole claims is insufficient in value to satisfy such claims in full, we must use other available cash to satisfy such claims unless otherwise approved by the U.S. Bankruptcy Court;

- Allowed unsecured claims have received or will receive a pro rata distribution of all reorganized Calpine Corporation common stock issued under the Plan of Reorganization (except shares reserved for issuance under the Calpine Equity Incentive Plans);

- Allowed unsecured convenience claims (subject to certain exceptions, all unsecured claims $50,000 or less) have been or are being paid in full in cash or cash equivalents;

- Holders of allowed interests in Calpine Corporation (primarily holders of Calpine Corporation common stock existing as of the Petition Date) received a pro rata share of warrants to purchase approximately 48.5 million shares of reorganized Calpine Corporation common stock, subject to certain terms including exercise by August 25, 2008; and

- Holders of subordinated equity securities claims did not receive a distribution under the Plan of Reorganization and may only recover from applicable insurance proceeds.

Pursuant to the Plan of Reorganization, all shares of our common stock outstanding prior to the Effective Date were canceled, and the issuance of 485 million shares of reorganized Calpine Corporation common stock was authorized. Through the filing of this Report, approximately 427 million shares have been distributed to holders of allowed unsecured claims against the U.S. Debtors, approximately 10 million shares are being held pending resolution of certain inter-creditor matters and approximately 48 million shares remain in reserve for distribution to holders of disputed claims whose claims ultimately become allowed. We estimate that the number of shares reserved is sufficient to satisfy the U.S. Debtors' obligations under the Plan of Reorganization even if all disputed unsecured claims ultimately become allowed. As disputed claims are resolved, the claimants receive distributions of shares from the reserve on the same basis as if such distributions had been made on or about the Effective Date. To the extent that any of the reserved shares remain undistributed upon resolution of the remaining disputed claims, such shares will not be returned to us but rather will be distributed pro rata to claimants with allowed claims to increase their recovery. We are not required to issue additional shares above the 485 million shares authorized to settle unsecured claims, even if the shares remaining for distribution are not sufficient to fully pay all allowed unsecured claims. Accordingly, resolution of these claims could have a material effect on creditor recoveries under the Plan of Reorganization as the total number of shares of common stock that remain available for distribution upon resolution of disputed claims is limited pursuant to the Plan of Reorganization. Additionally, certain disputed claims, including prepayment premium and default interest claims asserted by the holders of CalGen Third Lien Debt, have not yet been finally adjudicated and may be required to be settled in cash and cash equivalents or reorganized Calpine Corporation common stock held in reserve pursuant to the Plan of Reorganization. To the extent that the common stock reserved on account for such make whole claims is insufficient in value to satisfy such claims in full, we must use other available cash to satisfy such claims unless otherwise approved by the U.S. Bankruptcy Court. No assurances can be given that settlements may not be materially higher or lower than confirmed in the Plan of Reorganization or than we originally estimated.

On September 22, 2008, the U.S. Bankruptcy Court approved our settlement with the holders of the CalGen Second Lien Debt settling their claims asserted in our Chapter 11 cases for, among other things, prepayment premiums and default interest for $64 million plus interest accruing from September 30, 2008. Pursuant to the settlement, unsecured claims to the holders of the CalGen Second Lien Debt were allowed in the aggregate amount of $110 million. These unsecured claims were satisfied with distributions of 5,358,300 shares of the reorganized Calpine Corporation common stock reserved under the Plan of Reorganization.

Certain disputed make whole claims, including prepayment premium and default interest claims asserted by the holders of CalGen Third Lien Debt, have not yet been finally adjudicated. To the extent that the common stock reserved on account for such make whole claims is insufficient in value to satisfy such claims in full, we must use other available cash to satisfy such claims unless otherwise approved by the U.S. Bankruptcy Court. No assurances can be given that settlements may not be materially higher or lower than confirmed in the Plan of Reorganization or than we originally estimated.

Pursuant to the Plan of Reorganization, we were also authorized to issue up to 15 million shares under the Calpine Equity Incentive Plans, and, as of December 31, 2008, approximately 2 million shares of restricted stock, net of forfeitures, and options to purchase approximately 9 million shares of common stock, net of forfeitures, had been issued under the Calpine Equity Incentive Plans. Holders of allowed interests in Calpine Corporation (primarily holders of Calpine Corporation common stock existing as of the Petition Date) received a pro rata share of warrants to purchase approximately 48.5 million shares of reorganized Calpine Corporation common stock at $23.88 per share. Warrants for 21,499 shares of common stock were exercised prior to expiration. The remaining unexercised warrants expired on August 25, 2008. Proceeds received of approximately $1 million from the exercise of the warrants were recorded as additional paid-in capital.

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

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

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

CCAA Proceedings — Upon the application of the Canadian Debtors and other foreign entities, on February 8, 2008, the Canadian Court ordered and declared that (i) the unsecured notes issued by ULC I were canceled and discharged on February 4, 2008, (ii) the Canadian Debtors had completed all distributions previously ordered in full satisfaction of the pre-filing claims against them, (iii) the Canadian Debtors had otherwise fully complied with all orders of the Canadian Court and (iv) the proceedings under the CCAA were terminated, including the stay of proceedings.

Applicability of Fresh Start Accounting

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

U.S. Debtors Condensed Combined Financial Statements

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

Condensed combined financial statements of the U.S. Debtors are set forth below (in millions):

Condensed Combined Balance Sheets
As of December 31, 2007

	2007
Assets:	
Current assets	$ 5,624
Restricted cash, net of current portion	35
Investments	2,604
Property, plant and equipment, net	6,862
Other assets	998
Total assets	$ 16,123
Liabilities not subject to compromise:	
Current liabilities	$ 3,220
Long-term debt	6,789
Long-term derivative liabilities	416
Other liabilities	292
Liabilities subject to compromise	10,510
Stockholders' deficit	(5,104)
Total liabilities and stockholders' deficit	$ 16,123

Condensed Combined Statements of Operations
For the Years Ended December 31, 2007 and 2006

	2007	2006
Total revenue	$ 7,440	$ 5,990
Total cost of revenue	7,174	5,795
Operating (income) expense[(1)]	(39)	200
Income (loss) from operations	305	(5)
Interest expense	1,606	795
Other (income) expense, net	(118)	—
Reorganization items, net	(3,240)	900
Income (loss) before income taxes	2,057	(1,700)
(Benefit) provision for income taxes	(346)	100
Net income (loss)	$ 2,403	$ (1,800)

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

Condensed Combined Statements of Cash Flows
For the Years Ended December 31, 2007 and 2006

	2007	2006
Net cash provided by (used in):		
Operating activities	$ (93)	$ (183)
Investing activities	504	291
Financing activities	404	265
Net increase in cash and cash equivalents	815	373
Cash and cash equivalents, beginning of period	883	444
Effect on cash of new debtor filings	—	66
Cash and cash equivalents, end of period	$ 1,698	$ 883
Net cash paid for reorganization items included in operating activities	$ 126	$ 120
Net cash received from reorganization items included in investing activities	$ (576)	$ (103)
Net cash paid for reorganization items included in financing activities	$ 74	$ 39

Interest Expense — We recorded $135 million in post-petition interest from January 1, 2008, through the Effective Date. As our Plan of Reorganization was confirmed on December 19, 2007, we recorded interest expense in December 2007 for allowed claims under the Plan of Reorganization of $347 million related to post-petition interest on LSTC incurred from the Petition Date through December 31, 2007. This amount represents non-cash value to be satisfied through distributions of shares of Calpine Corporation's reorganized common stock. Prior to recording the post-petition interest on LSTC in December 2007, interest expense related to pre-petition LSTC was reported only to the extent that it was paid during the pendency of the Chapter 11 cases or was permitted by the Cash Collateral Order or other orders of the U.S. Bankruptcy Court. Contractual interest (at non-default rates) owed to unrelated parties on pre-petition LSTC not reflected on our Consolidated Financial Statements was $157 million and $273 million for the years ended December 31, 2007 and 2006, respectively, and $18 million for the period from the Petition Date through December 31, 2005. Additionally, we made 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. Upon confirmation of our Plan of Reorganization, the obligations to the holders of the Second Priority Debt were fully satisfied. Therefore, we have reported the full amount of the adequate protection payments as interest expense on our Consolidated Statements of Operations together with the remaining contractual interest through December 31, 2007, on the Second Priority Debt.

Reorganization Items — Reorganization items represent the direct and incremental costs related to our Chapter 11 cases, such as professional fees, pre-petition liability claim adjustments and losses that are probable and can be estimated, net of interest income earned on accumulated cash during the Chapter 11 process and net gains on the sale of assets or resulting from certain settlement agreements related to our restructuring activities. Our restructuring activities may result in additional charges and other adjustments for expected allowed claims (including claims that may be subsequently 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 years ended December 31, 2008, 2007 and 2006 (in millions):

	2008	2007	2006
Provision for expected allowed claims	$ (95)	$ (3,687)	$ 845
Professional fees	85	217	153
Gains on asset sales	(206)	(285)	(106)
Asset impairments	—	120	—
Gain on reconsolidation of Canadian Debtors and other foreign entities	(71)	—	—
DIP Facility and Exit Facilities financing and CalGen Secured Debt repayment costs	(4)	202	39
Interest (income) on accumulated cash	(7)	(59)	(25)
Other	(4)	234	66
Total reorganization items	$ (302)	$ (3,258)	$ 972

Provision for Expected Allowed Claims — Represents the change in our estimate of the expected allowed claims. During the year ended December 31, 2008, our provision for expected allowed claims consisted primarily of a $62 million credit related to the settlement of claims with the Canadian Debtors, a $12 million credit related to our settlement with Rosetta and a $34 million credit for RockGen from a prior period which we determined was not material to any period. During the year ended December 31, 2007, our provision for expected allowed claims consisted primarily of a credit of $4.1 billion resulting from the Canadian Settlement Agreement.

Gains on Asset Sales — Represents gains on the sales of the Hillabee and Fremont development project assets for the year ended December 31, 2008. See Note 7 for further discussion of our sales of Hillabee and Fremont. The sales of these assets and utilization of the sales proceeds to repay the Bridge Facility were part of our Plan of Reorganization and are included in reorganization items even though the sales closed subsequent to the Effective Date. The amounts recorded for the year ended December 31, 2007, primarily represent the gains recorded on the sales of the assets of MEP Pleasant Hill, LLC (consisting primarily of the Aries Power Plant), Goldendale Energy Center and PSM.

Asset Impairments — Impairment charges for the year ended December 31, 2007, primarily relate to recording our interest in Acadia PP at fair value less costs to sell.

Other — Other reorganization items consist primarily of adjustments for foreign exchange rate changes on LSTC denominated in a foreign currency and governed by foreign law, employee severance and emergence incentive costs during the years ended December 31, 2008, 2007 and 2006.

Liabilities Subject to Compromise

The amounts of LSTC at December 31, 2007, consisted of the following (in millions):

	2007
Provision for expected allowed claims[1]	$ 4,398
Unsecured Senior Notes	1,880
Convertible Senior Notes	1,824
Accounts payable and accrued liabilities	686
Total liabilities subject to compromise[2]	$ 8,788

(1) The remaining balance in the provision for expected allowed claims at December 31, 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, the results of other approved settlements and miscellaneous accruals for expected allowed claims. The provision for expected allowed claims was adjusted during the year ended December 31, 2007, to record the effects of the Canadian Settlement Agreement.

(2) As a result of our Confirmation of our Plan of Reorganization and emergence from Chapter 11 on the Effective Date, we believe that the amounts recorded as LSTC as of December 31, 2007, approximated fair value. However, there remain unresolved settlements of disputed claims, including litigation instituted by us challenging so-called "make whole" premium, or "no-call" claims that continued past the Effective Date. No assurances can be given that settlements may not be materially higher or lower than we estimated as of December 31, 2007.

4. Property, Plant and Equipment, Net

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

	2008	2007
Buildings, machinery, and equipment	$ 13,360	$ 13,439
Geothermal properties	979	944
Other	258	259
	14,597	14,642
Less: Accumulated depreciation	(2,932)	(2,582)
	11,665	12,060
Land	76	77
Construction in progress	167	155
Property, plant and equipment, net	$ 11,908	$ 12,292

Total depreciation expense for the years ended December 31, 2008, 2007 and 2006 was $437 million, $472 million and $484 million, respectively.

We have various debt instruments that are collateralized by certain of our property, plant and equipment. See Note 8 for a detailed discussion of such instruments.

Buildings, Machinery and Equipment

This component primarily includes power plants and related equipment. Included in buildings, machinery and equipment are assets under capital leases. See Note 8 for further information regarding these assets under capital leases.

Other

This component primarily includes oil and natural gas pipeline assets, software and ERCs that are plant specific and not available to be sold.

Capitalized Interest

The total amount of interest capitalized was $20 million for the year ended December 31, 2008, and $26 million for each of the years ended December 31, 2007 and 2006.

5. Variable Interest Entities and Unconsolidated Investments

As disclosed in Note 2, we adopted the disclosure requirements under newly issued FSP No. FAS 140-4 and FIN 46(R)-8, "Disclosures by Public Entities (Enterprises) about Transfers of Financial Assets and Interest in Variable Interest Entities."

VIE Consolidation Policy — We consolidate all VIEs where we are the primary beneficiary. This determination is made at the inception of our involvement with the VIE. We consider both qualitative and quantitative factors and form a conclusion that we, or another interest holder, absorbs a majority of the entity's risk for expected losses, receive a majority of the entity's potential for expected residual returns, or both.

Making these determinations can require the use of significant judgment, both on a qualitative and quantitative basis, which include, but are not limited to:

- Consideration of the design of the VIE, its purpose and variability it is designed to create and pass along to its interest holders;
- Preparation of future expected financial results and future expected cash flows from the VIE;
- Assigning probabilities to future events, markets and potential outcomes, such as the exercise of purchase options;
- Estimates in future residual fair values of power plant assets years into the future; and
- Determinations of our counterparties' reasons and intentions for entering into the VIE.

If we determine that we will absorb a majority of a VIE's expected losses, receive a majority of the entity's potential for expected residual returns or both, we consolidate the VIE in accordance with GAAP into our Consolidated Financial Statements. We re-evaluate our initial determination that consolidation is appropriate only when a reconsideration event occurs. Examples of reconsideration events include, but are not limited to:

- The primary beneficiary sells or otherwise disposes of all or part of its variable interests to unrelated parties;
- The VIE issues new variable interests to parties other than the primary beneficiary or the primary beneficiary's related parties; and
- The entity's governing documents or contractual arrangements are changed in a manner that reallocates between the existing primary beneficiary and other unrelated parties (a) the obligation to absorb the expected losses of the VIE or (b) the right to receive the expected residual returns of the VIE.

Our consolidated VIEs are aggregated into the following classifications in order of priority:

- Subsidiaries that contain either a put or call option with third parties to purchase all or a portion of our interest in a power plant or its cash flows;
- Subsidiaries that have subordinated and/or project debt;
- Subsidiaries with PPAs; and
- Other subsidiaries that represent a VIE.

Below is a description of our VIEs that we consolidate. In instances where the VIE may have characteristics of more than one aggregate classification, we have included it in the classification that is determined by us to be the most significant.

Consolidated VIEs with a Purchase or Sale Option

Certain of our subsidiaries have PPAs or other agreements that provide us the right to require third parties or provides the third parties the option to purchase power plant assets named in the agreement, an equity interest in a named generating asset, or a portion of the future cash flows generated from the asset. For these VIEs, we determined at the time we entered into the contractual arrangement giving rise to the purchase or sale option whether consolidation was appropriate for one or more of the following reasons:

- Exercise of the option by the other interest holder is unlikely based upon the expected value of the power plant assets;
- Exercise of the option requires an event of default related to the contract or agreement; which is unlikely;
- Exercise of the option only allows for a minority interest in the equity or future cash flows from the power plant assets and we retain the primary risk of loss.

Consolidated Subsidiaries with Subordinated and/or Project Debt

Certain of our subsidiaries have project debt that contains provisions which we have determined create variability. Our construction/project financings are collateralized solely by the capital stock or partnership interests, physical assets, contracts and/or cash flows attributable to the entities that own the power plants. Certain of our subsidiaries with subordinated and/or project debt limits transfers of assets or have certain restrictions on the transferability of cash. See Note 2 for a detail of our restricted cash balances. The lender has a priority interest in the cash flows of the project during the repayment period. However, our risk of loss and the lender's recourse under these project financings is limited to such collateral. We determined that we are the primary beneficiary at the inception of our involvement with the VIE because these projects are under contract during the repayment period and repayment is expected. Exercise of control by the lender can occur only in the event of default or under limited circumstances, which we have determined to be unlikely. In addition, we retain ownership and absorb the full risk of loss and potential for reward once the project debt is paid in full. See Note 8 for further information regarding our subordinated and/or project debt.

Consolidated Subsidiaries with PPAs

Certain of our 100% owned consolidated subsidiaries have PPAs that may serve to transfer the risk of loss of the entity and thus constitute a VIE based upon the involvement of the counterparty. For all such VIEs we have determined that we are the primary beneficiary at the inception of the VIE as exercise of control by the counterparty can occur only in the event of default or under limited circumstances, which we have determined to be unlikely. Additionally, we retain ownership and absorb the majority of the risk of loss and potential for reward during the term of the PPA and full risk of loss and potential for reward once the PPAs expire.

Other Consolidated VIEs

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

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

Condensed Combined VIE Assets and Liabilities

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

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

Unconsolidated VIEs and Investments

We do not consolidate VIEs where we have determined that we are not the primary beneficiary. Our unconsolidated investments in VIEs consist of our subsidiaries with purchase option rights where we have determined, at the inception of our involvement of the VIE, that we are not the primary beneficiary. We also have joint venture and equity interests where we do not demonstrate significant control and thus, we are not the primary beneficiary of the joint venture or equity interest. We account for these unconsolidated VIEs, joint venture and equity interests under the equity method of accounting and include our net equity interest in investments on our Consolidated Balance Sheets. Our equity interest in the net income from our unconsolidated VIEs is recorded in loss from unconsolidated investments in power plants on a net basis.

Inland Empire Energy Center Put Option — In July 2005, we sold the Inland Empire Energy Center development project (a 775 MW Cogeneration facility located in California) to GE. As of December 31, 2008, Inland Empire has yet to achieve COD. As a component to the sales agreement, we hold a call option to purchase the project, at predetermined prices based on the date the option is exercised. Should we not exercise the call option, GE holds a put option whereby they can require us to purchase the project, if certain plant performance criteria are met. Analysis was completed to determine whether we were the primary beneficiary of the Inland Empire facility upon execution of the arrangement. We determined that we were not the primary beneficiary of the Inland Empire project as we do not absorb the majority of the risk of loss associated with the project through holding the call option to purchase the project. This conclusion is reached through consideration of factors including, but not limited to, the fact that GE will manage and fully fund the construction effort of the project, and upon reaching COD manage and operate the project. Additionally, if we purchase the project under the call or put options, GE will continue to provide critical plant maintenance services throughout the remaining estimated useful life of the project.

The table below lists our investments accounted for under the equity method at December 31, 2008 and 2007 (in millions):

	Ownership Interest as of December 31, 2008	2008	2007
Greenfield LP	50%	$ 46	$ 114
OMEC	100%	98	146
Whitby	50%	—	—
Total investments		$ 144	$ 260

Greenfield LP — Greenfield LP is a limited partnership between certain subsidiaries of ours and of Mitsui & Co., Ltd., formed for the purpose of constructing and operating the Greenfield Energy Centre, a 1,005 MW natural gas-fired power plant in Ontario, Canada. We and Mitsui & Co., Ltd. each hold a 50% interest in Greenfield LP. On May 31, 2007, Greenfield LP entered into a Can$648 million non-recourse project finance facility, which was structured as a construction loan and converted to an 18-year term loan soon after the power plant began commercial operations, which occurred on October 17, 2008. Borrowings under the project finance facility are initially priced at Canadian LIBOR plus 1.2% or Canadian prime rate plus 0.2%. We contributed $8 million and $68 million during the years ended December 31, 2008 and 2007, respectively, as an additional investment in Greenfield LP. Our change in our investment in Greenfield LP is primarily due to distributions received, our share of Greenfield LP's net loss and changes in fair value on an interest rate swap which is reflected in OCI.

OMEC — OMEC, an indirect wholly owned subsidiary, is the owner of the Otay Mesa Energy Center, a 596 MW natural gas-fired power plant currently under construction in southern San Diego County, California. We deconsolidated OMEC during the second quarter of 2007 as a result of a 10-year tolling agreement we entered into with SDG&E and assignment of rights under an existing ground lease and ground sublease and easement agreement to SDG&E in May 2007. The assignment of the ground lease and ground sublease, among other things, provides for a put option by OMEC to sell, and a call option by SDG&E to buy, the Otay Mesa Energy Center at the end of the tolling agreement. The new tolling agreement and assignment of the ground lease and ground sublease required us to reconsider if OMEC constituted a VIE and if we should continue to consolidate OMEC. We considered that OMEC was designed to create and pass along construction, operational and credit risk to us and the lenders. We determined the most significant risk was determined to be price risk, which was designed to create and pass along to SDG&E. We have some exposure to price risk, to the extent the plant value in year 10 is between $280 million and $377 million. However, we determined SDG&E has the greatest price variability compared to us. Accordingly, we determined deconsolidation in the second quarter of 2007 was appropriate.

On May 3, 2007, OMEC entered into a $377 million non-recourse project finance facility to finance the construction of Otay Mesa Energy Center. The project finance facility is structured as a construction loan, converting to a term loan upon commercial operation of Otay Mesa Energy Center, and matures in April 2019. Borrowings under the project finance facility are initially priced at LIBOR plus 1.5%. We contributed $9 million and $156 million during the years ended December 31, 2008 and 2007, respectively, as an additional investment in OMEC. We received nil in distributions for both the years ended December 31, 2008 and 2007, respectively.

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

Our loss from unconsolidated investments in power plants is included in other operating expense on our Consolidated Statements of Operations. The following details our income (loss) and distributions from investments in unconsolidated power projects for the years ended December 31, 2008, 2007 and 2006 (in millions):

	Income (Loss) from Unconsolidated Investments in Power Plants			Distributions		
	2008	2007	2006	2008	2007	2006
OMEC	$ (55)	$ (9)	$ —	$ —	$ —	$ —
Greenfield LP	(5)	(12)	—	24	104	—
RockGen	9	—	—	—	—	—
Whitby	2	—	—	3	—	—
Impairment of equity method investment (Auburndale)	(180)	—	—	—	—	—
Total	$ (229)	$ (21)	$ —	$ 27	$ 104	$ —

Significant Subsidiary — OMEC meets the definition of a significant subsidiary based upon the relationship of our net loss from our investment to our consolidated net income. Condensed financial statements for our unconsolidated subsidiaries are set forth below (in millions):

Condensed Combined Balance Sheets of Our Unconsolidated Subsidiaries December 31, 2008 and 2007

	2008	2007
Assets:		
Cash and cash equivalents	$ 39	$ 36
Current assets	91	53
Property, plant and equipment, net	1,006	833
Other assets	95	107
Total assets	$ 1,231	$ 1,029
Liabilities:		
Current maturities of long-term debt	$ 24	$ 4
Current liabilities	97	102
Long-term debt	673	443
Long-term derivative liabilities	154	28
Other liabilities	48	47
Total liabilities	996	624
Member's interest	235	405
Total liabilities and member's interest	$ 1,231	$ 1,029

Condensed Combined Statements of Operations of Our Unconsolidated Subsidiaries For the Year Ended December 31, 2008, 2007 and 2006

	2008	2007(1)	2006(1)
Revenues	$ 121	$ 42	$ 38
Operating expenses	106	35	28
Impairment of equity method investment	180	—	—
Income from operations	(165)	7	10
Interest (income) expense	12	(1)	—
Other (income) expense, net	58	17	1
Net (loss) income	$ (235)	$ (9)	$ 9

(1) Amounts include results from Auburndale and RockGen during the periods they were deconsolidated in 2008. See further discussion below related to Deconsolidation VIE Transactions. Amounts prior to OMEC's deconsolidation in the second quarter of 2007 are included in our Consolidated Statements of Operations.

Our risk of loss related to our unconsolidated VIEs is limited to our investment balance. The debt on the books of our unconsolidated investments is not reflected on our Consolidated Balance Sheets. As of December 31, 2008 and 2007, equity method investee debt was approximately $697 million and $436 million, respectively. Based on our pro rata share of each of the investments, our share of such debt would be approximately $477 million and $253 million as of December 31, 2008 and 2007, respectively. All such debt is non-recourse to us.

Related-Party Transactions with Unconsolidated VIEs

We enter into various agreements with respect to power projects including projects managed by unconsolidated subsidiaries. Specifically, CES has executed an energy services agreement with Greenfield LP whereby CES will provide fuel and energy management services to the joint venture.

Deconsolidation VIE Transactions

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

Our purchase of the RockGen Energy Center assets during the first quarter of 2008 terminated the sale-leaseback agreement, which required us to reconsider if we were RockGen's primary beneficiary. RockGen's PPA with WP&L contained a call option which allowed WP&L and related parties to purchase the RockGen Energy Center assets at a fixed price on May 31, 2009, provided they gave us 180 days prior written notice. The call option effectively created a ceiling value for us and absorbed the majority of the expected change in fair value of the RockGen Energy Center assets and transferred it to WP&L. As a result, we determined that we were not RockGen's primary beneficiary. Accordingly, we deconsolidated RockGen during the first quarter of 2008, and accounted for our investment in RockGen under the equity method through December 2, 2008.

On December 2, 2008, (180 days prior to May 31, 2009) WP&L's period to exercise the purchase option expired without WP&L providing written notification. This resulted in a reconsideration event as to who is RockGen's primary beneficiary. We determined that expiration of the option eliminated the transfer of the risk of loss and potential for future reward to us and that we are RockGen's primary beneficiary. We reconsolidated RockGen as of December 2, 2008. The expiration of the purchase option also terminated WP&L's variable interest and RockGen is no longer a VIE. The reconsolidation resulted in the addition to our Consolidated Balance Sheet of $141 million in property, plant and equipment, $11 million in other assets and $2 million in liabilities and removal of $150 million representing our investment balance in RockGen.

Auburndale — Pomifer, an unrelated party, held a preferred interest in our Auburndale subsidiary, which entitled Pomifer to approximately 70% of Auburndale's cash distributions through 2013. Pomifer held a cash purchase option which, upon exercise, entitled Pomifer to an additional cash distribution of 20% through 2013 and also held certain "drag-along" rights, which, if exercised by Pomifer in connection with a sale of Auburndale, would require us also to sell our equity interest in Auburndale. On August 21, 2008, Pomifer exercised its purchase option. Our Auburndale subsidiary was a VIE and Pomifer's exercise of the option resulted in a consolidation reconsideration event under GAAP. We determined that Pomifer now absorbed the majority of expected losses and residual returns from the entity such that we were no longer Auburndale's primary beneficiary. Accordingly, we deconsolidated Auburndale during the third quarter of 2008.

The deconsolidation of Auburndale resulted in a reduction of approximately $131 million of property, plant and equipment, $142 million of other assets, $73 million of preferred interest debt and $21 million of other net liabilities to our Consolidated Balance Sheet as of August 21, 2008. On September 30, 2008, Pomifer notified us of their intent to exercise the drag-along provision. Accordingly, we determined that a sale of our remaining interest was probable. We compared our expected proceeds from such sale to the net book value of our interest in Auburndale at September 30, 2008, to determine if an impairment existed and, as a result, recorded an impairment loss of approximately $180 million, which is included in loss from unconsolidated investments in power plants on our 2008 Consolidated Statement of Operations. We subsequently sold our remaining interest in Auburndale on November 21, 2008. Accordingly, Auburndale is no longer a VIE.

6. Other Assets

As of December 31, 2008 and 2007, the components of other assets were (in millions):

	2008	2007
Prepaid lease, net of current portion	$ 115	$ 117
Notes receivable, net of current portion	83	129
Deferred financing costs, net of current portion	211	78
Deposits	26	256
SFAS No. 133 transition asset	—	136
Other	181	302
Other assets	$ 616	$ 1,018

Prepaid Lease, Net of Current Portion — Included in prepaid lease, net of current portion, are operating leases for South Point Energy Center and Gilroy Energy Center at December 31, 2008 and 2007.

Notes Receivable, Net of Current Portion — As of December 31, 2008 and 2007, there was $98 million and $119 million, respectively, included in notes receivable, net of current portion, of secured financing for notes that we sold to a group of institutional investors. These notes receivable resulted from the restructuring of a PPA between Gilroy and PG&E and were scheduled to be paid by PG&E during the period from February 2003 to September 2014. In December 2003, we sold our right to receive payments from PG&E under the notes for $133 million in cash. We recorded the transaction as a secured financing, with a note payable of $133 million. The notes receivable balance and note payable balance are both reduced as PG&E makes payments to the buyers of the notes receivable. The $24 million difference between the $157 million book value of the notes receivable at the transaction date and the $133 million cash received is recognized as additional interest expense over the repayment term. We will continue to record interest income over the repayment term and interest expense on the amortizing note payable balance. The fair value of the note receivable as of December 31, 2008, was $96 million.

Deferred Financing Costs, Net of Current Portion — Deferred financing costs relate to certain of our debt instruments which are considered not subject to compromise. See Note 8 for further discussion of these debt instruments.

Deposits — Deposits include margin deposits as well as other deposits. The balance at December 31, 2007, also includes the purchase value of the RockGen Energy Center.

SFAS No. 133 Transition Asset — SFAS No. 133 transition asset consists of the remaining unamortized value of our after-tax gain of $182 million recorded in 2003 as a cumulative effect of a change in accounting principle from the adoption of certain provisions of SFAS No. 133 related to normal purchases and normal sales. All of the remaining balance was removed from our Consolidated Balance Sheet when Auburndale was deconsolidated during 2008 as described in Note 5.

Other — Other consists of lease levelization costs, retained natural gas assets and deferred transmission credits.

7. Asset Sales and Purchase

2008

On January 15, 2008, we purchased the RockGen Energy Center from the RockGen Owner Lessors. RockGen previously leased the RockGen Energy Center from the RockGen Owner Lessors (which are not affiliates of ours) pursuant to a leveraged operating lease. We purchased the RockGen Energy Center for an allowed general unsecured claim of approximately $145 million, plus interest. As a result of the lease termination and related acquisition, we recorded $102 million in reorganization items on our 2007 Consolidated Statement of Operations to expense prepaid lease assets related to the RockGen Energy Center.

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

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

On August 21, 2008, Pomifer exercised its purchase option to purchase additional cash distributions of 20% through 2013 from Auburndale as further described in Note 5. On September 30, 2008, we received notice that Pomifer had entered into an asset purchase agreement with a third party and that Pomifer intended to exercise its drag-along rights to sell 100% of Auburndale. We recorded an impairment charge of approximately $180 million based upon the anticipated sales proceeds. We sold our remaining interest in Auburndale on November 21, 2008.

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

2007

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 included in reorganization items on our Consolidated Statements of Operations. 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 included in reorganization items on our Consolidated Statements of Operations.

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. We recorded a pre-tax gain of $135 million included in reorganization items on our Consolidated Statements of Operations.

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 included in reorganization items on our Consolidated Statements of Operations.

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, after having recorded a pre-tax, predominately non-cash impairment charge of approximately $89 million, to record our interest in Acadia PP at fair value less cost to sell, both of which charges are included in reorganization items on our Consolidated 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 Statements of Operations.

The sales of the Aries Power Plant, the Goldendale Energy Center, the Parlin Power Plant and our interest in Acadia PP did not meet the criteria for discontinued operations due to our continuing activity in the markets in which these power plants operate or were located; therefore, the results of operations for all periods prior to sale are included in our continuing operations. 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.

2006

On September 28, 2006, our indirect wholly owned subsidiary, Calpine European Finance LLC, completed the sale of its entire equity interest in its wholly owned subsidiary TTS to Ansaldo Energia S.p.A for €19 million or US$24 million (at then-current exchange rates). The proceeds of the sale were deposited in an escrow account and divided among us, PSM, and CCRC (a Canadian Debtor) in 2007, based primarily on accounts receivable from TTS and certain other intercompany obligations. Both Calpine European Finance LLC and TTS had been deconsolidated for accounting purposes as a result of the CCAA filings, and our investment in TTS had been accounted for under the cost method since the Petition Date, but for all periods prior to the Petition Date, the results of operations were included in our continuing operations.

On October 1, 2006, we completed the sale of the Dighton Power Plant, a 170 MW natural gas-fired power plant located in Dighton, Massachusetts to BG North America, LLC for $90 million after completing an auction process in the U.S. Bankruptcy Court. We recorded a pre-tax gain of approximately $87 million included in reorganization items on our Consolidated Statements of Operations. This asset sale did not meet the criteria for discontinued operations due to our continuing involvement in the market in which the Dighton Power Plant operates and therefore, the results of operations for all periods prior to sale are included in our continuing operations.

On October 2, 2006, we completed the sale of a partial ownership interest in Russell City Energy Company, LLC, the owner of the Russell City Energy Center, a proposed 600 MW natural gas-fired power plant to be built in Hayward, California, to ASC after completing an auction process in the U.S. Bankruptcy Court. As part of the transaction, we received approval from the U.S. Bankruptcy Court to transfer the Russell City project assets, which the parties have agreed are valued at approximately $81 million, to a newly formed entity in which we have a 65% ownership interest and ASC has a 35% ownership interest. In exchange for its 35% ownership interest, ASC has agreed to provide approximately $44 million of capital funding and to post an approximately $37 million letter of credit as required under a PPA with PG&E related to the Russell City project. We have the right to reacquire ASC's 35% interest during the period beginning on the second anniversary and ending on the fifth anniversary of commercial operations of the power plant. Exercise of the buyout right requires 180 days prior written notice to ASC and payment of an amount necessary to yield a stipulated pre-tax internal rate of return to ASC, calculated using assumptions specified in the transaction agreements. Construction is anticipated to begin once all permits and other required approvals are final and non-appealable, and project financing has closed.

On October 11, 2006, we completed the sale of our leasehold interest in the Fox Energy Center, a 560 MW natural gas-fired power plant located in Kaukauna, Wisconsin, for $16 million in cash and the extinguishment of financing obligations of $352 million, plus accrued interest. We recorded a pre-tax gain of approximately $2 million included in reorganization items on our Consolidated Statements of Operations. This asset sale did not meet the criteria for discontinued operations due to our continuing involvement in the market in which the Fox Energy Center operates and therefore, the results of operations for all periods prior to sale are included in our continuing operations.

Assets Held for Sale

There were no assets held for sale at December 31, 2008. At December 31, 2007, our current assets held for sale consisted of construction in progress of the Fremont and Hillabee development projects totaling $195 million.

Discontinued Operations

On December 1, 2008, the U.S. Bankruptcy Court finalized the settlement with Rosetta of all of our outstanding claims related to our domestic oil and gas assets we sold to Rosetta for $1.1 billion in 2005. Under the settlement, Rosetta paid us $97 million, we completed the transfer of certain other assets, we and Rosetta extended an existing natural gas purchase agreement for an additional 10 years and executed mutual releases.

Our original sale of our oil and gas assets was recorded as discontinued operations on our 2005 Consolidated Statement of Operations. Of the $97 million settlement proceeds received, $79 million was associated with the certain other assets with a remaining net book value of approximately $42 million related to our domestic oil and gas assets we sold to Rosetta in 2005. The resulting $37 million gain is reflected as discontinuing operation in our 2008 Consolidated Statement of Operations. The remaining $18 million settlement proceeds received was associated with the agreed upon fraudulent conveyance of $12 million, which is included in reorganization items on our 2008 Consolidated Statement of Operations, and approximately $6 million in revenues collected by Rosetta during the litigation period on properties retained by us. None of our asset sales in 2007 and 2006 met the criteria for treatment as discontinued operations.

The table below presents our components of our discontinued operations for the year ended December 31, 2008 (in millions):

	2008
Income from discontinued operations before taxes	$ 37
Less: income tax provision	14
Discontinued operations, net of tax	$ 23

8. Debt

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

	2008	2007
Exit Credit Facility	$ 6,645	$ —
DIP Facility	—	3,970
Second Priority Debt	—	3,672
Commodity Collateral Revolver	100	—
Construction/project financing	1,525	1,442
CCFC financing	778	780
Preferred interests	335	575
Notes payable and other borrowings	356	432
Capital lease obligations	733	785
Total debt(1)	10,472	11,656
Less: Current maturities	716	1,710
Debt, net of current portion	$ 9,756	$ 9,946

(1) Our debt balances at December 31, 2007, do not include $3.7 billion in debt that was classified as LSTC. These balances were settled upon our emergence from Chapter 11 on the Effective Date. See Note 3 for a further discussion of our emergence from Chapter 11.

Annual Debt Maturities

Contractual annual principal repayments or maturities of debt instruments, as of December 31, 2008, are as follows (in millions):

2009	$ 716
2010	434
2011	1,822
2012	138
2013	144
Thereafter	7,239
Total debt	10,493
(Discount)	(21)
Total	$ 10,472

The major components of our current maturities as of December 31, 2008, are as follows (in millions):

Exit Credit Facility	$ 119
CCFC financing	366
Other various current maturities	231
Total current maturities	$ 716

Exit Credit Facility

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

- The Exit Credit Facility, comprising (i) approximately $6.0 billion of senior secured term loans; (ii) a $1.0 billion senior secured revolving facility; and (iii) the ability to raise up to $2.0 billion of incremental term loans available on a senior secured basis in order to refinance secured debt of subsidiaries under an "accordion" provision; and

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

On the Effective Date, we fully drew on our approximately $6.0 billion of senior secured term loans and the $300 million Bridge Facility and we drew approximately $150 million under the $1.0 billion senior secured revolving facility. The proceeds of the drawdowns, above the amounts that had been applied under the DIP Facility as described below, were used to repay a portion of the Second Priority Debt, fund distributions under the Plan of Reorganization to holders of other secured claims and to pay fees, costs, commissions and expenses in connection with the Exit Facilities and the implementation of our Plan of Reorganization. Term loan borrowings under the Exit Credit Facility bear interest at a floating rate of, at our option, LIBOR plus 2.875% per annum or base rate plus 1.875% per annum. Borrowings under the Exit Credit Facility term loan facility require quarterly payments of principal equal to 0.25% of the original principal amount of the term loan, with the remaining unpaid amount due and payable at maturity on March 29, 2014.

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

On October 2, 2008, we borrowed $725 million under our Exit Credit Facility revolving facility. The borrowing was made as a base rate loan which initially bore interest at the base rate (5% on date of borrowing) plus 1.875% per annum. Proceeds from the borrowing were invested in money market funds, which are mainly invested in U.S. Treasury securities or other obligations issued or guaranteed by the U.S. government, its agencies or instrumentalities.

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

- Incur additional indebtedness and issue stock;
- Make prepayments on or purchase indebtedness in whole or in part;
- Pay dividends and other distributions with respect to our stock or repurchase our stock or make other restricted payments;
- Use money borrowed under the Exit Credit Facility for non-guarantors (including foreign subsidiaries);
- Make certain investments;
- Create or incur liens to secure debt;
- Consolidate or merge with another entity, or allow one of our subsidiaries to do so;
- Lease, transfer or sell assets and use proceeds of permitted asset leases, transfers or sales;
- Limit dividends or other distributions from certain subsidiaries up to Calpine Corporation;
- Make capital expenditures beyond specified limits;
- Engage in certain business activities; and
- Acquire facilities or other businesses.

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

As of December 31, 2008, under the Exit Credit Facility we had approximately $5.9 billion outstanding under the term loan facilities, $725 million borrowings outstanding under the revolving credit facility and $259 million of letters of credit issued against the revolving credit facility.

DIP Facility

As of December 31, 2007, our primary debt facility was the DIP Facility. The DIP Facility consisted of a $4.0 billion first priority senior secured term loan and a $1.0 billion first priority senior secured revolving credit facility together with an uncommitted term loan facility that permitted us to raise up to $2.0 billion of incremental term loan funding on a senior secured basis with the same priority as the then current debt under the DIP Facility. In addition, under the DIP Facility, the U.S. Debtors had the ability to provide liens to counterparties to secure obligations arising under certain hedging agreements. The DIP Facility bore interest at LIBOR plus 2.25% or base rate plus 1.25% and matured upon the Effective Date, when the loans and commitments under the DIP Facility were converted to loans and commitments under our Exit Facilities. Due to the conversion of the loans under the DIP Facility to loans under our Exit Facilities and our emergence from Chapter 11 prior to the issuance of our Consolidated Financial Statements for the year ended December 31, 2007, the borrowings under the DIP Facility were classified as non-current at December 31, 2007. Amounts drawn under the DIP Facility had been applied on March 29, 2007, to the repayment of a portion of the approximately $2.5 billion outstanding principal amount of CalGen Secured Debt, and to the refinancing of our Original DIP Facility. Borrowings under the Original DIP Facility had been used to repay a portion of the First Priority Notes and to pay a portion of the purchase price for the Geysers Assets, as well as to fund our operational needs.

Second Priority Debt

The components of our Second Priority Debt are (in millions, except for interest rates):

	Outstanding at December 31,		Effective Interest Rates	
	2008[1]	2007	2008[1]	2007
Second Priority Senior Secured Term Loans Due 2007	$ —	$ 1,150	—%	13.3%
Second Priority Senior Secured Floating Rate Notes Due 2007	—	900	—	11.1
Second Priority Senior Secured Notes Due 2010	—	733	—	8.5
Second Priority Senior Secured Notes Due 2011	—	489	—	9.9
Second Priority Senior Secured Notes Due 2013	—	400	—	8.7
Total Second Priority Debt	$ —	$ 3,672		

(1) On the Effective Date, the Second Priority Debt was repaid with excess cash on hand and amounts drawn under our Exit Facilities in accordance with our Plan of Reorganization.

Construction/Project Financing

The components of our construction/project financing are (in millions, except for interest rates):

	Outstanding at December 31,		Effective Interest Rates	
	2008	2007	2008	2007
Bethpage Energy Center 3, LLC due 2020-2025[1]	$ 112	$ 115	6.9%	7.0%
Gilroy Energy Center, LLC due 2011	113	150	7.3	7.1
Blue Spruce due 2017	83	56	5.8	12.8
Riverside Energy Center, LLC due 2011	328	344	9.3	11.2
Rocky Mountain Energy Center, LLC due 2011	164	211	9.9	11.1
Metcalf due 2015	264	100	7.9	8.8
Steamboat Holdings, LLC due 2011[2]	453	459	6.5	8.0
Other	8	7	—	—
Total	$ 1,525	$ 1,442		

(1) Represents a weighted average of first and second lien loans.

(2) Previously reported separately as Mankato Energy Center, LLC and Freeport Energy Center, LP.

Our construction/project financings are collateralized solely by the capital stock or partnership interests, physical assets, contracts and/or cash flows attributable to the entities that own the power plants. The lenders recourse under these project financings is limited to such collateral. See Note 16 for a discussion of project financings guaranteed by us.

On January 21, 2009, Deer Park, our indirect wholly owned subsidiary, closed on $156 million of senior secured credit facilities, which include a $150 million term facility and a $6 million letter of credit facility. Proceeds received were used to repay an existing obligation of approximately $79 million, pay financing and legal fees of approximately $7 million, fund approximately $15 million in restricted cash and the remainder was distributed to Calpine Corporation for general corporate purposes. The senior term loan facility matures on January 21, 2012, and bears interest at Deer Park's option of LIBOR plus 3.5% or base rate plus 2.5%.

On February 1, 2008, Blue Spruce, an indirect wholly owned subsidiary, entered into a $90 million senior term loan. Net proceeds from the senior term loan were used to refinance all outstanding indebtedness under the existing Blue Spruce term loan facility, to pay fees and expenses related to the transaction and for general corporate purposes. The senior term loan carries interest at a base rate plus 0.63% which escalates to 1.50% or LIBOR plus 1.63%, which escalates to 2.50% over the life of the senior term loan and matures December 31, 2017. The senior term loan is secured by the assets of Blue Spruce. In connection with this refinancing, we recorded $7 million in loss on debt extinguishment, related to the write-off of deferred financing costs of $4 million and prepayment penalties of $3 million, which are recorded in other (income) expense, net on our 2008 Consolidated Statement of Operations.

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

At December 31, 2008 and 2007, $98 million and $108 million of letters of credit were issued against these project financing facilities, respectively. During the first quarter of 2008, we entered into a letter of credit facility related to our subsidiary Calpine Development Holdings, Inc. under which up to $150 million is available for letters of credit. As of December 31, 2008, $148 million in letters of credit had been issued and were outstanding under this facility.

CCFC Financing

The components of the CCFC financing are (in millions, except for interest rates):

	Outstanding at December 31,		Effective Interest Rates	
	2008	2007	2008	2007
Second Priority Senior Secured Floating Rate Notes Due 2011	$ 412	$ 411	12.6%	14.3%
First Priority Senior Secured Institutional Term Loans Due 2009	366	369	10.3	12.1
Total CCFC financing	$ 778	$ 780		

The CCFC secured notes and term loans are collateralized through a combination of pledges of the equity interests in and/or assets (other than excluded assets) of CCFC and its subsidiaries, other than CCFC Finance Corp. The CCFC secured noteholders' and term loan lenders' recourse is limited to such collateral and none of the CCFC indebtedness is guaranteed by us.

Preferred Interests

Our preferred interests meet the criteria of mandatorily redeemable financial instruments and are therefore classified as debt. The components of preferred interests are (in millions, except for interest rates):

	Outstanding at December 31,		Effective Interest Rates	
	2008	2007	2008	2007
Preferred interest in Auburndale Power Plant due 2013(1)	$ —	$ 76	—%	17.1%
Preferred interest in GEC Holdings, LLC due 2011	35	44	14.8	12.9
Preferred interest in Metcalf due 2010	—	155	—	15.2
Preferred interest in CCFCP due 2011	300	300	13.5	15.4
Total preferred interests	$ 335	$ 575		

(1) Amounts were repaid in connection with the sale of our interest in Auburndale.

Notes Payable and Other Borrowings

The components of notes payable and other borrowings are (in millions, except for interest rates):

	Outstanding at December 31,		Effective Interest Rates	
	2008	2007	2008	2007
PCF III due 2010	$ 76	$ 68	10.2%	12.0%
PCF due 2010	159	256	9.6	11.4
Gilroy note payable due 2014	89	100	10.7	—
Whitby Holdings due 2017	26	—	9.5	—
Other	6	8	6.0	—
Total notes payable and other borrowings	$ 356	$ 432		

Capital Lease Obligations

The following is a schedule by year of future minimum lease payments under capital leases together with the present value of the net minimum lease payments as of December 31, 2008 (in millions):

	Total
Years Ending December 31:	
2009	$ 108
2010	97
2011	97
2012	96
2013	93
Thereafter	861
Total minimum lease payments	1,352
Less: Amount representing interest	619
Present value of net minimum lease payments	$ 733

The primary types of property leased by us are power plants and related equipment. The leases generally provide for the lessee to pay taxes, maintenance, insurance, and certain other operating costs of the leased property. The remaining lease terms range up to 40 years. Some of the lease agreements contain customary restrictions on dividends, additional debt and further encumbrances similar to those typically found in project financing agreements. As of December 31, 2008 and 2007, the asset balances for the leased assets totaled $1,292 million and $1,145 million, respectively, with accumulated amortization of $279 million and $253 million, respectively. Of these balances, as of December 31, 2008 and 2007, $115 million of leased assets and $21 million and $17 million, respectively, of accumulated amortization were related to the King City power plant. The King City power plant is owned by an affiliate of CPIF, in which we currently hold no interest. Our minimum lease payments are not tied to an existing variable index or rate.

Other Financing Agreements

On June 25, 2008, we entered into the Knock-in Facility, a 12-month, $200 million letter of credit facility. Our obligations under the Knock-in Facility are unsecured. Availability of letters of credit for issuance under the

Knock-in Facility is up to a total maximum availability of $200 million contingent on natural gas futures contract prices exceeding certain thresholds, with initial availability for up to $50 million. As of December 31, 2008, $50 million in letters of credit had been issued and were outstanding under this facility.

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

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

Letters of Credit Facilities

The table below represents amounts outstanding under our letter of credit facilities as of December 31, 2008 and 2007 (in millions):

	2008	2007
Exit Credit Facility	$ 259	$ —
DIP Facility	—	235
Calpine Development Holdings, Inc.	148	—
Knock-in Facility	50	—
Various project financing facilities	99	113
Total	$ 556	$ 348

Fair Value of Debt

As we did not elect to apply the provisions of SFAS No. 159, "The Fair Value Option for Financial Assets and Financial Liabilities – Including an Amendment of FASB Statement No. 115," we record our debt instruments based upon contractual terms, net of any applicable premium or discount. We measured the fair value of our debt instruments as of December 31, 2008 using market information including credit default swap rates and historical default information, quoted market prices and discounted cash flow analyses based on our current borrowing rates for similar types of borrowing arrangements. The following table details the fair values and carrying values of our debt instruments as of December 31, 2008 and 2007 (in millions):

	2008		2007	
	Fair Value	Carrying Value	Fair Value	Carrying Value
Exit Credit Facility	$ 4,812	$ 6,645	$ —	$ —
DIP Facility	—	—	3,970	3,970
Commodity Collateral Revolver	85	100	—	—
Construction/project financing	1,420	1,525	1,442	1,442
CCFC financing	727	778	780	780
Preferred interests	305	335	575	575
Notes payable and other borrowings	330	356	466	432
Second Priority Debt[1]	—	—	3,672	3,672
Total	$ 7,679	$ 9,739	$ 10,905	$ 10,871

(1) Carrying amount approximates fair value as the amounts were paid in full on the Effective Date.

9. Income Taxes

The jurisdictional components of net income (loss) from continuing operations before provision (benefit) for income taxes and discontinued operations for the years ended December 31, 2008, 2007 and 2006, are as follows (in millions):

	2008	2007	2006
U.S.	$ (30)	$ 2,160	$ (1,696)
International	(30)	(13)	(5)
Income (loss) before income taxes and discontinued operations	$ (60)	$ 2,147	$ (1,701)

The components of the provision (benefit) for income taxes on continuing operations for the years ended December 31, 2008, 2007 and 2006, consists of the following (in millions):

	2008	2007	2006
Current:			
Federal	$ (10)	$ (25)	$ —
State	2	11	25
Foreign	(66)	(15)	17
Total current	(74)	(29)	42
Deferred:			
Federal	24	(449)	(4)
State	3	(68)	26
Total deferred	27	(517)	22
Total provision (benefit)	$ (47)	$ (546)	$ 64

A reconciliation of the U.S. federal statutory rate of 35% to our effective rate from continuing operations is as follows for the years ended December 31, 2008, 2007 and 2006:

	2008	2007	2006
Expected tax (benefit) rate at U.S. statutory tax rate	(35.0)%	35.0%	(35.0)%
State income tax provision (benefit), net of federal benefit	9.7	(2.6)	2.9
Depletion in excess of basis	(12.1)	—	0.7
Valuation allowances against future tax benefits	323.6	5.7	26.2
Tax credits	(3.2)	—	(0.1)
Foreign tax at rates other than U.S. statutory rate	(78.7)	1.6	1.9
Non-deductible reorganization items	(118.3)	(65.2)	5.4
Income from cancellation of indebtedness	43.7	—	—
Intraperiod allocation pursuant to OCI	(124.2)	—	—
Bankruptcy settlement	(92.5)	—	—
Change in unrecognized tax benefits	5.8	(1.9)	—
Change in prior year estimate to actual provision	—	2.4	—
Permanent differences and other items	2.9	(0.4)	1.8
Effective income tax provision (benefit) rate	(78.3)%	(25.4)%	3.8%

The components of the deferred income taxes, net of current portion as of December 31, 2008 and 2007, are as follows (in millions):

	2008	2007
Deferred tax assets:		
NOL and credit carryforwards	$ 3,361	$ 2,230
Taxes related to risk management activities and derivatives	10	12
Reorganization items and impairments	583	1,410
Other differences	6	8
Deferred tax assets before valuation allowance	3,960	3,660
Valuation allowance	(2,685)	(2,401)
Total deferred tax assets	1,275	1,259
Deferred tax liabilities: property, plant and equipment	(1,352)	(1,241)
Net deferred tax (liability) asset	(77)	18
Less: Current portion deferred tax asset	1	39
Less: Non-current deferred tax asset	15	17
Deferred income taxes, net of current portion	$ (93)	$ (38)

For federal income tax reporting purposes our consolidated GAAP financial reporting group is comprised primarily of two groups, CCFC and its subsidiaries, which we refer to as the CCFC group and Calpine Corporation and its subsidiaries other than CCFC, which we refer to as the Calpine group. This is due to a preferred financing transaction in 2005 resulting in the deconsolidation of the CCFC group for income tax purposes. The CCFC group no longer has a valuation allowance recorded against its deferred tax assets due to its ability to generate sufficient income to utilize its NOLs. Furthermore, intraperiod tax allocation provisions of SFAS No. 109 require allocation of a tax benefit to continuing operations due to current OCI gains. We have recorded a tax benefit of $90 million included in our loss before discontinued operations on our 2008 Consolidated Statement of Operations with an offsetting $76 million tax provision in OCI and a $14 million tax provision in income from discontinued operations. The tax expense recorded in OCI is expected to reverse through continuing operations in future periods.

Our carryforwards consist primarily of federal NOL carryforwards of approximately $7.5 billion which expire between 2023 and 2028, and state NOL carryforwards of approximately $4.4 billion which expire between 2009 and 2028. The NOL carryforwards available are subject to limitations on their annual usage. This includes an NOL carryforward of approximately $396 million for our CCFC group. Under federal and applicable state income tax laws, 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 taxing authorities. In addition, we have approximately $1.0 billion in foreign NOLs with a full valuation allowance.

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

To prevent the risk of loss of our ability to utilize our tax NOL carryforwards, our amended and restated certificate of incorporation permits our Board of Directors to meet to determine whether to impose certain transfer restrictions on our common stock in the following circumstances: if, prior to February 1, 2013, our Market Capitalization declines by at least 35% from our Emergence Date Market Capitalization of approximately \$8.6 billion (calculated pursuant to our amended and restated certificate of incorporation) and at least 25 percentage points of shift in ownership has occurred with respect to our equity for purposes of Section 382 of the IRC. During 2008, and through the filing of this Report, we have experienced declines in our stock price of more than 50% from our Emergence Date Market Capitalization. As of the filing of this Report, our shift in ownership is approximately 10%.

We have filed a registration statement on Form S-3 registering the resale of the common stock held by two holders (or related groups of holders) of our common stock that collectively own approximately 47% of our common stock, which will permit them to sell a large portion of their shares of common stock without being subject to the "trickle out" or other restrictions of Rule 144 under the Securities Act. If these shareholders sought to sell all of their registered shares within a short period of time, pursuant to the Form S-3 or otherwise, it would result in a shift in ownership of greater than 25 percentage points and our Board of Directors could elect to impose certain trading restrictions on our common stock as described above.

These restrictions are not currently operative but could become operative in the future if the foregoing events occur and our Board of Directors elect to impose them. There can be no assurance that the circumstances will not be met in the future, or in the event that they are met, that our Board of Directors would choose to impose these restrictions or that, if imposed, such restrictions would prevent an ownership change from occurring.

GAAP requires that we consider all available evidence and tax planning strategies, both positive and negative, to determine whether, based on the weight of that evidence, a valuation allowance is needed. Future realization of the tax benefit of an existing deductible temporary difference or carryforward ultimately depends on the existence of sufficient taxable income of the appropriate character within the carryback or carryforward periods available under the tax law. Due to our history of losses, we were unable to assume future profits; however, at December 31, 2007, we were able to consider available tax planning strategies due to our expected emergence from Chapter 11. Future income from reversals of existing taxable temporary differences and tax planning strategies allowed a larger portion of the deferred tax assets to be offset against deferred tax liabilities resulting in a significant release of previously recorded valuation allowance.

As of December 31, 2008, we have provided a valuation allowance of \$2.7 billion on certain federal, state and foreign tax jurisdiction deferred tax assets to reduce the gross amount of these assets to the extent necessary to result in an amount that is more likely than not of being realized. For the years ended December 31, 2008, 2007 and 2006, the net change in the valuation allowance was an increase of \$284 million, \$80 million, and \$682 million, respectively, and primarily relates to our NOL carryforwards.

We adopted FIN 48 "Accounting for Uncertainty in Income Taxes" on January 1, 2007. As of that date, we had unrecognized tax benefits of \$240 million including an accrued liability of \$153 million, reduction of deferred tax assets of \$106 million and accrued interest and penalties of \$19 million. Uncertain tax positions relate primarily to the IRS positions taken in prior tax returns and certain withholding taxes. There was no effect on the January 1, 2007, accumulated deficit balance as a result of the adoption of FIN 48.

Our unrecognized tax benefits decreased by \$83 million and \$67 million for the years ended December 31, 2008 and 2007, respectively, primarily related to settlement of tax positions on withholding taxes and tax depreciation. If recognized, approximately $33 million of our unrecognized tax benefits would impact the annual effective tax rate and $57 million related to deferred tax assets would be offset against recorded valuation allowance. We also had accrued interest and penalties of $18 million for income tax matters as of December 31, 2008.

A reconciliation of the beginning and ending amount of our unrecognized tax benefits is as follows (in millions):

	2008	2007
Unrecognized tax benefits at beginning of year	$ (173)	$ (240)
Increases related to prior year tax positions	(2)	(28)
Decreases related to prior year tax positions	6	8
Increases related to current year tax positions	(7)	—
Settlements	84	87
Decrease related to lapse of statute of limitations	2	—
Unrecognized tax benefits at end of year	$ (90)	$ (173)

We believe it is reasonably possible that a decrease of up to $16 million in unrecognized tax benefits related primarily to state tax exposures could be recorded in 2009. The IRS completed its examination of our U.S. income tax returns for the 1997 through 2006 tax years. The U.S. Joint Committee on Taxation issued its approval of the examination on January 31, 2008. The examination did not result in a material impact on our Consolidated Financial Statements. 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 Financial Statements. Only our U.S. income tax return for 2007 remains subject to IRS examination. However, any NOLs incurred prior to 2008 and claimed in future return 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.

10. Fair Value Measurements

Effective January 1, 2008, we adopted SFAS No. 157, which provides a framework for measuring fair value under GAAP and, among other things, requires enhanced disclosures about assets and liabilities carried at fair value. As defined in SFAS No. 157, fair value is the price that would be received to sell an asset or paid to transfer a liability in the principal or most advantageous market in an orderly transaction between market participants at the measurement date (exit price). SFAS No. 157 is to be applied prospectively as of the beginning of the year of adoption, except for limited retrospective application to selected items including financial instruments that were measured at fair value using the transaction price in accordance with the requirements of EITF Issue No. 02-3, "Issues Involved in Accounting for Derivative Contracts Held for Trading Purposes and Contracts Involved in Energy Trading and Risk Management Activities." Day one gains and losses previously deferred under EITF Issue No. 02-3 should be recorded as a cumulative effect adjustment to opening retained earnings at the date of adoption. As of January 1, 2008, we recorded a non-cash reduction to retained earnings of approximately $22 million, $14 million net after tax benefit of $8 million, relating to the unamortized deferred loss on a derivative instrument. The determination of the fair value incorporates various factors required under SFAS No. 157. These factors include the credit standing of the counterparties involved and the impact of credit enhancements (such as cash deposits and first priority liens).

SFAS No. 157 establishes a fair value hierarchy that prioritizes the inputs used to measure fair value. The hierarchy gives the highest priority to unadjusted quoted prices in active markets for identical assets or liabilities (level 1 measurement) and the lowest priority to unobservable inputs (level 3 measurement). The three levels of the fair value hierarchy defined by SFAS No. 157 are as follows:

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

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

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

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

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

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

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

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

Our level 3 fair value derivative instruments primarily consist of our power and natural gas OTC forwards and options where pricing inputs are unobservable as well as other complex and structured transactions. Complex or structured transactions are tailored to our or our customers' needs and can introduce the need for internally-developed model inputs which might not be observable in or corroborated by the market. When such inputs have a significant impact on the measurement of fair value, the instrument is categorized in level 3. Our valuation models may incorporate historical correlation information and extrapolate available broker and other information to future periods. In cases where there is no corroborating market information available to support significant model inputs, we initially use the transaction price as the best estimate of fair value. OTC options are valued using industry-standard models, including the Black-Scholes pricing model. At each balance sheet date, we perform an analysis of all instruments subject to SFAS No. 157 and include in level 3 all of those whose fair value is based on significant unobservable inputs.

We assess non-performance risk by adjusting the fair value of our derivatives based on the credit standing of the counterparties involved and the impact of credit enhancements, if any. Such valuation adjustments represent the amount of probable loss due to default either by us or a third party. Our credit valuation methodology is based on a quantitative approach which allocates a credit adjustment to the fair value of derivative transactions based on the net exposure of each counterparty considering netting agreements, collateral and other credit support. We develop our credit reserve based on our expectation of the market participants' perspective of potential credit exposure. Our calculation of the credit reserve on net asset positions is based on available market information including credit ratings, historical default information and credit default swap rates. We also incorporate non-performance risk in net liability positions based on an assessment of market participant's assumptions of our potential risk of default. The net credit reserve as of December 31, 2008, was $79 million.

The following table sets forth by level within the fair value hierarchy our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2008. As required by SFAS No. 157, financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment, and may affect the valuation of fair value assets and liabilities and their placement within the fair value hierarchy levels.

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

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(1) Amounts represent cash equivalents invested in money market accounts and are included in cash and cash equivalents and restricted cash on our Consolidated Balance Sheet. As of December 31, 2008, we had cash equivalents of $1,597 million included in cash and cash equivalents and $495 million included in restricted cash.

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

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

The following table sets forth a reconciliation of changes in the fair value of our net derivative assets (liabilities) classified as level 3 in the fair value hierarchy for the year ended December 31, 2008 (in millions):

	2008
Balance, beginning of period[1]	$ (23)
Realized and unrealized gains (losses):	
Included in net income[2]	57
Included in OCI	229
Purchases, issuances and settlements, net	(97)
Transfers in and/or out of level 3[3]	(61)
Balance, end of period	$ 105
Change in unrealized gains relating to instruments still held as of December 31, 2008[2]	$ 57

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(1) Our portfolio of derivative assets and liabilities is adjusted for the day one loss of $(22) million, excluding the tax benefit of $8 million, recognized upon adoption of SFAS No. 157 on January 1, 2008.

(2) Includes $78 million recorded in operating revenues (for power contracts) and $(21) million recorded in fuel and purchased energy expense (for natural gas contracts) for the year ended December 31, 2008, respectively, as shown on our 2008 Consolidated Statement of Operations.

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

11. Derivative Instruments and Collateral

We utilize derivatives, which include physical commodity contracts and financial commodity instruments such as swaps and options, to attempt to maximize the risk-adjusted returns from our power and plant assets. We also utilize interest rate swaps to adjust the mix between fixed and floating rate debt as a hedge of our interest rate risk. By entering into these transactions, we are able to economically hedge a portion of our spark spread at pre-determined generation and price levels. Along with our portfolio of hedging transactions, we enter into power and natural gas positions that often act as hedges to our asset portfolio, but do not qualify as hedges under hedge accounting criteria guidelines, such as commodity options transactions and instruments that settle on power price to natural gas price relationships (Heat Rate swaps and options).

The table below reflects the amounts that are recorded as derivative assets and liabilities on our Consolidated Balance Sheets at December 31, 2008 and 2007, for our derivative instruments (in millions):

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

	2007		
	Interest Rate Swaps	Commodity Instruments	Total Derivative Instruments
Current derivative assets	$ —	$ 731	$ 731
Long-term derivative assets	—	290	290
Total derivative assets	$ —	$ 1,021	$ 1,021
Current derivative liabilities	$ 53	$ 753	$ 806
Long-term derivative liabilities	116	462	578
Total derivative liabilities	$ 169	$ 1,215	$ 1,384
Net derivative liabilities	$ (169)	$ (194)	$ (363)

As of December 31, 2008, the maximum length of our PPAs extend until 24 years into the future and the maximum length of time over which we were hedging using commodity and interest rate derivative instruments was 4 and 18 years, respectively. We currently estimate that pre-tax gains of $163 million would be reclassified from AOCI into earnings during the year ending December 31, 2009, as the hedged transactions affect earnings assuming constant natural gas and power prices and interest rates over time; however, the actual amounts that will be reclassified will likely vary based on changes in natural gas and power prices as well as interest rates. Therefore, management is unable to predict what the actual reclassification from AOCI to earnings (positive or negative) will be for the next twelve months.

Hedge ineffectiveness is included in mark-to-market activity. Gains (losses) due to ineffectiveness on commodity hedging instruments were $2 million, $(2) million and $(6) million for the years ended December 31, 2008, 2007 and 2006, respectively.

Collateral — We use margin deposits, prepayments and letters of credit as credit support with and from our counterparties for commodity procurement and risk management activities. In addition, we have granted additional liens on the assets currently subject to liens under the Exit Credit Facility to collateralize our obligations under certain of our power and natural gas agreements that qualify as "eligible commodity hedge agreements" under the Exit Credit Facility and certain of our interest rate swap agreements 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 liens ratably with the lenders under the Exit Credit Facility. Such first priority liens had also been permitted under the DIP Facility prior to the conversion of the loans and commitments under the DIP Facility to our exit financing under the Exit Credit Facility.

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

	2008	2007
Margin deposits	$ 653	$ 314
Natural gas and power prepayments	60	138
Total margin deposits and natural gas and power prepayments with our counterparties(1)	$ 713	$ 452
Letters of credit issued	$ 455	$ 231
First priority liens under power and natural gas agreements(2)	—	22
First priority liens under interest rate swap agreements	477	151
Total letters of credit and first priority liens with our counterparties	$ 932	$ 404
Margin deposits held by us posted by our counterparties	$ 169	$ 21
Letters of credit posted with us by our counterparties	95	18
Total margin deposits and letters of credit posted with us by our counterparties(3)	$ 264	$ 39

(1) $693 million and $364 million are included in margin deposits and other prepaid expense and $20 million and $88 million are included in other assets on our Consolidated Balance Sheets as of December 31, 2008 and 2007, respectively.

(2) At December 31, 2008, the fair value of our energy commodities granted under first priority liens is a gain of $201 million; therefore, there is no collateral exposure at December 31, 2008.

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

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

We did not elect to adopt the netting provisions allowed under FSP FIN 39-1, which allows an entity to offset the fair value amounts recognized for cash collateral paid or cash collateral received against the fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement. Of our total margin deposits posted with our counterparties, $622 million and $276 million were subject to master netting agreements as of December 31, 2008 and 2007, respectively. Total margin deposits posted as collateral by our counterparties with us of $169 million and $21 million were subject to master netting agreements as of December 31, 2008 and 2007, respectively.

12. Earnings (Loss) per Share

Pursuant to the Plan of Reorganization, all shares of our common stock outstanding prior to the Effective Date were canceled and the issuance of 485 million new shares of reorganized Calpine Corporation common stock was authorized to resolve allowed unsecured claims. In addition, approximately 2 million restricted shares of reorganized Calpine Corporation common stock were issued pursuant to the Calpine Equity Incentive Plans, net of forfeitures. A portion of the 485 million authorized shares was immediately distributed, and the remainder was reserved for distribution to holders of certain disputed claims that, although unresolved as of the Effective Date, later become allowed. To the extent that any of the reserved shares remain undistributed upon resolution of the disputed claims, such shares will not be returned to us but rather will be distributed pro rata to claimants with allowed claims to increase their recovery. Therefore, pursuant to the Plan of Reorganization, all 485 million shares ultimately will be distributed. Accordingly, although the reserved shares are not yet issued and outstanding, all conditions of distribution had been met for these reserved shares as of the Effective Date, and such shares are considered issued and are included in our calculation of weighted average shares outstanding.

Reconciliations of the amounts used in the basic and diluted earnings (loss) per common share computations for the years ended December 31, 2008, 2007 and 2006, are:

	2008	2007	2006
	(shares in thousands)		
Diluted weighted average shares calculation:			
Weighted average shares outstanding (basic)	485,054	479,235	479,136
Restricted stock awards	491	—	—
Employee stock options	1	243	—[1]
Weighted average shares outstanding (diluted)	485,546	479,478	479,136

(1) As we incurred a net loss during the year ended December 31, 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 for the years ended December 31, 2008, 2007 and 2006:

	2008	2007	2006
	(shares in thousands)		
Employee stock options[1]	7,248	16,825	28,094
Common stock warrants[1]	29,158	—	—
Restricted stock awards[1][2]	11	490	764
Convertible Senior Notes[3]	—	399,914	399,914
DB London loaned shares[4]	—	17,401	81,208

(1) Excluded from diluted weighted average shares as these equity-based instruments are anti-dilutive in accordance with the calculation under the treasury stock method prescribed by SFAS No. 128, "Earnings per Share."

(2) Excluded from diluted weighted average shares outstanding for the years ended December 31, 2007 and 2006, because our closing stock price had not reached the price at which the shares vest.

(3) Excluded from diluted weighted average shares outstanding because we believe the conversion rights were terminated upon our Chapter 11 filings.

(4) Excluded from basic and diluted weighted average shares outstanding as the share lending agreement with DB London required physical settlement of these common shares. See Note 15 for a discussion of this share lending agreement.

Although EPS information for the years ended December 31, 2007 and 2006, is presented, it is not comparable to the information presented for the year ended December 31, 2008, due to the changes in our capital structure on the Effective Date, which also included termination of all outstanding convertible securities.

13. Stock-Based Compensation

Calpine Equity Incentive Plans

The Calpine Equity Incentive Plans were approved as part of our Plan of Reorganization. These plans are administered by the Compensation Committee of our Board of Directors and provide for the issuance of equity awards to all employees as well as the non-employee members of our Board of Directors. The equity awards may include incentive or non-qualified stock options, restricted stock, restricted stock units, stock appreciation rights, performance compensation awards, and other stock-based awards. Under the MEIP and DEIP there are 14,833,000 shares and 167,000 shares, respectively, of reorganized Calpine Corporation common stock available for issuance to participants. We granted a total of 2,746,671 shares of restricted common stock and 9,204,620 employee stock options under the MEIP and the DEIP during the year ended December 31, 2008.

The equity awards granted under the Calpine Equity Incentive Plans vest over periods between one and five years, contain contractual terms of seven and ten years and are subject to forfeiture provisions under certain circumstances including termination of employment prior to vesting. In addition, employment inducement options to purchase a total of 4,636,734 shares were granted outside of the Calpine Equity Incentive Plans in connection with our hiring of a new Chief Executive Officer and a new Chief Legal Officer in August 2008, and a new Chief Commercial Officer in September 2008. Each of the employment inducement options vests over a period of five years, contains a contractual term of seven years and is subject to forfeiture under certain circumstances including termination of employment prior to vesting. Common stock for future stock option exercises will be issued from the MEIP share reserves or shares reserved for the employment inducement options issued outside of the MEIP.

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

Stock-based compensation expense (income) recognized was \$50 million, \$(1) million and \$5 million for the years ended December 31, 2008, 2007 and 2006, respectively. We did not record any tax benefits related to stock-based compensation expense in any period as we are not benefiting a significant portion of our deferred tax assets including deductions related to stock-based compensation expense. In addition, we did not capitalize any stock-based compensation expense as part of the cost of an asset for the years ended December 31, 2008, 2007 and 2006. At December 31, 2008, there was \$66 million of unrecognized compensation cost related to equity awards, which is expected to be recognized over a weighted-average period of 2.0 years for options, 1.0 years for restricted stock and 0.2 years for restricted stock units. We issue new shares from our reserves when stock options are exercised and for other stock-based awards.

A summary of all of our non-qualified stock option activity for the MEIP and DEIP and option issuances for employment inducements to hire new executives for the year ended December 31, 2008, is as follows:

	Number of Options	Weighted Average Exercise Price	Weighted Average Remaining Term (in years)	Aggregate Intrinsic Value (in millions)
Outstanding — December 31, 2007	—	\$ —		
Granted	13,841,354	\$ 19.55		
Exercised	—	\$ —		
Forfeited	1,000,600	\$ 17.37		
Expired	—	\$ —		
Outstanding — December 31, 2008	12,840,754	\$ 19.72	7.5	\$ —
Exercisable — December 31, 2008	400,700	\$ 17.43	7.5	\$ —
Vested and expected to vest — December 31, 2008	12,684,752	\$ 19.75	7.4	\$ —

The total intrinsic value of our employee stock options exercised was nil for which we received approximately \$1 million in cash proceeds during the year ended December 31, 2007, and there were no employee stock options exercised during the years ended December 31, 2008 and 2006.

The fair value of options (including employment inducement options) granted during the year ended December 31, 2008, was determined on the grant date using the Black-Scholes pricing model. Certain assumptions were used in order to estimate fair value for options as noted in the following table. No options were granted during the years ended December 31, 2007 and 2006.

	2008
Expected term (in years)[1]	5.0 – 6.1
Risk-free interest rate[2]	1.0 – 3.3%
Expected volatility[3]	34.8 – 98%
Dividend yield[4]	—
Weighted average grant-date fair value (per option)	\$ 6.48

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

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

(3) Volatility calculated using our weighted average implied volatility and our industry peers' exchange traded stock options.

(4) We do not expect to issue dividends at any time in the near or long term.

No restricted stock or restricted stock units have been granted other than under our MEIP and DEIP. A summary of our restricted stock and restricted stock unit activity for the MEIP and DEIP for the year ended December 31, 2008, is as follows:

	Number of Restricted Stock Awards	Weighted Average Grant-Date Fair Value
Nonvested — December 31, 2007	—	$ —
Granted	2,746,671	$ 16.67
Forfeited	825,929	$ 16.58
Vested	178,500	$ 16.90
Nonvested — December 31, 2008	1,742,242	$ 16.69

The total fair value of our restricted stock that vested during the year ended December 31, 2008, was $3 million, and no restricted stock or restricted stock units vested during the years ended December 31, 2007 and 2006.

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

On August 10, 2008, in conjunction with his previously announced plans, Mr. May resigned as Chief Executive Officer and as a member of our Board of Directors. In accordance with the terms of his employment agreement, all non-qualified stock options and shares of restricted stock previously issued to Mr. May vested.

On August 12, 2008, Mr. Gregory L. Doody, our former Executive Vice President, General Counsel and Secretary, also left the Company. In accordance with the terms of his employment agreement, 64,100 non-qualified stock options with an exercise price of $16.90 as well as 100,600 shares of restricted stock previously issued to Mr. Doody vested.

As a result of the vesting of Mr. May's and Mr. Doody's restricted stock and non-qualified stock options, we recognized an additional $4 million in stock-based compensation expense during the year ended December 31, 2008.

14. Defined Contribution Plans

We maintain two defined contribution savings plans that are intended to be tax exempt under Sections 401(a) and 501(a) of the IRC. Our non-union plan generally covers employees who are not covered by a collective bargaining agreement, and our union plan covers employees who are covered by a collective bargaining agreement. We recorded expenses for these plans of $10 million, $9 million and $10 million for the years ending December 31, 2008, 2007 and 2006, respectively. Effective January 1, 2007, we amended our non-union plan to require newly hired employees to complete six months of service before becoming eligible to participate. Prior to the amendment, employees eligible to participate in the non-union plan could begin participating immediately upon hire.

Beginning January 1, 2008, the employer profit sharing contribution of 3% was eliminated and the employer matching contribution was increased to 100% of the first 5% of compensation a participant defers for the non-union plan and employee deferral limits were increased from 60% to 75% of compensation under both plans.

15. Capital Structure

Common Stock

Pursuant to the Plan of Reorganization, all shares of our common stock outstanding prior to the Effective Date were canceled, and we authorized the issuance of 485 million new shares of reorganized Calpine Corporation common stock. As of December 31, 2008, approximately 427 million shares have been distributed to holders of allowed unsecured claims against the U.S. Debtors, approximately 10 million are being held pending resolution of certain inter-creditor matters and approximately 48 million shares have been reserved for distribution to holders of disputed unsecured claims whose claims ultimately become allowed. See Note 3 for further discussion of the shares of reorganized Calpine Corporation common stock.

Our authorized common stock consists of 1.4 billion shares of Calpine Corporation common stock. Common stock issued as of December 31, 2008 and 2007 was 429,025,057 shares and 568,314,685 shares, respectively, at a par value of $0.001 per share. Common stock issued and outstanding as of December 31, 2008 and 2007 was 428,960,025 and 479,314,685, respectively.

The table below summarizes our common stock activity since our emergence from Chapter 11 on the Effective Date. As discussed in Note 3, all shares of our common stock outstanding prior to the Effective Date were canceled and common stock activity prior to the Effective Date is not presented below as it is no longer meaningful.

	Shares Issued	Shares Held in Treasury	Shares Held in Reserve	Inter-Creditor Disputes	Total
Implementation of our Plan of Reorganization	410,992,508	—	64,255,231	9,752,261	485,000,000
Resolution of claims	16,093,028	—	(16,093,028)	—	—
Exercise of warrants	21,499	—	—	—	21,499
Restricted stock, net of forfeitures	1,739,522	—	—	—	1,739,522
Vested restricted stock	178,500	(65,032)	—		113,468
Balance at December 31, 2008	429,025,057	(65,032)	48,162,203	9,752,261	486,874,489

Treasury Stock

As of December 31, 2008 we had withheld 65,032 shares of our common stock to satisfy federal, state and local income tax withholding requirements for employee restricted stock awards that vested in 2008 at a cost of approximately $1 million. There was no treasury stock at December 31, 2007.

Share Lending Agreement

In conjunction with the issuance of our 2014 Convertible Notes offering on September 30, 2004, we entered into a 10-year share lending agreement with DB London, under which we loaned DB London 89 million shares of newly issued Calpine common stock. DB London sold the entire 89 million shares on September 30, 2004, at a price of $2.75 per share in a registered public offering. We did not receive any of the proceeds of the public offering. DB London was required to and did return the loaned shares before the end of the 10-year term of the share lending agreement. During the years ended December 31, 2007 and 2006, DB London returned 50 million and 39 million shares, respectively. These returned shares were canceled at the Effective Date.

16. Commitments and Contingencies

Global Financial Crisis — The deterioration of global economic conditions has constricted access to capital and credit markets in the U.S. and worldwide, including within our industry, for us and our counterparties. These conditions will likely continue during 2009 and possibly longer. However, we believe the combination of our cash on hand, cash flow generated from operations and availability under our existing credit facilities is sufficient to enable us to meet all of our obligations as they come due.

Long Term Service Agreements — As of December 31, 2008, the total estimated commitments for LTSAs associated with turbines installed or in storage were approximately $95 million. These commitments are payable over the terms of the respective agreements, which range from one to ten years. LTSA future commitment estimates are based on the stated payment terms in the contracts at the time of execution and are subject to an annual inflationary adjustment. Certain of these agreements have terms that allow us to cancel the contracts for a fee. If we cancel such contracts, the estimated commitments remaining for LTSAs would be reduced. During the years ended December 31, 2008, 2007 and 2006, we recorded nil, nil and $2 million, respectively, of LTSA cancellation charges.

Power Plant Operating Leases — We have entered into certain long-term operating leases for power plants, expiring through 2049, including renewal options. Some of the lease agreements provide for renewal options at fair value, and some of the agreements contain customary restrictions on dividends, additional debt and further encumbrances similar to those typically found in project finance agreements. Payments on our operating leases which may contain escalation clauses or step rent provisions are recognized on a straight-line basis. Certain capital improvements associated with leased power plants may be deemed to be leasehold improvements and are amortized over the shorter of the term of the lease or the economic life of the capital improvement. Future minimum lease payments under these leases are as follows (in millions):

	Initial Year	2009	2010	2011	2012	2013	Thereafter	Total
Watsonville	1995	$ 4	$ —	$ —	$ —	$ —	$ —	$ 4
Greenleaf	1998	8	7	7	7	7	3	39
KIAC	2000	25	25	25	24	24	143	266
South Point	2001	10	10	67	5	5	221	318
Total		$ 47	$ 42	$ 99	$ 36	$ 36	$ 367	$ 627

During the years ended December 31, 2008, 2007 and 2006, rent expense for power plant operating leases amounted to $46 million, $54 million and $66 million, respectively. We guarantee $318 million of the total future minimum lease payments of our consolidated subsidiaries.

Production Royalties and Leases — We are committed under numerous geothermal leases and right-of-way, easement and surface agreements. The geothermal leases generally provide for royalties based on production revenue with reductions for property taxes paid. The right-of-way, easement and surface agreements are based on flat rates or adjusted based on CPI changes and are not material. Under the terms of most geothermal leases, the royalties accrue as a percentage of power revenues. Certain properties also have net profits and overriding royalty interests that are in addition to the land base lease royalties. Some lease agreements contain clauses providing for minimum lease payments to lessors if production temporarily ceases or if production falls below a specified level.

Production royalties for natural gas-fired and geothermal power plants for the years ended December 31, 2008, 2007 and 2006, were $33 million, $27 million and $25 million, respectively.

Office and Equipment Leases — We lease our corporate, regional and satellite offices as well as some of our office equipment under noncancellable operating leases expiring through 2014. Future minimum lease payments under these leases are as follows (in millions):

2009	$ 16
2010	12
2011	11
2012	11
2013	11
Thereafter	—
Total	$ 61

Lease payments are subject to adjustments for our pro rata portion of annual increases or decreases in building operating costs. During the years ended December 31, 2008, 2007 and 2006, rent expense for noncancellable operating leases amounted to $14 million, $10 million and $15 million, respectively.

Natural Gas Purchases — We enter into natural gas purchase contracts of various terms with third parties to supply natural gas to our natural gas-fired Cogeneration projects. The majority of our purchases are made in the spot market or under index-priced contracts. At December 31, 2008, we had future commitments of approximately $7.1 billion for natural gas purchases.

Guarantee Commitments — As part of our normal business operations, we enter into various agreements providing, or otherwise arranging, financial or performance assurance to third parties on behalf of our subsidiaries. Such arrangements include guarantees, standby letters of credit and surety bonds. These arrangements are entered into primarily to support or enhance the creditworthiness otherwise attributed to a subsidiary on a stand-alone basis, thereby facilitating the extension of sufficient credit to accomplish the subsidiaries' intended commercial purposes.

We routinely issue guarantees to third parties in connection with contractual arrangements entered into by our direct and indirect wholly owned subsidiaries in the ordinary course of such subsidiaries' respective business, including power and natural gas purchase and sale arrangements and contracts associated with the development, construction, operation and maintenance of our fleet of power plants.

At December 31, 2008, guarantees of subsidiary debt, standby letters of credit and surety bonds to third parties and guarantees of subsidiary operating lease payments and their respective expiration dates were as follows (in millions):

Guarantee Commitments	2009	2010	2011	2012	2013	Thereafter	Total
Guarantee of subsidiary debt[1]	$ 85	$ 73	$ 72	$ 70	$ 66	$ 701	$ 1,067
Standby letters of credit[2][4]	510	18	28	—	—	—	556
Surety bonds[3][4][5]	—	—	—	—	—	4	4
Guarantee of subsidiary operating lease payments[4]	10	10	67	5	5	221	318
Total	$ 605	$ 101	$ 167	$ 75	$ 71	$ 926	$ 1,945

(1) Represents Calpine Corporation guarantees of certain project financings, power plant operating leases, other miscellaneous debt and related interest. All of such guaranteed debt is recorded on our Consolidated Balance Sheets.

(2) The standby letters of credit disclosed above include those disclosed in Note 8.

(3) The majority of surety bonds do not have expiration or cancellation dates.

(4) These are off balance sheet obligations.

(5) As of December 31, 2008, $4 million of cash collateral is outstanding related to these bonds.

We routinely arrange for the issuance of letters of credit and various forms of surety bonds to third parties in support of our subsidiaries' contractual arrangements of the types described above and may guarantee the operating performance of some of our partially owned subsidiaries up to our ownership percentage. The letters of credit outstanding under various credit facilities support CES risk management and other operational and construction activities. In the event a subsidiary were to fail to perform its obligations under a contract supported by such a letter of credit or surety bond, and the issuing bank or surety were to make payment to the third party, we would be responsible for reimbursing the issuing bank or surety within an agreed timeframe, typically a period of one to ten days. To the extent liabilities are incurred as a result of activities covered by letters of credit or the surety bonds, such liabilities are included on our Consolidated Balance Sheets.

In connection with our purchase and sale agreements, we have frequently provided for indemnification by each of the purchaser and the seller, and/or their respective parent, to the counterparty for liabilities incurred as a result of a breach of a representation or warranty by the indemnifying party. These indemnification obligations generally have a discrete term and are intended to protect the parties against risks that are difficult to predict or impossible to quantify at the time of the consummation of a particular transaction.

Additionally, we and our subsidiaries from time to time assume other indemnification obligations in conjunction with transactions other than purchase or sale transactions. These indemnification obligations generally have a discrete term and are intended to protect our counterparties against risks that are difficult to predict or impossible to quantify at the time of the consummation of a particular transaction, such as the costs associated with litigation that may result from the transaction.

Litigation

We are party to various litigation matters, including regulatory and administrative proceedings arising out of the normal course of business, the more significant of which are summarized below. We review our litigation activities and determine if an unfavorable outcome to us is considered "remote," "reasonably possible" or "probable" as defined by GAAP. Where we have determined an unfavorable outcome is probable and is reasonably estimable, we have accrued for potential litigation losses. The ultimate outcome of each of these matters cannot presently be determined, nor can the liability that could potentially result from a negative outcome be reasonably estimated presently for every case. The liability we may ultimately incur with respect to any one of these matters in the event of a negative outcome may be in excess of amounts currently accrued with respect to such matters and, as a result of these matters, may potentially be material to our financial position or results of operations. During the pendency of our Chapter 11 cases through the Effective Date, pursuant to automatic stay provisions under the Bankruptcy Code and orders granted by the Canadian Court, all actions to enforce or otherwise effect repayment of liabilities preceding the Petition Date as well as all pending litigation against the Calpine Debtors generally were stayed. See Notes 2 and 3 for information regarding our Chapter 11 cases and CCAA proceedings. Following the Effective Date, pending actions to enforce or otherwise effect repayment of liabilities preceding the Petition Date, as well as pending litigation against the U.S. Debtors related to such liabilities generally have been permanently enjoined. Any unresolved claims will continue to be subject to the claims reconciliation process under the supervision of the U.S. Bankruptcy Court. However, certain pending litigation related to pre-petition liabilities may proceed in courts other than the U.S. Bankruptcy Court to the extent the parties to such litigation have obtained relief from the permanent injunction. In particular, certain pending actions against us are anticipated to proceed as described below. In addition to the Chapter 11 cases and CCAA proceedings (in connection with which certain of the matters described below arose), and the other matters described below, we are involved in various other claims and legal actions, including regulatory and administrative proceedings arising out of the normal course of our business. We do not expect that the outcome of such other claims and legal actions will have a material adverse effect on our financial position or results of operations.

Pre-Petition Litigation

Hawaii Structural Ironworkers Pension Fund v. Calpine, et al. This case was filed in San Diego County Superior Court on March 11, 2003, and later transferred, on a defense motion, to Santa Clara County Superior Court. Defendants in this case are Calpine Corporation, Peter Cartwright, Ann B. Curtis, John Wilson, Kenneth Derr, George Stathakis, Credit Suisse First Boston LLC, Banc of America Securities LLC, Deutsche Bank Securities, Inc. and Goldman Sachs & Co. The Hawaii Structural Ironworkers Pension Trust Fund alleges that the prospectus and registration statement for an April 2002 offering of Calpine Corporation securities contained false or misleading statements regarding: Calpine Corporation's actual financial results for 2000 and 2001; Calpine Corporation's projected financial results for 2002; Mr. Cartwright's alleged agreement not to sell or purchase shares within 90 days of the April 2002 offering; and Calpine Corporation's alleged involvement in "wash trades." The action in the Santa Clara County Superior Court was stayed against Calpine Corporation as a result of Calpine Corporation's Chapter 11 filing.

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

On July 1, 2008, a second amended complaint was filed against the same defendants. The second amended complaint repeated the allegations from the first amended complaint and added allegations that the above-described prospectus and registration statement included false or misleading statements related, among other things, to Calpine Corporation's cash balances and cash flow, construction projects and asset sales. The parties expect to complete fact discovery by the end of February 2009. Expert discovery will commence shortly thereafter. No trial date has been set in this action. We consider this lawsuit to be without merit and intend 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 our unitized stock fund. The consolidated complaint alleged that defendants breached their fiduciary duties under ERISA by permitting participants to buy and hold interests in our 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. 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 our fiduciary insurance carrier, the net proceeds of which would ultimately be deposited into individual plan members' accounts. The parties finalized the settlement agreement on March 7, 2008. Pursuant to the terms of the settlement, the Ninth Circuit Court of Appeals dismissed plaintiff's appeal without prejudice and remanded the case to the Northern District Court by order dated April 8, 2008. The Northern District Court granted preliminary approval on July 17, 2008, and gave final approval to the settlement at a fairness hearing on October 21, 2008. There were no objections to the settlement. Class members had 30 days after entry of judgment to appeal. That period has now run and, therefore, the settlement is final and the matter is now closed.

Pit River Tribe, et al. v. Bureau of Land Management, et al. On June 17, 2002, Pit River filed suit in the U.S. District Court for the Eastern District of California seeking to enjoin further exploration, construction and development of the Calpine Fourmile Hill Project at Glass Mountain. It challenges the validity of the decisions of the BLM and the Forest Service to permit the development of the project under leases previously issued by the BLM. The lawsuit also sought to invalidate the leases. Only declaratory and equitable relief were sought. Our answer was submitted on August 20, 2002. Cross-motions for summary judgment on all claims in the lawsuit were submitted in May and June 2003. The court held oral argument on the motions on September 10, 2003, and took the motions under advisement. Defendants' motions for summary judgment were granted on February 13, 2004, and the lawsuit was dismissed. Plaintiff filed an appeal to the Ninth Circuit Court of Appeals on April 15, 2004. Briefing on the appeal was completed on December 6, 2004. Following our Chapter 11 filing, we and Pit River filed a stipulation with the U.S. Bankruptcy Court to lift the automatic stay to allow the appeal to proceed with oral arguments, which were held on February 14, 2006. On November 5, 2006, the Ninth Circuit Court of Appeals issued a decision granting the plaintiffs relief by holding that the BLM had not complied with the National Environmental Policy Act, and other procedural requirements, when granting the lease extensions and, therefore, held that the lease extensions were invalid. On February 20, 2007, the federal appellees filed a Petition for Panel Rehearing of the November 5, 2006, order. We filed our Petition for Rehearing and Suggestion for Rehearing En Banc on February 21, 2007. On April 18, 2007, the Ninth Circuit Court of Appeals issued an order denying both the federal appellees and our Petitions for Rehearing. The remedy phase of the Ninth Circuit Court of Appeals' opinion had been stayed until Calpine Corporation's emergence from Chapter 11. Upon emergence from Chapter 11, we contacted the U.S. Department of Justice regarding possible remedies which could be argued to the District Court and prepared to file motions regarding how to implement the Ninth Circuit Court of Appeals mandate. On August 4, 2008, the U.S. Department of Justice filed a Request to Reopen Case and Proposed Order to Implement Appellate Mandate. The proposed order would remand the procedural defects identified by the Ninth Circuit Court of Appeals to the BLM to cure those defects and render a new decision whether or not to allow geothermal development at Glass Mountain, and if so, whether to extend Calpine Corporation's mineral leases. The plaintiffs assert that the two underlying leases have expired and curative action should not be allowed by the Court. On December 22, 2008, the U.S. District Court for the Eastern District of California adopted the U.S. Department of Justice's proposed order, which we supported. The order preserves our two Four Mile Hill mineral leases; allows us to submit our 1995 plan of utilization, or a new proposed plan of utilization; and allows the BLM to re-perform new environmental impact assessments and other procedural steps before making a second decision whether to extend those leases, and whether or how to allow development on the Four Mile Hill leases if they are extended.

In May 2004, Pit River and other interested parties filed two separate suits in the U.S. District Court for the Eastern District of California seeking to enjoin exploration, construction, and development of the Telephone Flat leases and proposed Project at Glass Mountain. These two related cases had been stayed until emergence. Similar to above, we are now in communication with the U.S. Department of Justice regarding these two cases; but, the cases remain mostly inactive pending the outcome of the litigation in the above described Pit Tribe case.

Post-Petition Litigation

Chapter 11 Related Litigation

Appeal of Confirmation Order. The Confirmation Order was entered by the U.S. Bankruptcy Court on December 19, 2007. Two motions to reconsider the Confirmation Order were filed by holders of shares of our common stock that were canceled on the Effective Date: the first was filed on December 28, 2007, by Elias A. Felluss and the second on December 31, 2007, by Compania Internacional Financiera, S.A., Coudree Global Equities Fund, Standard Bank of London and Leonardo Capital Fund SPC. On January 15, 2008, the U.S. Bankruptcy Court entered an order denying both of the motions to reconsider. On January 18, 2008, the shareholders who had filed the December 31, 2007, motion filed a notice of appeal to the SDNY Court and moved the U.S. Bankruptcy Court for a stay of the Confirmation Order pending appeal. Various additional shareholders subsequently filed joinders to the stay motion in the U.S. Bankruptcy Court. On January 24, 2008, the U.S. Bankruptcy Court entered an order denying the stay motion. The shareholders who filed the December 31, 2007, motion filed an emergency motion with the SDNY Court on January 25, 2008, seeking to expedite their appeal and stay the Confirmation Order pending appeal; their emergency motion was denied by the SDNY Court on February 1, 2008. In the meantime, on January 28, 2008, additional shareholders filed notices of appeal to the SDNY Court. On January 31, 2008, the Plan of Reorganization became effective and we emerged from Chapter 11. Despite the effectiveness of the Plan of Reorganization, the parties pursued their appeals in the

SDNY Court. On February 25, March 10, and March 14, 2008, the shareholder appellants filed their respective opening briefs. We filed a response on March 28, 2008, seeking to dismiss the appeals on grounds that (i) the appeals were equitably moot, (ii) the appellants had not made the threshold showing required to reverse the U.S. Bankruptcy Court; and (iii) the appeals all lack merit. The appellants filed their reply briefs on April 7, 2008. On June 6, 2008, the SDNY Court entered an order denying the appeals, finding that all of the appeals were equitably moot. One of the shareholders (Mr. Felluss) filed a motion for reconsideration, which was denied on June 24, 2008. On July 3, 2008, Mr. Felluss filed a notice of appeal with the Second Circuit. On August 8, 2008, Mr. Felluss filed a motion with the Second Circuit seeking to stay the expiration of the warrants, which the Second Circuit denied on August 27, 2008. The parties then proceeded to brief the merits of Mr. Felluss's appeal. Mr. Felluss filed his opening brief on September 5, 2008; we filed a response brief on October 6, 2008; and Mr. Felluss filed his reply on October 20, 2008. Rather than scheduling argument, on November 4, 2008, the Second Circuit asked whether the appeal could be decided on the written briefs without argument. We understand that Mr. Felluss has requested oral argument if it would be useful to the Court. We and the Creditors' Committee both notified the Court that, in their view, the appeal could be decided on the written briefs, without oral argument, but sought to participate at argument if granted to Mr. Felluss. We are waiting for the Second Circuit either to schedule oral argument or to issue its decision.

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 natural 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 alleged 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. The petition sought monetary damages for the value Rosetta did not pay Calpine Corporation for the assets it acquired, or, in the alternative, the return of the domestic oil and natural gas assets from Rosetta. On November 5, 2007, Rosetta filed its answer and six counterclaims, principally based on state contract and tort law. After substantial pre-trial document and deposition discovery and motion practice, on August 27, 2008, the U.S. Bankruptcy Court ordered the parties to participate in expedited mediation. On October 22, 2008, Calpine Corporation reached a settlement with Rosetta of all outstanding claims pursuant to which Rosetta paid Calpine Corporation $97 million, Calpine Corporation completed the transfer of certain other assets, the parties extended an existing natural gas purchase agreement for an additional ten years and the parties executed mutual releases. Of the $97 million settlement proceeds received, $79 million was associated with the certain other assets with a remaining net book value of approximately $42 million related to our domestic oil and gas assets we sold to Rosetta in 2005. The resulting $37 million gain is reflected as discontinuing operation in our 2008 Consolidated Statement of Operations. The remaining $18 million settlement proceeds received was associated with the agreed upon fraudulent conveyance of $12 million, which is included in reorganization items on our 2008 Consolidated Statement of Operations, and approximately $6 million in revenues collected by Rosetta during the litigation period on properties retained by us. The settlement was approved by the U.S. Bankruptcy Court on November 13, 2008, and closed on December 1, 2008.

Other Non-Chapter 11 Related Matters

Leone v. Calpine Corporation, et al. On May 22 and 29, 2008, respectively, two putative class action complaints (*Joseph Leone v. Calpine Corporation, et al.* and *Alan Laties v. Calpine Corporation, et al.*) were filed in state district court in Harris County, Texas against Calpine Corporation and its current directors, alleging that they either had breached, or would breach, their fiduciary duties in connection with Calpine Corporation's review of NRG's proposal for a stock-for-stock merger on May 14, 2008. Both lawsuits named the same persons as defendants with the exception of Kenneth Derr, who was named only in the first-filed Leone action. In general, the lawsuits sought to enjoin the defendants from accepting the NRG proposal, a declaration that the defendants had breached their fiduciary duties in connection with the NRG proposal, rescission of a transaction based on the terms of the NRG proposal, a court order requiring the defendants to comply with their fiduciary duties, damages, attorneys' fees, expenses, and court costs. On June 4, 2008, the two lawsuits were consolidated into a single action. On August 27, 2008, the parties filed a Stipulation and Agreed Motion to dismiss the consolidated action without prejudice. The Court approved the order of dismissal on October 22, 2008. Accordingly, the matter is now closed.

Texas City and Clear Lake Environmental Matters. As part of an internal review of our Texas City and Clear Lake Cogeneration power plants, we determined that our Acid Rain Program exemption under 40 CFR 72.6(b)(5) had ceased to apply and we were in violation of the requirements of the Acid Rain Program found in 40 CFR Parts 72-78. We were originally exempt from these provisions based upon each plant being a qualifying Cogeneration facility in operation before November 1990 with qualifying PPAs; however, the exemptions ceased to apply in 2002 for Texas City and 1999 for Clear Lake. To remedy the violation, we are required to report our SO_2 emissions to the EPA and purchase allowances and remit an excess emission fee for each ton over the allowance emitted since expiration of the exemption. We recorded estimated fees of $300,000 for Texas City and Clear Lake Cogeneration power plants. We self-reported these violations to the TCEQ and the EPA and we are working with these agencies to resolve these matters in a timely manner. Although these agencies have the authority and discretion to issue substantial fines that could be material, we do not believe that the penalties, if any, resulting from these matters will have a material adverse effect on our business, financial condition or results of operations based upon our analysis of the facts and circumstances and consideration of recent cases addressed by the agencies involved.

Communications with the SEC. We have been contacted by and have had meetings with the staff of the SEC regarding our financial statements and internal control over financial reporting as well as those of CalGen, a wholly owned subsidiary. We are cooperating with the SEC staff and have voluntarily provided information in response to their requests. We will continue to cooperate with the SEC with respect to these matters. A negative outcome of this investigation could require us to pay fines or penalties or satisfy other remedies under various provisions of the U.S. securities laws, and any of these outcomes could under certain circumstances have a material adverse effect on our business.

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

Although we do not consider it likely, the Lyondell debtors may exercise their right under the Bankruptcy Code to reject the lease, the energy services agreement and/or the facility services agreement. The potential damages to us if any or all of these agreements is rejected are uncertain. To the extent that any such damages would be recoverable under the laws of the State of Texas, the governing law under the agreements, they would be treated as an unsecured claim against the Lyondell debtors in bankruptcy.

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

17. Segment and Significant Customer Information

We are a wholesale power generation company and are primarily engaged in the ownership and operation of power plants in North America. We assess our business primarily on a regional basis due to the impact on our financial performance of the differing characteristics of these regions, particularly with respect to competition, regulation and other factors impacting supply and demand. Accordingly, our reportable segments are West (including geothermal), Texas, Southeast, North (including Canada) and Other. Our Other segment includes fuel management, TMG, and certain non-region specific natural gas marketing and optimization and other corporate activities.

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

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

	Year Ended December 31, 2008						
	West	Texas	Southeast	North	Other	Consolidation And Elimination	Total
Revenues from external customers	$ 4,229	$ 3,891	$ 1,273	$ 662	$ (118)	$ —	$ 9,937
Intersegment revenues	37	241	225	24	12	(539)	—
Total revenue	$ 4,266	$ 4,132	$ 1,498	$ 686	$ (106)	$ (539)	$ 9,937
Commodity Margin	1,191	815	300	280	124	—	2,710
Add: Mark-to-market commodity activity, net and other revenue[1]	27	114	4	2	(189)	(12)	(54)
Plant operating expense	316	257	125	106	128	(14)	918
Depreciation and amortization expense	188	123	68	55	5	(6)	433
Operating plant impairments	—	—	33	—	—	—	33
Other cost of revenue	57	1	22	25	9	—	114
Gross profit (loss)	657	548	56	96	(207)	8	1,158
Other operating expense							470
Income from operations							688
Interest expense, net of interest income							1,024
Other (income) expense, net							26
Loss before reorganization items, income taxes and discontinued operations							(362)
Reorganization items							(302)
Loss before income taxes and discontinued operations							$ (60)

	Year Ended December 31, 2007						
	West	Texas	Southeast	North	Other	Consolidation And Elimination	Total
Revenues from external customers	$ 3,668	$ 2,658	$ 1,040	$ 621	$ (11)	$ (6)	$ 7,970
Intersegment revenues	24	16	137	10	1	(188)	—
Total revenue	$ 3,692	$ 2,674	$ 1,177	$ 631	$ (10)	$ (194)	$ 7,970
Commodity Margin	1,196	500	268	283	(22)	—	2,225
Add: Mark-to-market commodity activity, net and other revenue[1]	40	77	9	—	(44)	(20)	62
Plant operating expense	306	158	118	82	96	(11)	749
Depreciation and amortization expense	207	121	79	54	4	(2)	463
Operating plant impairments	10	—	—	34	—	—	44
Other cost of revenue	49	—	31	34	27	(5)	136
Gross profit (loss)	664	298	49	79	(193)	(2)	895
Other operating expense							190
Income from operations							705
Interest expense, net of interest income							1,955
Other (income) expense, net							(139)
Loss before reorganization items and income taxes							(1,111)
Reorganization items							(3,258)
Income before income taxes							$ 2,147

	Year Ended December 31, 2006						
	West	Texas	Southeast	North	Other	Consolidation And Elimination	Total
Revenues from external customers	$ 2,996	$ 2,252	$ 1,213	$ 486	$ (7)	$ (3)	$ 6,937
Intersegment revenues	24	26	214	51	35	(350)	—
Total revenue	$ 3,020	$ 2,278	$ 1,427	$ 537	$ 28	$ (353)	$ 6,937
Commodity Margin	1,037	477	215	313	(21)	—	2,021
Add: Mark-to-market commodity activity, net and other revenue[1]	34	74	1	—	103	(48)	164
Plant operating expense	286	141	150	84	96	(7)	750
Depreciation and amortization expense	210	113	92	53	4	(2)	470
Operating plant impairments	—	—	—	53	—	—	53
Other cost of revenue	48	—	32	44	69	(21)	172
Gross profit (loss)	527	297	(58)	79	(87)	(18)	740
Other operating expense							276
Income from operations							464
Interest expense, net of interest income							1,175
Other (income) expense, net							18
Loss before reorganization items and income taxes							(729)
Reorganization items							972
Loss before income taxes							$ (1,701)

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(1) Mark-to-market commodity activity, is included in operating revenues and fuel and purchased energy expense on our Consolidated Statements of Operations.

Significant Customer

We did not have a customer that accounted for more than 10% of our annual consolidated revenues for the year ended December 31, 2008. For the years ended December 31, 2007 and 2006, we had one significant customer that accounted for more than 10% of our annual consolidated revenues: CDWR. CDWR revenues were $1.1 billion for both of the years ended December 31, 2007 and 2006. Our receivables from CDWR were $95 million at both December 31, 2007 and 2006. CDWR revenues were attributable to our West segment.

On December 7, 2007, we amended one of our PPAs with CDWR, which reduced our revenues with CDWR such that they were not a significant customer for the year ended December 31, 2008. The amendment modifies the PPA whereby we are relieved of our obligation to deliver 1,000 MW per hour at a fixed price of $59.60 per MWh through December 31, 2009, and instead agreed to provide CDWR 180 MW per hour of dispatchable capacity from Los Esteros Critical Energy Facility initially through December 31, 2009, with an extension through December 31, 2012. Under the amended PPA, we receive a monthly capacity payment which consists of $2 per kilowatt-month for the available capacity and a $4 per MWh variable operation and maintenance charge, subject to an annual escalation of 4%, for each MWh dispatched by CDWR.

18. Quarterly Consolidated Financial Data (unaudited)

Our quarterly operating results have fluctuated in the past and may continue to do so in the future as a result of a number of factors, including, but not limited to, our restructuring activities including asset sales, the completion of development projects, the timing and amount of curtailment of operations under the terms of certain PPAs, the degree of risk management and marketing, hedging and optimization activities, and variations in levels of production. Furthermore, the majority of the dollar value of capacity payments under certain of our PPAs are received during the months of May through October.

	Quarter Ended			
	December 31	September 30	June 30	March 31
	(in millions, except per share amounts)			
2008				
Operating revenues	$ 1,968	$ 3,190	$ 2,828	$ 1,951
Gross profit (loss)	177	534	476	(29)
Income (loss) from operations[1]	65	272	433	(82)
Income (loss) before discontinued operations	(132)	136	197	(214)
Discontinued operations, net of tax	23	—	—	—
Net income (loss)	$ (109)	$ 136	$ 197	$ (214)
Basic earnings (loss) per common share:				
Income (loss) before discontinued operations	$ (0.27)	$ 0.28	$ 0.41	$ (0.44)
Discontinued operations, net of tax	0.05	—	—	—
Net income (loss)	$ (0.22)	$ 0.28	$ 0.41	$ (0.44)
Diluted earnings (loss) per common share:				
Income (loss) before discontinued operations	$ (0.27)	$ 0.28	$ 0.41	$ (0.44)
Discontinued operations, net of tax	0.05	—	—	—
Net income (loss)	$ (0.22)	$ 0.28	$ 0.41	$ (0.44)
2007				
Operating revenues	$ 1,924	$ 2,324	$ 2,060	$ 1,662
Gross profit	158	427	242	68
Income from operations	104	382	200	19
Net income (loss)[2]	$ (142)	$ 3,794	$ (500)	$ (459)
Basic earnings (loss) per common share:				
Net income (loss)	$ (0.30)	$ 7.92	$ (1.04)	$ (0.96)
Diluted earnings (loss) per common share:				
Net income (loss)	$ (0.30)	$ 7.91	$ (1.04)	$ (0.96)

(1) As a result of the anticipated sale of Auburndale during 2008, we recorded an impairment charge of approximately $180 million, which is included in income from operations on our Consolidated Statements of Operations. See Note 5 for more information.

(2) During the third quarter of 2007, we entered into the Canadian Settlement Agreement and recorded a $4.1 billion credit in reorganization items on our Consolidated Statements of Operations.

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS

Description	Balance at Beginning of Year	Charged to Expense	Charged to Accumulated Other Comprehensive Loss	Reductions[1]	Other[2]	Balance at End of Year
			(in millions)			
Year ended December 31, 2008						
Allowance for doubtful accounts	$ 54	$ 15	$ —	$ (32)	$ —	$ 37
Allowance for doubtful accounts with related party Canadian Debtors and other foreign entities	10	—	—	(10)	—	—
Reserve for notes receivable	39	—	—	(39)	—	—
Reserve for interest and notes receivable with related party Canadian Debtors and other foreign entities	83	—	—	(83)	—	—
Deferred tax asset valuation allowance	2,401	(194)	—	—	478	2,685
Year ended December 31, 2007						
Allowance for doubtful accounts	$ 32	$ 52	$ —	$ (30)	$ —	$ 54
Allowance for doubtful accounts with related party Canadian Debtors and other foreign entities	71	3	—	(64)	—	10
Reserve for notes receivable	36	3	—	—	—	39
Reserve for interest and notes receivable with related party Canadian Debtors and other foreign entities	227	—	—	(144)	—	83
Gross reserve for California Refund Liability	13	—	—	(13)	—	—
Deferred tax asset valuation allowance	2,321	565	—	(485)	—	2,401
Year ended December 31, 2006						
Allowance for doubtful accounts	$ 13	$ 21	$ —	$ (2)	$ —	$ 32
Allowance for doubtful accounts with related party Canadian Debtors and other foreign entities	55	24	—	(8)	—	71
Reserve for notes receivable	32	4	—	—	—	36
Reserve for interest and notes receivable with related party Canadian Debtors and other foreign entities	228	—	—	—	(1)	227
Gross reserve for California Refund Liability	13	—	—	—	—	13
Reserve for investment in Androscoggin Energy Center	5	—	—	(5)	—	—
Deferred tax asset valuation allowance	1,639	682	—	—	—	2,321

(1) Represents write-offs of accounts considered to be uncollectible and recoveries of amounts previously written off or reserved.

(2) The adjustment of $478 million represents the additions resulting from our reconsolidation of our Canadian and other foreign subsidiaries and the difference in the amounts disclosed in our prior 10-K and the final amount as filed in our 2007 tax return. There was no impact to our Statement of Operations for the year ended December 31, 2008.

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

Board of Directors

William J. Patterson*
Chairman of the Board
Managing Director, SPO Partners & Co.

Frank Cassidy†
Retired, Public Service Enterprise Group, Inc.

Jack A. Fusco
President and Chief Executive Officer, Calpine Corp.

Robert Hinckley* ¤
Retired, Xilinx, Inc.

David Merritt ¤
Senior Vice President and Chief Financial Officer, iCRETE LLC

W. Benjamin Moreland ¤
President and Chief Executive Officer, Crown Castle International Corp.

Robert A. Mosbacher, Jr.
Former President and Chief Executive Officer, Overseas Private Investment Corporation

Denise M. O'Leary*†
Private Venture Capital Investor

J. Stuart Ryan†
Founding Owner and President, Rydout LLC

* Nominating and Corporate Governance Committee
† Compensation Committee
¤ Audit Committee

Executive Management

Jack A. Fusco
President and Chief Executive Officer

W. Thaddeus Miller
Executive Vice President, Chief Legal Officer and Corporate Secretary

Thad Hill
Executive Vice President and Chief Commercial Officer

Zamir Rauf
Executive Vice President and Chief Financial Officer

Gary M. Germeroth
Executive Vice President and Chief Risk Officer

Jim D. Deidiker
Senior Vice President and Chief Accounting Officer

General Information

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717 Texas Avenue, Suite 1000
Houston, Texas 77002
(713) 830-2000
www.calpine.com

Investor Relations
Calpine Corporation Investor Relations
(713) 830-8775
investor-relations@calpine.com

Independent Auditor
PricewaterhouseCoopers LLP
Houston, Texas

Transfer Agent
Computershare, Inc.
P.O. Box 43078
Providence, RI 02940-3078
877-745-9351

Certifications
Jack A. Fusco and Zamir Rauf have provided certifications to the Securities and Exchange Commission as required by section 302 of the Sarbanes-Oxley Act of 2002. These certifications are included as exhibits 31.1 and 31.2 of the company's Form 10-K for the year ended December 31, 2008.

On March 2, 2009, Jack A. Fusco submitted an annual certification to the New York Stock Exchange ("NYSE") that stated he was not aware of any violation by the company of the NYSE corporate governance listing standards.

Form 10-K
The Company's Annual Report on Form 10-K for the year ended December 31, 2008, as filed with the Securities and Exchange Commission, is included in this report. Additional copies may be obtained without charge by writing:

Calpine Corporation
Attn: Investor Relations
717 Texas Avenue, Suite 1000
Houston, Texas 77002

Annual Meeting
The Annual Meeting of Shareholders of Calpine Corporation will be held on Thursday, May 7, 2009 at 10:00 am CT at the Hilton Americas – Houston hotel located at 1600 Lamar Street, Houston Texas 77010. All shareholders are cordially invited to attend.

Stock Information
Calpine Corporation's common stock is listed on the NYSE under the symbol CPN.

Forward-Looking Statement
Certain statements made in this Annual Report by or on behalf of the Company that are not historical facts are intended to be forward-looking statements within the meaning of the safe harbor provisions of the Private Securities Litigation Reform Act of 1995. These statements are based on assumptions that the Company believes are reasonable; however, many important factors, as discussed under "Forward-Looking Statements" in the Company's Form 10-K for the year ended December 31, 2008, could cause the Company's results in the future to differ materially from the forward-looking statements made herein and in any other documents or oral presentations made by or on behalf of the Company.

CALPINE®
NYSE CPN

Calpine Corporation
717 Texas Avenue, Suite 1000
Houston, Texas 77002
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On the front cover:

Top – Los Esteros Critical Energy Facility, Calif., Peaking facility
Middle – The Geyers, Calif., Geothermal facility
Bottom – Metcalf Energy Center, Calif., Combined-cycle facility
Far bottom right – Kennedy International Airport Power Plant, New York, Combined-cycle cogeneration facility