CALPINE®
NYSE CPN

A Generation Ahead, *today*

2011 ANNUAL REPORT

CLEAN MODERN EFFICIENT FLEXIBLE
POWER GENERATION

A generation ahead, today.

Calpine's power generation portfolio contains critical pieces needed to help solve the puzzle of America's clean energy future. Our clean, modern, efficient and flexible natural gas-fired generation fleet is the compelling environmental, economic and operational choice.

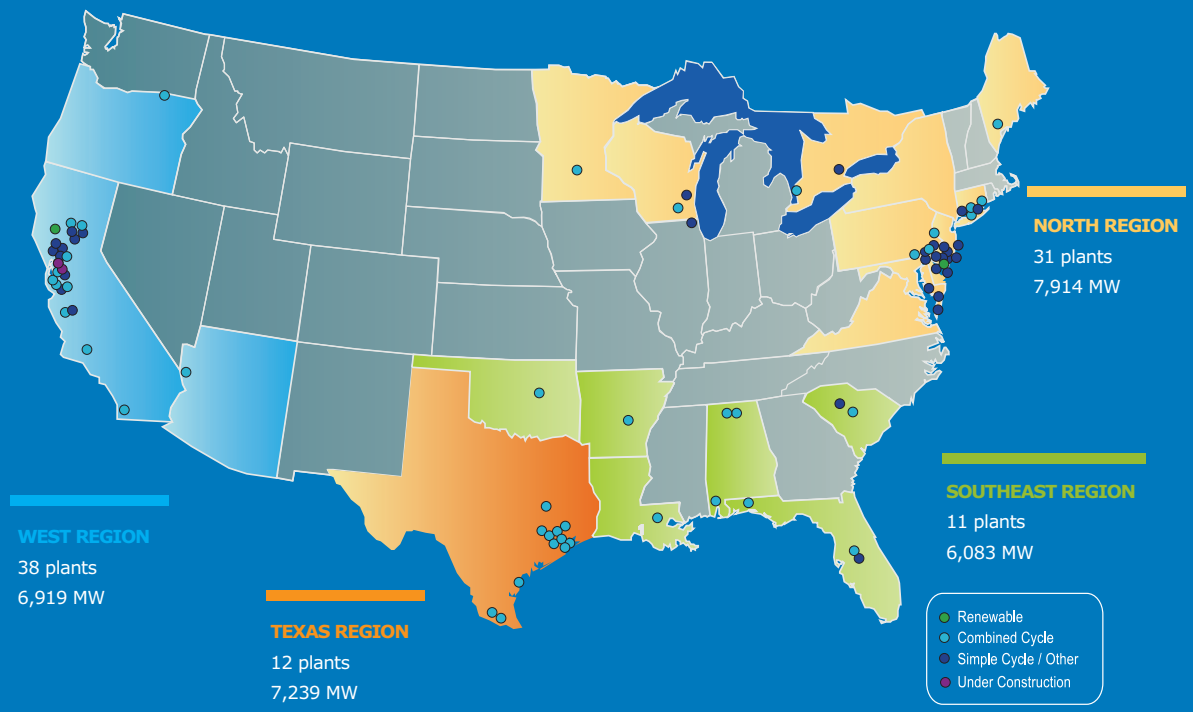
Environmental stewardship is a guiding principle of our company. The air emissions from our natural gas-fired plants contain no mercury, a fraction of the sulfur dioxide and nitrogen oxides and less than half the carbon emissions compared to coal-fired generation. Our geothermal power plants, called The Geysers and located in Northern California, are the ideal renewable generation source, providing reliable power around the clock.

The discovery of vast reserves of natural gas in America and the technological advances in extraction have resulted in a low and less volatile natural gas price environment that is forecast to prevail for the foreseeable future. The realization of this secure, affordable and clean fossil fuel should make it the compelling economic choice for power generation for years to come.

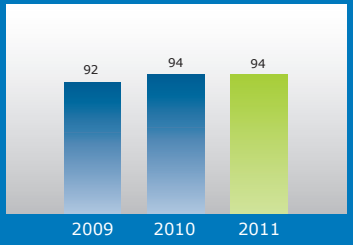
Operationally, our existing natural gas fleet has two meaningful advantages. We have excess capacity, giving us the ability to increase sales volume as our customers and the power markets move to natural gas generation as the lowest cost provider. Additionally, the flexibility of our fleet is critical to the operation of the electric grid, particularly as grid operators are challenged to integrate intermittent renewable resources.

As the new economics of natural gas-fired generation take hold and as environmental imperatives force older coal-fired generation to retire, Calpine's clean, modern, efficient and flexible fleet stands ready to lead our nation's march toward a cleaner energy future.

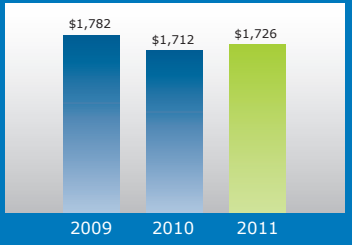
National Portfolio of 28,155 MW



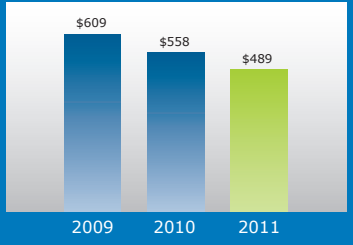
GENERATION VOLUME
(Million MWh)



ADJUSTED EBITDA
($ millions)



ADJUSTED RECURRING FREE CASH FLOW
($ millions)



DEAR FELLOW SHAREHOLDERS

CALPINE — America's largest independent power producer and a name synonymous with *clean, modern, efficient, flexible power generation.* That's who we are and — as clean air policies take root, coal-to-gas switching continues or the economy strengthens — we expect demand for our clean, flexible and efficient generation to increase, leading to more success in delivering greater shareholder value to you.

In 2011, we delivered solid operational and financial results, achieved commercial successes and continued financially disciplined growth. Last year we:

- Generated over 94 million megawatt hours (MWhs) of electricity for our customers;
- Originated nearly 1,400 MWs of new long-term contracts at our Pastoria, Carville and Auburndale power plants;
- Completed 10 turbine upgrades for a total of 91 MWs of incremental capacity;
- Commenced construction on a net 584 MWs at our Russell City and Los Esteros power plants and secured attractive related financing;
- Launched a $300 million share repurchase program; and
- For the third consecutive year, achieved shareholder return in excess of 20%.

Looking ahead to 2012 and beyond, we remain committed to delivering long-term shareholder value. Calpine's competitive, efficient and flexible power generation fleet is benefitting from the current low natural gas price environment, which is driving unprecedented amounts of coal-to-gas switching. Furthermore, we are encouraged by factors specific to each of our core markets:

- In ERCOT, supply and demand are tight and regulators are working to ensure that wholesale power prices adequately reflect scarcity price signals.
- In PJM, supply and demand should tighten as we reach mid-decade as a result of power plant retirements being driven by clean air regulations and coal-to-gas switching.
- In California, regulators are increasingly focused on the need to fairly compensate existing and flexible generation that is critical to the integration of intermittent renewable resources.
- In the Southeast, utility customers appear increasingly interested in long-term power purchase agreements that attractively monetize our power plants.

Finally, we will continue to look for opportunities to monetize current assets giving us flexibility to reallocate our capital in a manner that drives shareholder value over the long term.

To be sure, the road ahead has its challenges, including forward power prices that are currently unreflective of market fundamentals, state interference with competitive wholesale markets and slowdowns on clean air regulations. Yet we expect to continue to deliver shareholder value through operational excellence, execution on commercial opportunities with our customers, pursuit of financially disciplined growth and optimization of our balance sheet — in short, by keeping Calpine a generation ahead, today.

Thank you for your continued support.

Sincerely,

J. Stuart Ryan
Chairman of the Board

Jack A. Fusco
President and Chief Executive Officer

CLEAN

As part of Calpine's national effort to support Earth Day projects in local communities, employees from our Baytown Energy Center plant trees at the Baytown Nature Center.

Socrates Geothermal Power Plant
The Geysers
Sonoma County, CA

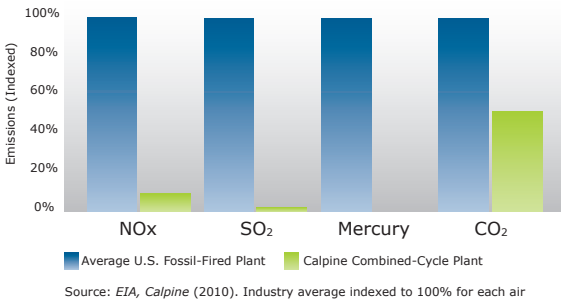
Why CLEAN *matters.*

Since Calpine's founding in 1984, we have proactively invested in environmentally responsible technology with good reason. We believed from the outset that cleaner power was the right thing to do for our communities. We also believed that it would be the right thing to do for our shareholders as federal and state regulatory policy focused on cleaner air and water. That vision is becoming a reality, with air emissions and water intake regulations primed to significantly impact the power generation industry over the balance of this decade.

While other generators grapple with decisions about whether to invest in costly retrofits or to retire, Calpine — with our fleet of low-emission natural gas-fired and renewable geothermal plants — stands ready and well positioned to respond to stricter environmental regulations. Our Geysers geothermal plants in Northern California, which supply reliable renewable electricity around the clock, produce approximately 20% of the renewable power in California. Our natural gas-fired fleet emits a fraction of the hazardous air pollutants and greenhouse gases that coal-fired plants do and features virtually no once-through cooling technology, minimizing impacts on marine life.

In other words, *CLEAN* matters because our investment decisions are not environmentally mandated. We have the discretion to deploy our capital into high-return growth opportunities or to return it to our shareholders, rather than being forced to invest it in major environmental compliance obligations.

Fractional Air Emissions Compared to Industry Average



Source: *EIA, Calpine* (2010). Industry average indexed to 100% for each air pollutant shown.

Calpine takes pride in its environmental stewardship. Among our IPP peers, we produce the most electricity, year in and year out, yet we emit the fewest pollutants per MWh. We were the first power producer to earn the distinction of Climate Action Leader and have been named by the Natural Resources Defense Council as among the cleanest power generation companies in the United States.

MODERN

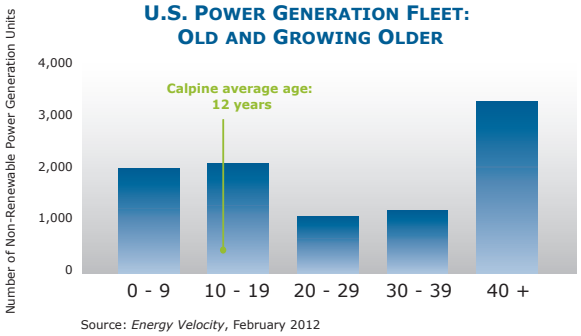
Our modern power plants are operated and maintained by a team of expert technicians who take great pride in serving our customers.

Brazos Valley Energy Center
Richmond, TX

Why MODERN *matters.*

With an average age of approximately 12 years, Calpine's fleet is the youngest among pure-play independent power producers. It features modern technology that, while fully capable of running under baseload conditions, has historically been cycled to follow power demand as it peaks during certain months of the year and certain times of the day. Meanwhile, across the U.S., over 20% of the nation's fossil-based power generation capacity is over 40 years old — well past its useful economic life. Much of this older generation is confronted with the need for significant maintenance requirements, often accompanied by significant environmental compliance requirements, and is likely to retire. Analysts estimate that 40,000 – 60,000 MWs of power generation capacity will be retired this decade, much of it in the eastern United States. Calpine's modern fleet stands ready to fill the void from these retirements, able to produce significantly more electricity from our existing fleet with virtually no incremental investment required.

MODERN matters because our fleet is already equipped for the future. We maintain our fleet to protect that advantage, preserving our ability to offer best-in-class technology.



Source: *Energy Velocity*, February 2012

The U.S. power generation infrastructure continues to age: nearly 3,500 non-renewable power generation units in the U.S. are 40 or more years old and are environmentally and technologically obsolete. By contrast, Calpine's fleet is an average of 12 years old and features current technology that enhances our ability to serve our customers. We continue to invest in our equipment to ensure that our fleet remains modern — from our recurring maintenance program to our ongoing turbine upgrades to our construction projects at our Russell City and Los Esteros power plants.

EFFICIENT

Our Osprey Energy Center, located in Auburndale, FL, features efficient combined-cycle technology.

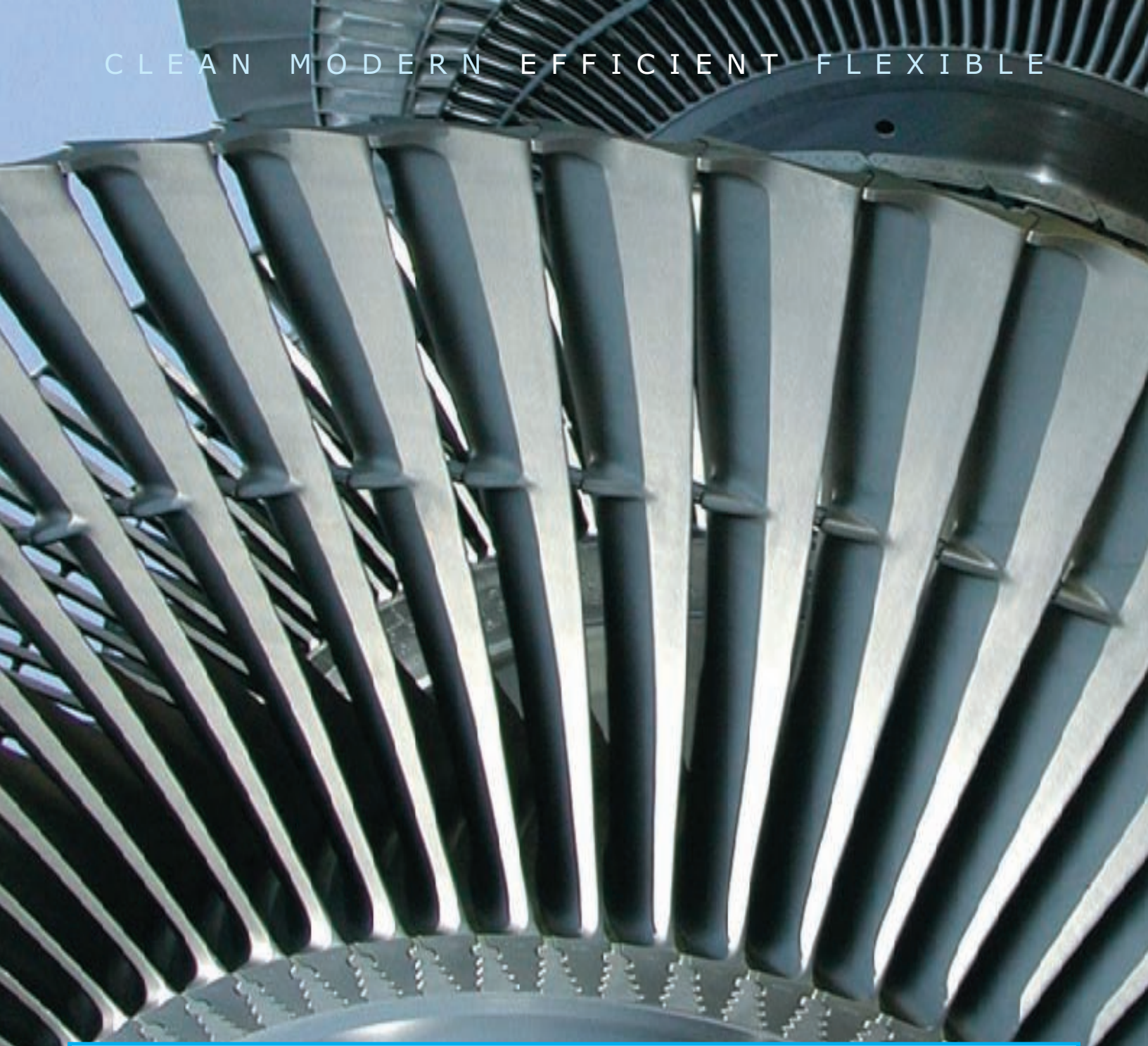
Why EFFICIENT *matters.*

Calpine's fleet of natural gas-fired, combined-cycle power plants is among the most efficient in the power generation sector at converting fossil fuel into power. Since fossil generation typically sets the marginal power price in competitive markets, power conversion efficiency drives profitability. In 2011, our fleetwide power conversion efficiency of 46% was nearly 50% more efficient than older technology natural gas-fired power plants and coal-fired power plants.

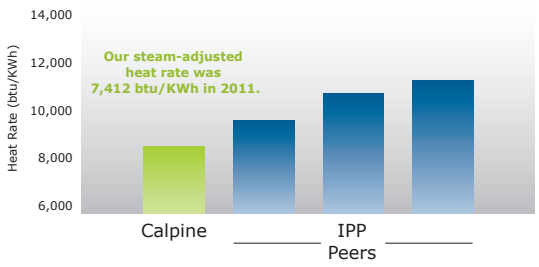
Our exceptional efficiency is also impacted by the fact that we operate the largest fleet of cogeneration power plants in the U.S. These plants produce steam as well as power, allowing them to achieve substantially higher efficiency rates than other power production technologies. In addition, our investment in cogeneration technology allows us to serve domestic manufacturing and processing companies with low-cost energy, providing them an advantage in the global marketplace.

Combining our superior efficiency with a low natural gas price environment places us among the lowest-cost fossil generation providers in the markets we serve, thereby enabling us to capitalize on the challenges that the sector otherwise faces under low natural gas price conditions.

In sum, *EFFICIENT* matters because it directly impacts our volume of generation and our profitability, particularly as natural gas-fired generation continues to displace coal. Being efficient means being more competitive, more agile and more resilient to low natural gas prices.



Most Efficient among IPP Peers



Source: *Energy Velocity* (2010). Not adjusted for steam, and excluding non-fossil fuel generation. Calpine steam-adjusted heat rate does not include peakers.

As one of the largest operators of combined-cycle technology in the U.S., Calpine features a highly efficient fleet with an expert team of operators: in 2011, two of our plants — Decatur and Osprey — were named finalists in the *Combined Cycle Journal* Best Practices Awards for their contributions to improvements in combined-cycle plant operations. Calpine also operates the nation's largest fleet of cogeneration power plants, which further improves our efficiency. Our fleetwide heat rate (a measure of the efficiency with which fuel is converted into power) leads the IPP sector.

FLEXIBLE

Supported by our commercial operations team, our plant operators utilize state-of-the-art technology to dispatch our fleet economically and dynamically in response to varying market conditions.

Why FLEXIBLE *matters.*

Flexibility is an important distinction among power plants that entails several qualities, most notably the ability to stop and start turbines quickly and frequently. A typical baseload coal-fired power generation plant can take 12 – 16 hours to start. In contrast, a typical combined-cycle natural gas-fired power plant typically can take 1 – 2 hours to start, while natural gas-fired peaking units can start within 10 – 30 minutes to respond to urgent needs for power. In addition to featuring these quick start capabilities, our flexible fleet also offers load-following, voltage support and other ancillary services that are critical for maintaining grid reliability.

Calpine's fleet of natural gas-fired power plants is among the largest in the U.S. and provides critical flexibility to the markets where we operate. The need for reliable, flexible power generation has become increasingly important, especially in areas that are dependent upon intermittent renewables (like solar and wind) or potentially unreliable demand response resources or both for supply. In 2011, we delivered 98% fleetwide starting reliability across a record number of turbine starts, demonstrating our excellence in providing flexible services.

Being *FLEXIBLE* matters because our nation's varying power needs — including variability driven by weather and intermittent resources — drive the necessity for reliably responsive generation. We are proud of the flexibility offered by our fleet and believe our customers value it in their resource planning decisions.

Proven Operational Flexibility: A Telling Sign for the Future

Our natural gas-fired fleet features baseload, intermediate and peaking capacity. Our Mid-Atlantic combined-cycle fleet demonstrates these varying capabilities: in 2008 and 2009, these plants were dispatched primarily as peaking capacity; in 2010 and 2011, under Calpine ownership, they operated more as intermediate capacity; and in early 2012, as gas prices declined significantly, these plants began operating as baseload capacity. The flexibility of our fleet is a distinct competitive advantage.

Hay Road Energy Center
Wilmington, DE

CLEAN MODERN EFFICIENT FLEXIBLE
POWER GENERATION

POWERED BY THE BEST

Our fleet is a generation ahead, today. Our ability to execute on our plan to optimize our fleet is driven by the people of Calpine — from our highly skilled and focused power plant and facilities employees who have consistently delivered strong operating results, to our maintenance technicians who are regarded as among the very best turbine maintenance and repair engineers in the world, to our commercial origination and operations teams who expertly help monetize our operating assets, to the rest of our team who every day remain focused and dedicated to our mission.

The people of Calpine are and will remain successful at delivering value to our customers, our communities and you, our shareholders. With the strength of our fleet, the drive of our employees and the support of our communities, we are well positioned to respond to the challenges shaping the power generation sector of the future.

CALPINE®

NYSE CPN

A GENERATION AHEAD, *today*

2011 FORM 10-K

CLEAN MODERN EFFICIENT FLEXIBLE
POWER GENERATION

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-K

[X] ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2011

[ ] TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from to

Commission File No. 001-12079

Calpine Corporation

(A Delaware Corporation)

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

717 Texas Avenue, Suite 1000, Houston, Texas 77002

Telephone: (713) 830-2000

Not Applicable

(Former Address)

Securities registered pursuant to Section 12(b) of the Act:
Calpine Corporation Common Stock, $0.001 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 whether the registrant has submitted electronically and posted on its corporate Website, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes [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 [ ]	Smaller reporting company [ ]
(Do not check if a smaller reporting company)	

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

State the aggregate market value of the voting and non-voting common equity held by non-affiliates of the registrant as of June 30, 2011, the last business day of the registrant's most recently completed second fiscal quarter: approximately $4,491 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 [ ]

Indicate the number of shares outstanding of each of the registrant's classes of common stock, as of the latest practicable date: Calpine Corporation: 481,338,627 shares of common stock, par value $0.001, were outstanding as of February 7, 2012.

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 2012 Annual Meeting of Shareholders are incorporated by reference into Part III (Items 11, 12, 13, 14 and portions of Item 10)

CALPINE CORPORATION AND SUBSIDIARIES

FORM 10-K

ANNUAL REPORT
For the Year Ended December 31, 2011

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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. 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
2017 First Lien Notes	The $1.2 billion aggregate principal amount of 7.25% senior secured notes due 2017, issued October 21, 2009, in exchange for a like principal amount of term loans under the First Lien Credit Facility
2019 First Lien Notes	The $400 million aggregate principal amount of 8.0% senior secured notes due 2019, issued May 25, 2010
2020 First Lien Notes	The $1.1 billion aggregate principal amount of 7.875% senior secured notes due 2020, issued July 23, 2010
2021 First Lien Notes	The $2.0 billion aggregate principal amount of 7.50% senior secured notes due 2021, issued October 22, 2010
2023 First Lien Notes	The $1.2 billion aggregate principal amount of 7.875% senior secured notes due 2023, issued January 14, 2011
AB 32	California Assembly Bill 32
Adjusted EBITDA	EBITDA as adjusted for the effects of (a) impairment charges, (b) major maintenance expense, (c) operating lease expense, (d) unrealized gains or losses on commodity derivative mark-to-market activity, (e) adjustments to reflect only the Adjusted EBITDA from our unconsolidated investments, (f) stock-based compensation expense, (g) gains or losses on sales, dispositions or retirements of assets, (h) non-cash gains and losses from foreign currency translations, (i) gains or losses on the repurchase or extinguishment of debt, (j) Conectiv acquisition-related costs, (k) Adjusted EBITDA from our discontinued operations and (l) other extraordinary, unusual or non-recurring items
AOCI	Accumulated Other Comprehensive Income
Average availability	Represents the total hours during the period that our plants were in-service or available for service as a percentage of the total hours in the period
Average capacity factor, excluding peakers	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 average total MW in operation, excluding peakers, during the period by (ii) the total hours in the period
Bankruptcy Code	U.S. Bankruptcy Code
BLM	Bureau of Land Management of the U.S. Department of the Interior
Blue Spruce	Blue Spruce Energy Center, LLC, formerly an indirect, wholly owned subsidiary that owned Blue Spruce Energy Center, a 310 MW natural gas-fired, peaker power plant located in Aurora, Colorado, which was sold on December 6, 2010

ABBREVIATION	DEFINITION
Broad River	Broad River Energy Center, an 847 MW natural gas-fired, peaker power plant located in Gaffney, South Carolina
Btu	British thermal unit(s), a measure of heat content
CAA	Federal Clean Air Act, U.S. Code Title 42, Chapter 85
CAIR	Clean Air Interstate Rule
CAISO	California Independent System Operator
CalGen	Calpine Generating Company, LLC, an indirect, wholly owned subsidiary
CalGen Third Lien Debt	Together, the $680 million Third Priority Secured Floating Rate Notes Due 2011, issued by CalGen and CalGen Finance Corp.; and the $150 million 11.5% Third Priority Secured Notes Due 2011, issued by CalGen and CalGen Finance Corp., in each case repaid on March 29, 2007
Calpine BRSP	Calpine BRSP, LLC
Calpine Equity Incentive Plans	Collectively, the Director Plan and the Equity Plan, which provide for grants of equity awards to Calpine employees and non-employee members of Calpine's Board of Directors
Cap-and-trade	A government imposed emissions reduction program that would place a cap on the amount of emissions that can be emitted from certain sources, such as power plants. In its simplest 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 emissions during each applicable period. After allowances have been distributed or auctioned, they can be transferred or traded
CARB	California Air Resources Board
CCFC	Calpine Construction Finance Company, L.P., an indirect, wholly owned subsidiary
CCFC Finance	CCFC Finance Corp.
CCFC Guarantors	Hermiston Power LLC and Brazos Valley Energy LLC, wholly owned subsidiaries of CCFC
CCFC Notes	The $1.0 billion aggregate principal amount of 8.0% Senior Secured Notes due 2016 issued May 19, 2009, by CCFC and CCFC Finance
CCFC Old Notes	The $415 million total aggregate principal amount of Second Priority Senior Secured Floating Rate Notes Due 2011 issued by CCFC and CCFC Finance, comprising $365 million aggregate principal amount issued August 14, 2003, and $50 million aggregate principal amount issued September 25, 2003, and redeemed, in each case, on June 18, 2009
CCFC Refinancing	The issuance of the CCFC Notes on May 19, 2009, pursuant to Rule 144A and Regulation S under the Securities Act, and the related transactions including repayment of the CCFC Term Loans and the redemption of the CCFC Old Notes and CCFCP Preferred Shares
CCFC Term Loans	The $385 million First Priority Senior Secured Institutional Term Loans due 2009 borrowed by CCFC under the Credit and Guarantee Agreement, dated as of August 14, 2003, among CCFC, the guarantors party thereto, and Goldman Sachs Credit Partners L.P., as sole lead arranger, sole bookrunner, administrative agent and syndication agent, and repaid on May 19, 2009
CCFCP	CCFC Preferred Holdings, LLC

ABBREVIATION	DEFINITION
CCFCP Preferred Shares	The $300 million of six-year redeemable preferred shares due 2011 issued by CCFCP and redeemed on or before July 1, 2009
CDHI	Calpine Development Holdings, Inc., an indirect, wholly owned subsidiary
CEHC	Conectiv Energy Holding Company, LLC, a wholly owned subsidiary of Conectiv
CES	Calpine Energy Services, L.P.
CFTC	U.S. Commodities Futures Trading Commission
Chapter 11	Chapter 11 of the U.S. Bankruptcy Code
CO_2	Carbon dioxide
COD	Commercial operations date
Cogeneration	Using a portion or all of the steam generated in the power generating process to supply a customer with steam for use in the customer's operations
Commodity expense	The sum of our expenses from fuel and purchased energy expense, fuel transportation expense, transmission expense and cash settlements from our marketing, hedging and optimization activities including natural gas transactions hedging future power sales that are included in our mark-to-market activity in fuel and purchased energy expense, but excludes the unrealized portion of our mark-to-market activity
Commodity Margin	Non-GAAP financial measure that includes power and steam revenues, sales of purchased power and physical natural gas, capacity revenue, REC revenue, sales of surplus emission allowances, transmission revenue and expenses, fuel and purchased energy expense, fuel transportation expense, RGGI compliance and other environmental costs, and cash settlements from our marketing, hedging and optimization activities including natural gas transactions hedging future power sales that are included in mark-to-market activity, but excludes the unrealized portion of our mark-to-market activity and other revenues
Commodity revenue	The sum of our revenues from power and steam sales, sales of purchased power and physical natural gas, capacity revenue, REC revenue, sales of surplus emission allowances, transmission revenue, and cash settlements from our marketing, hedging and optimization activities that are included in our mark-to-market activity in operating revenues, but excludes the unrealized portion of our mark-to-market activity
Company	Calpine Corporation, a Delaware corporation, and its subsidiaries
Conectiv	Conectiv, LLC, a wholly owned subsidiary of PHI
Conectiv Acquisition	The acquisition of all of the membership interests in CEHC pursuant to the Conectiv Purchase Agreement on July 1, 2010, whereby we acquired all of the power generation assets of Conectiv from PHI, which included 18 operating power plants and York Energy Center that was under construction and achieved COD on March 2, 2011, with 4,491 MW of capacity
Conectiv Purchase Agreement	Purchase Agreement by and among PHI, Conectiv, CEHC and NDH dated as of April 20, 2010
Corporate Revolving Facility	The $1.0 billion aggregate amount revolving credit facility credit agreement, dated as of December 10, 2010, among Calpine Corporation, Goldman Sachs Bank USA, as administrative agent, Goldman Sachs Credit Partners L.P., as collateral agent, the lenders party thereto and the other parties thereto
CPUC	California Public Utilities Commission
Creed	Creed Energy Center, LLC

ABBREVIATION	DEFINITION
Director Plan	The Amended and Restated Calpine Corporation 2008 Director Incentive Plan
Dodd-Frank Act	The Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010
EBITDA	Earnings before interest, taxes, depreciation and amortization
Effective Date	January 31, 2008, the date on which the conditions precedent enumerated in the Plan of Reorganization were satisfied or waived and the Plan of Reorganization became effective
EIA	Energy Information Administration of the U.S. Department of Energy
Emergence Date Market Capitalization	The weighted average trading price of Calpine Corporation's common stock over the 30-day period following the date on which it emerged from Chapter 11 bankruptcy protection, as defined in and calculated pursuant to Calpine Corporation's amended and restated certificate of incorporation and reported in its Current Report on Form 8-K filed with the SEC on March 25, 2008
EPA	U.S. Environmental Protection Agency
Equity Plan	The Amended and Restated Calpine Corporation 2008 Equity Incentive Plan
ERCOT	Electric Reliability Council of Texas
EWG(s)	Exempt wholesale generator(s)
Exchange Act	U.S. Securities Exchange Act of 1934, as amended
FASB	Financial Accounting Standards Board
FDIC	U.S. Federal Deposit Insurance Corporation
FERC	U.S. Federal Energy Regulatory Commission
First Lien Credit Facility	Credit Agreement, dated as of January 31, 2008, as amended by the First Amendment to Credit Agreement and Second Amendment to Collateral Agency and Intercreditor Agreement, dated as of August 20, 2009, among Calpine Corporation, as borrower, certain subsidiaries of the Company named therein, as guarantors, the lenders party thereto, Goldman Sachs Credit Partners L.P., as administrative agent and collateral agent, and the other agents named therein
First Lien Notes	Collectively, the 2017 First Lien Notes, the 2019 First Lien Notes, the 2020 First Lien Notes, the 2021 First Lien Notes and the 2023 First Lien Notes
FRCC	Florida Reliability Coordinating Council
Freestone	Freestone Energy Center, a 994 MW natural gas-fired, combined-cycle power plant located near Fairfield, Texas
GE	General Electric International, Inc.
GEC	Collectively, Gilroy Energy Center, LLC, Creed and Goose Haven
Geysers Assets	Our geothermal power plant assets, including our steam extraction and gathering assets, located in northern California consisting of 15 operating power plants and one plant not in operation
GHG(s)	Greenhouse gas(es), primarily carbon dioxide (CO_2), and including methane (CH_4), nitrous oxide (N_2O), sulfur hexafluoride (SF_6), hydrofluorocarbons (HFCs) and perfluorocarbons (PFCs)

ABBREVIATION	DEFINITION
Gilroy	Calpine Gilroy Cogen, L.P.
Goose Haven	Goose Haven Energy Center, LLC
Greenfield LP	Greenfield Energy Centre LP, a 50% partnership interest between certain of our subsidiaries and a third party which operates the Greenfield Energy Centre, a 1,038 MW natural gas-fired, combined-cycle power plant in Ontario, Canada
Heat Rate(s)	A measure of the amount of fuel required to produce a unit of power
Hg	Mercury
IOUs	Investor Owned Utilities
IRC	Internal Revenue Code
ISO(s)	Independent System Operator(s)
ISO-NE	ISO New England
ISRA	Industrial Site Recovery Act
KWh	Kilowatt hour(s), a measure of power produced, purchased or sold
LIBOR	London Inter-Bank Offered Rate
Los Esteros Project Debt	Credit Agreement dated August 23, 2011, between Los Esteros Critical Energy Facility, LLC, as borrower, and the lenders named therein
LTSA(s)	Long-Term Service Agreement(s)
Mankato	Mankato Energy Center, a 375 MW natural gas-fired, combined-cycle power plant located in Mankato, Minnesota
Market Capitalization	As of any date, Calpine Corporation's then market capitalization calculated using the rolling 30-day weighted average trading price of Calpine Corporation's common stock, as defined in and 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
MISO	Midwest ISO
MRO	Midwest Reliability Organization
MW	Megawatt(s), a measure of plant capacity
MWh	Megawatt hour(s), a measure of power produced, purchased or sold
NAAQS	National Ambient Air Quality Standards
NDH	New Development Holdings, LLC, an indirect, wholly owned subsidiary

ABBREVIATION	DEFINITION
NDH Project Debt	The $1.3 billion senior secured term loan facility and the $100 million revolving credit facility issued on July 1, 2010, under the credit agreement, dated as of June 8, 2010, among NDH, as borrower, Credit Suisse AG, as administrative agent, collateral agent, issuing bank and syndication agent, Credit Suisse Securities (USA) LLC, Citigroup Global Markets Inc. and Deutsche Bank Securities Inc., as joint book-runners and joint lead arrangers, Credit Suisse AG, Citibank, N.A., and Deutsche Bank Trust Company Americas, as co-documentation agents and the lenders party thereto repaid on March 9, 2011
New Term Loan	The $360 million first lien senior secured term loan, dated June 17, 2011, among Calpine Corporation, as borrower, and the lenders party hereto, and Morgan Stanley Senior Funding, Inc., as administrative agent and Goldman Sachs Credit Partners L.P., as collateral agent
NERC	North American Electric Reliability Council
NOL(s)	Net operating loss(es)
NOx	Nitrogen oxides
NPCC	Northeast Power Coordinating Council
NYISO	New York ISO
NYMEX	New York Mercantile Exchange
NYSE	New York Stock Exchange
OCI	Other Comprehensive Income
OMEC	Otay Mesa Energy Center, LLC, an indirect, wholly owned subsidiary that owns the Otay Mesa Energy Center, a 608 MW natural gas-fired, combined-cycle power plant located in San Diego county, California
OTC	Over-the-Counter
PCF	Power Contract Financing, L.L.C.
PCF III	Power Contract Financing III, LLC
Petition Date	December 20, 2005
PG&E	Pacific Gas & Electric Company
PHI	Pepco Holdings, Inc.
PJM	Pennsylvania-New Jersey-Maryland Interconnection
Plan of Reorganization	Sixth Amended Joint Plan of Reorganization Pursuant to Chapter 11 of the Bankruptcy Code filed by the U.S. Debtors with the U.S. Bankruptcy Court on December 19, 2007, as amended, modified or supplemented through the filing of this Report
PPA(s)	Any term power purchase agreement or other contract for a physically settled sale (as distinguished from a financially settled future, option or other derivative or hedge transaction) of any power product, including power, 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 the purchaser provides the fuel required by us to generate such power and we receive a variable payment to convert the fuel into power and steam

ABBREVIATION	DEFINITION
PUCT	Public Utility Commission of Texas
PUHCA 2005	U.S. Public Utility Holding Company Act of 2005
PURPA	U.S. 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
REC(s)	Renewable energy credit(s)
Report	This Annual Report on Form 10-K for the year ended December 31, 2011, filed with the SEC on February 9, 2012
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
Risk Management Policy	Calpine's policy applicable to all employees, contractors, representatives and agents which defines the risk management framework and corporate governance structure for commodity risk, interest rate risk, currency risk and other risks
RMR Contract(s)	Reliability Must Run contract(s)
Rocky Mountain	Rocky Mountain Energy Center, LLC, formerly an indirect, wholly owned subsidiary that owned Rocky Mountain Energy Center, a 621 MW natural gas-fired, combined-cycle power plant located in Keenesburg, Colorado, which was sold on December 6, 2010
RPS	Renewable Portfolio Standards
RTO(s)	Regional Transmission Organization(s)
Russell City Project Debt	Credit Agreement dated June 24, 2011, between Russell City Energy Company, LLC, as borrower, and the lenders named therein
SEC	U.S. Securities and Exchange Commission
Second Circuit	U.S. Court of Appeals for the Second Circuit
Securities Act	U.S. Securities Act of 1933, as amended
SERC	Southeastern Electric Reliability Council
SO_2	Sulfur dioxide
South Point	South Point Energy Center, a 530 MW natural gas-fired, combined-cycle power plant located in Mohave Valley, Arizona
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

ABBREVIATION	DEFINITION
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
Steamboat	Calpine Steamboat Holdings, LLC, an indirect, wholly owned subsidiary of Calpine Corporation
Term Loan	The $1.3 billion first lien senior secured term loan, dated March 9, 2011, among Calpine Corporation, as borrower, and the lenders party hereto, and Morgan Stanley Senior Funding, Inc., as administrative agent, Goldman Sachs Credit Partners L.P., as collateral agent, Citibank, N.A., Credit Suisse Securities (USA) LLC and Deutsche Bank Securities Inc., as co-documentation agents and Goldman Sachs Bank USA as syndication agent
TRE	Texas Regional Entity
ULC I	Calpine Canada Energy Finance ULC
ULC II	Calpine Canada Energy Finance II ULC
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, which matter was jointly administered in the U.S. Bankruptcy Court under the caption *In re Calpine Corporation, et al.*, Case No. 05-60200 (BRL) and was dismissed on December 19, 2011
U.S. GAAP	Generally accepted accounting principles in the U.S.
VAR	Value-at-risk
VIE(s)	Variable interest entity(ies)
WECC	Western Electricity Coordinating Council
Whitby	Whitby Cogeneration Limited Partnership, a 50% partnership interest between certain of our subsidiaries and a third party which operates the Whitby 50 MW natural gas-fired, simple-cycle cogeneration power plant located in Ontario, Canada
York Energy Center	565 MW dual fuel, combined-cycle generation power plant (formerly known as the Delta Project) located in Peach Bottom Township, Pennsylvania, included in the Conectiv Acquisition, which achieved COD on March 2, 2011

Forward-Looking Statements

In addition to historical information, this Report contains "forward-looking statements" within the meaning of the Private Securities Litigation Reform Act of 1995, Section 27A of the Securities Act, and Section 21E of the Exchange Act. Forward-looking statements may appear throughout this report, including without limitation, the "Management's Discussion and Analysis" section. We use words such as "believe," "intend," "expect," "anticipate," "plan," "may," "will," "should," "estimate," "potential," "project" 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:

- Financial results that may be volatile and may not reflect historical trends due to, among other things, fluctuations in prices for commodities such as natural gas and power, changes in U.S. macroeconomic conditions, fluctuations in liquidity and volatility in the energy commodities markets and our ability to hedge risks;
- Regulation in the markets in which we participate and our ability to effectively respond to changes in laws and regulations or the interpretation thereof including changing market rules and evolving federal, state and regional laws and regulations including those related to the environment and derivative transactions;
- The unknown future impact on our business from the Dodd-Frank Act and the rules to be promulgated under it;
- Our ability to manage our liquidity needs and to comply with covenants under our First Lien Notes, Corporate Revolving Facility, Term Loan, New Term Loan, CCFC Notes and other existing financing obligations;
- Risks associated with the continued economic and financial conditions affecting certain countries in Europe including financial institutions located within those countries and their ability to fund their financial commitments;
- 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, variables associated with the injection of wastewater to the steam reservoir and potential regulations or other requirements related to seismicity concerns that may delay or increase the cost of developing or operating geothermal resources;
- Competition, including risks associated with marketing and selling power in the evolving energy markets;
- The expiration or early termination of our PPAs and the related results on revenues;
- Future capacity revenues may not occur at expected levels;
- Natural disasters, such as hurricanes, earthquakes and floods, acts of terrorism or cyber attacks that may impact our power plants or the markets our power plants serve and our corporate headquarters;
- Disruptions in or limitations on the transportation of natural gas, fuel oil and transmission of power;
- Our ability to manage our customer and counterparty exposure and credit risk, including our commodity positions;
- Our ability to attract, motivate and retain key employees;
- Present and possible future claims, litigation and enforcement actions; and
- Other risks identified in this Report.

Given the risks and uncertainties surrounding forward-looking statements, you should not place undue reliance on these statements. Many of these factors are beyond our ability to control or predict. Our forward-looking statements speak only as of the date of this Report. Other than as required by law, we undertake no obligation to update or revise forward-looking statements, whether as a result of new information, future events, or otherwise.

Where You Can Find Other Information

Our website is www.calpine.com. Information contained on our website is not part of this Report. Information that we furnish or file with the SEC, including our Annual Reports on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and any amendments to or exhibits included in these reports are available for download, free of charge, on our website soon after such reports are filed with or furnished with the SEC. Our SEC filings, including exhibits filed therewith, are also

available at the SEC's website at www.sec.gov. You may obtain and copy any document we furnish or 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 may 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.

PART I

Item 1. *Business*

BUSINESS AND STRATEGY

Business

We aspire to be recognized as the premier independent wholesale power producer in the U.S. We seek to achieve this objective by delivering long-term shareholder value, operational excellence, effectively executing our hedging strategy, focusing on our customer origination program and completing on schedule and on budget, our growth capital projects. We are the largest independent wholesale power company in the U.S. measured by power produced. We own and operate primarily natural gas-fired and geothermal power plants in North America and have a significant presence in major competitive wholesale power markets in California, Texas and the Mid-Atlantic region of the U.S. Since our inception in 1984, we have been a leader in environmental stewardship. We have invested in clean power generation to become a recognized leader in developing, constructing, owning and operating an environmentally responsible portfolio of power plants. Our portfolio is primarily comprised of two types of power generation technologies: natural gas-fired combustion turbines, which are primarily efficient combined-cycle plants, and renewable geothermal conventional steam turbines. We are among the world's largest owners and operators of industrial gas turbines as well as cogeneration power plants. Our Geysers Assets located in northern California represent the largest geothermal power generation portfolio in the U.S. and produced approximately 20% of all renewable energy in the state of California during 2010. We sell wholesale power, steam, capacity, renewable energy credits and ancillary services to our customers, including utilities, independent electric system operators, industrial and agricultural companies, retail power providers, municipalities and power marketers. We purchase natural gas and fuel oil as fuel for our power plants and engage in related natural gas transportation and storage transactions. We also purchase electric transmission rights to deliver power to our customers. Additionally, consistent with our Risk Management Policy, we enter into natural gas and power physical and financial contracts to hedge certain business risks and optimize our portfolio of power plants.

Our portfolio, including partnership interests, includes 93 power plants, including 2 under construction, located throughout 20 states in the U.S. and Canada, with an aggregate generation capacity of 28,155 MW and 584 MW under construction. Our generation capacity includes 77 natural gas-fired power plants, 15 geothermal plants and 1 photovoltaic solar plant. We are one of the largest consumers of natural gas in North America and in 2011 we consumed 715 Bcf (billion cubic feet) or approximately 9% of the total estimated natural gas consumed for power generation in the U.S. We believe that having scale and geographic diversity is important in our business. Scale provides us the opportunity to have meaningful regulatory input, an ability to leverage our procurement negotiations for better price, terms and conditions on our goods and services and allows us to develop and offer a wide array of products and services to our customers. Geographic diversity helps us manage price fluctuations across our different markets.

The environmental profile of our power plants reflects our commitment to environmental leadership and stewardship. We have invested the necessary capital to develop a power generation portfolio that has substantially lower air pollutant emissions compared to our competitors' power plants using other fossil fuels, such as coal. In addition, we strive to preserve our nation's valuable water and land resources. To condense steam, our combined-cycle power plants 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. Since our plants are modern and efficient and utilize clean burning natural gas, we do not require large areas of land for our power plants nor do we require large specialized landfills for the disposal of coal ash or nuclear plant waste. We believe that we will be less adversely impacted by cap-and-trade limits, carbon taxes or required environmental upgrades as a result of future potential regulation or legislation addressing GHG, other air pollutant emissions, as well as water use or emissions, than compared to our competitors who use other fossil fuels or older, less efficient technologies.

We remain focused on creating long-term shareholder value through making effective capital allocation decisions, increasing our earnings and generating cash flow sufficient to maintain adequate levels of liquidity in order to service our debt, meet our collateral needs and fund our operations and growth. We will continue to pursue opportunities to improve our fleet performance and reduce operating costs. In order to manage and optimize our various physical assets and contractual obligations, we will continue to execute commodity hedging agreements within the guidelines of our Risk Management Policy.

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 and capacity from our cogeneration power plants, combustion turbine power plants and geothermal power plants, as well as the sale of renewable energy credits, or RECs, from our geothermal and solar power plants, provide a stable source of revenue. 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.

Our principal offices are located in Houston, Texas with regional offices in Dublin, California and Wilmington, Delaware, an engineering, construction and maintenance services office in Pasadena, Texas and government affairs offices in Washington D.C., Sacramento, California and Austin, Texas. We operate our business through a variety of divisions, subsidiaries and affiliates.

Strategy

Our goal is to be recognized as the premier independent power company in the U.S. as measured by our employees, shareholders, customers and regulators as well as the communities in which our facilities are located. We seek to achieve sustainable growth through financially disciplined power plant development, construction, acquisition, operation and ownership. Our strategy to achieve this is reflected in the five major initiatives described below:

1. *Premier Operating Company* — Our objective is to be the "best-in-class" in regards to certain operational performance metrics, such as safety, availability, reliability, efficiency and cost management.
    - Throughout 2011, our plant operating personnel achieved the first quartile performance for employee lost time incident rate for fossil fuel electric power generation companies with 1,000 or more employees.
    - We produced over 94 billion KWh in 2011.
    - Our entire fleet achieved a forced outage factor of 2.5%.
    - We achieved 98.4% fleet-wide starting reliability in 2011.
    - During 2011, our Turbine Maintenance Group completed 16 major inspections and 15 hot gas path inspections.
    - For the past eleven consecutive years, our Geysers Assets have reliably generated approximately 6 million MWh per year and, in 2011, achieved an exceptional availability factor of approximately 98%.
2. *Focus on Enhancing Shareholder Value* — We continue to make significant progress to maintain financially disciplined growth, to enhance shareholder value through our capital allocation and share repurchases and to set the foundation for continued growth and success. Given our strong cash flow from operations, we are committed to remaining financially disciplined in our capital allocation decisions. The year ended December 31, 2011 was marked by the following accomplishments:
    - Our total shareholder return for 2011 was 22.4% (measured by the year over year change in our stock price).
    - On August 23, 2011, we announced that our Board of Directors had authorized the repurchase of up to $300 million in shares of our common stock. Through the filing of this Report, a total of 8,524,576 shares of our outstanding common stock have been repurchased under this program for approximately $124 million at an average price paid of $14.60 per share.
    - We issued our 2023 First Lien Notes, terminated our First Lien Credit Facility and extended our corporate debt maturities. Together, these changes eliminated the more restrictive of our debt covenants, resulting in increased operational, strategic and financial flexibility in managing our capital resources including the flexibility to reinvest more earnings for organic growth, issue and/or buyback shares of our common stock and incur additional debt, if needed, for acquisitions or development projects. Additionally, we achieved attractive yields and a maturity schedule stretching from 2017 to 2023 with no more than $2.0 billion of corporate debt maturing in any given year.
    - We have further continued to reduce our overall cost of debt and simplify our capital structure by refinancing subsidiary level debt with corporate level term loans eliminating the need for subsidiary level reporting and the potential for cash to be temporarily trapped at the subsidiary level. On March 9, 2011, we closed on the $1.3 billion Term Loan and used the net proceeds received, together with operating cash on hand, to fully retire the approximately $1.3 billion NDH Project Debt in accordance with its repayment terms. On June 17, 2011, we repaid approximately $340 million of project debt with the proceeds received from $360 million in borrowings under the New Term Loan.

- On June 24, 2011, we closed on the approximately $845 million Russell City Project Debt to fund the construction of Russell City Energy Center and on August 23, 2011, we closed on the $373 million Los Esteros Project Debt to fund the upgrade of our Los Esteros Critical Energy Facility.
- During the fourth quarter of 2011, the U.S. Bankruptcy Court issued an order dismissing the Chapter 11 cases that remained open against the U.S. Debtors; thus, all matters related to our voluntary petitions for relief under Chapter 11 of the Bankruptcy Code filed in 2005 and 2006 are resolved and closed.

3. *Leader in Environmental Responsibility* — Our focus is to utilize our modern, efficient fleet to deliver low environmental impact energy solutions relative to other fossil fuel generation as part of our commitment to environmental stewardship. Some examples that demonstrate this commitment include:
   - We continue to actively participate in legislative and regulatory processes addressing environmental concerns and support legislative and regulatory action to address best available control technology, cross-state air pollution, once-through cooling water systems, climate change, GHG and other air emissions from fossil fuel generation. We intend to leverage our baseload geothermal expertise to grow our renewable energy portfolio.
   - Our strong and continuing commitment to environmental responsibility and leadership is exemplified by our development of the Russell City Energy Center which is under construction and intended to become the first power plant in the U.S. with a federal limit on GHG emissions. Russell City Energy Center will be designed to operate in a way that produces 25% fewer GHG emissions than the CPUC standard. The power plant will use 100% reclaimed water from the City of Hayward's Water Pollution Control Facility for cooling and boiler makeup, which will prevent nearly four million gallons of wastewater per day from being discharged into the San Francisco Bay. We initiated and agreed to accept the GHG permit limit and designed the plant to benefit local water resources.
4. *Focus on Leveraging our Three Scale Regions* — Our goal is to continue to grow our presence in core markets with an emphasis on expansions or upgrades of existing power plants. We intend to take advantage of favorable opportunities to continue to design, develop, acquire, construct and operate the next generation of highly efficient, operationally flexible and environmentally responsible power plants where such investment meets our rigorous financial hurdles, particularly if power contracts and financing are available and attractive returns are expected. Likewise, we will actively seek divestiture opportunities on our non-core assets if those opportunities meet our financial expectations. In addition, we believe that upgrades and expansions to our current assets offer proven and financially disciplined opportunities to improve our operations, capacity and efficiencies. Our significant projects under construction, growth initiatives and upgrades are discussed below.

   PJM:
   - *York Energy Center* — Our York Energy Center, a 565 MW dual fuel, combined-cycle power plant achieved COD on March 2, 2011, and began selling power under a six-year PPA with a third party which commenced on June 1, 2011.
   - Given our view of the potential need for new generation in the PJM region, driven both by market growth and the expected impacts of environmental regulations on older, less efficient generation within the region, we view the PJM region as a market with an attractive growth profile. In order to capitalize on this outlook, we are actively pursuing a set of development options, including projects at:
     - *Garrison (Delaware)*: Actively permitting 618 MW of new combined-cycle capacity at a development site secured by a lease option with the City of Dover. PJM's system impact study for the first phase (309 MW) and the feasibility study for the second phase (309 MW) have been completed. Both studies are being reviewed internally. Environmental permitting, site development planning and development engineering are underway.
     - *Edge Moor (Delaware)*: A nominal 300 MW combined-cycle development project located at our Edge Moor facility which will leverage existing infrastructure. PJM is currently conducting a system impact study which will provide a detailed report on the project's interconnection costs.

   West:
   - *Russell City Energy Center* — The Russell City Energy Center is under construction and continues to move forward with expected COD in 2013. Upon completion, this project will bring on line approximately 429 MW of net interest baseload capacity (464 MW with peaking capacity) representing our 75% share. We are in possession of all required approvals and permits, and we closed on construction financing on June 24, 2011. Upon completion, the Russell City Energy Center is contracted to deliver its full output to PG&E under a ten-year PPA.

- *Los Esteros* — During 2009, we and PG&E negotiated a new PPA to replace the existing California Department of Water Resources contract and facilitate the upgrade of our Los Esteros Critical Energy Facility from a 188 MW simple-cycle generation power plant to a 308 MW combined-cycle generation power plant, which will also increase the efficiency and environmental performance of the power plant by lowering the Heat Rate. The ten-year PPA and related agreements with PG&E have received all of the necessary approvals and licenses, which are now effective. The California Energy Commission has renewed our license and emission limits, which is final. The Bay Area Air Quality Management District issued its renewal of the Authority to Construct. We began construction in the second quarter of 2011 and obtained construction financing on August 23, 2011. We expect COD in 2013.
- *Geysers Assets Expansion* — We continue to look to expand our production from our Geysers Assets. Beginning in the fourth quarter of 2009, we conducted an exploratory drilling program, which effectively proved the commercial viability of the steam field in the northern part of our Geysers Assets. We have received Conditional Use Permits from Sonoma County and are pursuing the additional required permitting. We are pursuing commercial arrangements which will need to be in place prior to commencing expansion activities. We continue to believe our northern Geysers Assets have potential for development. In the meantime, we have connected certain test wells to our existing power plants to capture incremental production from those wells, while continuing with the permitting process, baseline engineering work and sales efforts for an expansion.

ERCOT:

- *Channel and Deer Park Expansions* — We continue to evaluate the ERCOT market for expansion opportunities based on tightening reserve margins and potential impact of EPA regulations on generation in Texas. At both our Deer Park and Channel Energy Centers, we have the ability to install an additional combustion turbine generator and connect to the existing steam turbine generator to expand the capacity of these facilities and to improve the overall efficiency. In September 2011, we filed an air permit application with the Texas Commission on Environmental Quality ("TCEQ") and the EPA to expand the Deer Park Energy Center by approximately 275 MW. In November 2011, we filed similar permits with the TCEQ and the EPA to expand the Channel Energy Center by approximately 275 MW.

All Markets:

- *Turbine Upgrades* — We continue to move forward with our turbine upgrade program. Through December 31, 2011, we have completed the upgrade of ten Siemens and five GE turbines and have agreed to upgrade approximately six additional Siemens and GE turbines (and may upgrade additional turbines in the future). Our turbine upgrade program is expected to increase our generation capacity in total by approximately 275 MW. This upgrade program began in the fourth quarter of 2009 and is scheduled through 2014. The upgraded turbines have been operating with Heat Rates consistent with expectations.

5. *Customer-Oriented Origination Business* — We continue to focus on providing products and services that are beneficial to our customers. A summary of certain significant contracts entered into or approved in 2011 is as follows:
   - We have entered into a new ten-year PPA with Entergy Texas to provide 485 MW of power generated by our Carville Energy Center which will commence in June 2012.
   - We have entered into a new tolling agreement with Southern California Edison to provide 750 MW of power generated by our Pastoria Energy Center which will commence in 2013, and we executed a new resource adequacy contract with the same counterparty for 715 MW from our Pastoria Energy Center which will commence in 2014.
   - We have entered into a PPA with Tampa Electric Company for the full output of our Auburndale Peaking Energy Center which commenced in November 2011 and will run through December 2016.

THE MARKET FOR POWER

Our Power Markets and Market Fundamentals

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 of approximately $373 billion in power sales in 2011 according to the EIA. Historically, vertically integrated power utilities with monopolies over franchised territories dominated the power generation industry in the U.S. Over the last 25 years, 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 power. Although different regions of the country have very different models and rules for competition, the markets in which we operate have some form of wholesale market competition. California (included in our West segment), Texas and the Mid-Atlantic (included in our North segment), which are three of our largest markets, have emerged as among the most competitive wholesale power markets in the U.S. We also operate, to a lesser extent, in the competitive ISO-NE, NYISO and MISO markets. We produce several products for sale to our customers.

- First, we produce power for sale to utilities, municipalities, retail power providers, independent electric system operators, large end-use industrial or agricultural customers or power marketers. Our power sales occur in several different product categories including baseload (around the clock generation), intermediate (generation typically more expensive than baseload and utilized during higher demand periods to meet shifting demand needs), and peaking capacity (most expensive variable cost and utilized during the highest demand periods), for which the latter is provided by some of our stand alone peaker power plants/units and from our combined-cycle power plants by using technologies such as steam injection or duct firing additional burners in the heat recovery steam generators. Many of our units have operated more frequently as baseload units at times when low natural gas prices have driven their production costs below those of some competing coal-fired units.
- Second, our cogeneration power plants produce steam for sale to customers for use in industrial or heating, ventilation and air conditioning operations.
- Third, we provide capacity for sale to retail power providers. In various markets, retail power providers are required to demonstrate adequate resources to meet their power sales commitments. To meet this obligation, they procure a market product known as capacity. Most electricity market administrators have acknowledged that an energy only market does 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, the Mid-Atlantic and some mid-west regional markets to address this issue. California has a bilateral capacity program. Texas does not presently have a capacity market.
- Fourth, we provide ancillary service products to wholesale power markets. These products include the right for the purchaser to call on our generation to provide flexibility to the market and support operation of the electric grid. As an example, we are sometimes paid to reserve a portion of some capacity at some of our power plants that could be deployed quickly should there be an unexpected increase in load or to assure reliability due to fluctuations in the supply of power from variable renewable resources such as wind and solar generation.
- Fifth, we sell RECs from our Geysers Assets in northern California, as well as from our small solar power plant in New Jersey. 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. New Jersey has a solar specific RPS which enables us to sell RECs from our Vineland Solar Energy Center.

In addition to the five products above, we are buyers and sellers of environmental allowances and credits, including those under RGGI, the federal Acid Rain and Clean Air Interstate Rule programs and emission reduction credits under the federal Nonattainment New Source Review program. We also participate in CO_2 emissions credit markets related to California's AB 32 GHG reduction program.

Although all of the products mentioned above contribute to our financial performance and are the primary components of our Commodity Margin, the most important is our sale of wholesale power. We utilize long-term customer contracts for our power and steam sales where possible. 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.

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 market Spark Spread is positive. Assuming economic behavior by market participants, generating units generally are dispatched in order of their variable costs, with lower cost units 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 variable operating costs of the marginal generator, which is the last unit to be dispatched in order to meet demand. The market factors that most significantly impact our operations are reserve margins, the price and supply of natural gas and competing fuels such as coal and oil, weather patterns and natural events, our operating Heat Rate and Availability, and regulatory and environmental pressures as further discussed below.

Reserve Margins

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 under normal weather conditions. Holding other factors constant, lower reserve margins typically lead to higher power prices because the less efficient capacity in the region is needed more often to satisfy power demand. Markets with tight demand and supply conditions often display price spikes and improved bilateral contracting opportunities. Typically, the market price impact of reserve margins, as well as other supply/demand factors, is reflected in the Market Heat Rate calculated as the local market power price divided by the local natural gas price.

During the last decade, the supply and demand fundamentals in many regional markets were negatively impacted by the combination of new generation coming on line and a general decline in weather normalized load growth rates due to the economic recession. Although uncertainty exists and there are key regional differences at a macro level, continued economic recovery and thus, corresponding load recovery, with the lack of broad new power plant investments in our key markets should lead to lower reserve margins and higher market Heat Rates. Reserve margins by NERC regional assessment area for each of our segments are listed below:

	2011[(1)]
West:	
WECC	35.1%
Texas:	
TRE	17.5%
North:	
NPCC	28.1%
MISO	24.0%
PJM	32.3%
Southeast:	
SERC	28.4%
SPP	27.9%
FRCC	24.7%

(1) Data source is EIA

The Price and Supply of Natural Gas

Our fuel requirements are predominantly met with natural gas. We have approximately 725 MW of capacity from our Geysers Assets and our expectation is that the steam reservoir at our Geysers Assets will be able to supply economic quantities of steam for the foreseeable future as our steam flow decline rates have become very small over the past several years. We also have approximately 371 MW of capacity from power plants where we purchase fuel oil to meet these generation requirements if required, but do not expect fuel oil requirements to be material to our portfolio of power plant assets. Additionally, we have 4 MW of capacity from solar power generation technology with no fuel requirement.

We procure natural gas from multiple suppliers and transportation sources. Although availability is generally not an issue, localized shortages (especially in extreme weather conditions), transportation availability and supplier financial stability issues can and do occur.

Lower gas prices over the past three years have had a significant impact on power markets. Beginning in 2009, there was a significant decrease in NYMEX Henry Hub natural gas prices from a range of $6/MMBtu — $13/MMBtu during 2008 to an average natural gas price of $4.16, $4.38, and $4.03 during 2009, 2010 and 2011, respectively. Natural gas prices in some parts of the country for parts of 2009, 2010 and 2011 were low enough that modern combined-cycle natural gas-fired generation became less expensive on a marginal basis than coal-fired generation. The result was that natural gas displaced coal as a less expensive generation resource resulting in what the industry describes as coal-to-gas switching.

Although some of this lower pricing dynamic can be attributed to the economic recession, the availability of non-conventional natural gas supplies, in particular shale natural gas, has also kept natural gas prices low. Access to significant deposits of shale natural gas has altered the natural gas supply landscape in the U.S. and could have a longer-term and profound impact on both the outright price of natural gas and the historical regional natural gas price relationships (basis differentials). The U.S. Department of Energy estimates that shale natural gas production has the potential of 3 trillion to 4 trillion cubic feet per year and may be sustainable for decades with enough natural gas to supply the U.S. for the next 90 years. Accordingly, there is an emerging view that lower priced natural gas will be available for the medium to long-term future.

The relative price of natural gas can have varying results on our Commodity Margin and liquidity. The impact of changes in natural gas prices differs according to the time horizon and regional market conditions and depends on our hedge levels and other factors discussed below.

Much of our generating capacity is located in California (included in our West segment), Texas and the Mid-Atlantic (included in our North segment) where natural gas-fired units set power prices during most hours or most "peak" hours. "Peak" hours are generally considered between the hours of 7:00 a.m. and 11:00 p.m., with the remaining hours considered "off-peak." In California and Texas, natural gas-fired units set prices during most hours, although incremental renewable generation and coal-to-gas switching have moderated this dynamic somewhat in off-peak hours over the last year. In the Mid-Atlantic, natural gas-fired units set prices during most peak hours. Outside of our California, Texas and Mid-Atlantic markets, coal-fired power plants tend to set power prices more often.

When natural gas is the price-setting fuel, which is often the case in Texas, California and the Mid-Atlantic, increases in natural gas prices may increase our unhedged Commodity Margin because our combined-cycle power plants in those markets are more fuel-efficient than conventional natural gas-fired technologies and peaker power plants. Conversely, decreases in natural gas prices tend to decrease our unhedged Commodity Margin. In these instances, our cost of production advantage relative to less efficient natural gas-fired generation is diminished on an absolute basis.

Natural gas-fired combined-cycle units in many markets are now frequently cheaper to dispatch than coal-fired power plants. When coal-fired electricity production costs exceed natural gas-fired production costs, coal-fired units tend to set power prices. In these hours, lower natural gas prices tend to increase our Commodity Margin, since our production costs fall while power prices remain constant (depending on our hedge levels and holding other factors constant).

Where we operate under long-term contracts, changes in natural gas prices can have a neutral impact on us in the short-term. This tends to be the case where we have entered into tolling agreements under which the customer provides the natural gas and 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. During periods of high or volatile natural gas prices, we could be required to post additional cash collateral or letters of credit.

Over the long-term, we expect lower natural gas prices to increase coal-to-gas switching, thus enhancing the competitiveness of our modern natural gas fleet and making investments in coal less attractive. Despite these short-term dynamics, over the long run, we expect lower natural gas prices to enhance the competitiveness of our modern, natural gas-fired fleet by making investment in other technologies such as coal, nuclear, or renewables less economic.

Weather Patterns and Natural Events

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

Operating Heat Rate and Availability

Our fleet is modern and more efficient than the average generation fleet; accordingly, we run more and earn incremental margin in markets where less efficient natural gas units frequently set the power price. In such cases, our unhedged Commodity Margin is positively correlated with how much more efficient our fleet is than our competitors' fleets and with higher natural gas prices. Efficient operation of our fleet creates the opportunity to capture Commodity Margin. However, unplanned outages during periods when Commodity Margin is positive can result in a loss of that opportunity. We measure our fleet performance based on our operating Heat Rate and availability factors. The higher our availability factor, the better positioned we are to capture Commodity Margin. The lower our operating Heat Rate compared to the Market Heat Rate, the more favorable the impact on our Commodity Margin.

Regulatory and Environmental Pressures

We believe that, on a net basis, we will be favorably impacted by regulatory factors including those described below, given the characteristics of our power plant portfolio:

- An increase in power generated from renewable sources could lead to an increased need for flexible power that many of our power plants provide to protect the reliability of the grid; however, risks also exist that renewables have the ability to lower overall wholesale prices which could negatively impact us. Significant economic and reliability concerns for renewable generation have slowed their growth in 2011 and 2010 compared to 2009, but we expect that renewable market penetration will continue to be assisted by state-level renewable portfolio standards.

- Environmental pressures continue to increase for coal-fired power generation as state and federal agencies enact rules to reduce air emissions of certain pollutants such as SO_2, NO_X, GHG, Hg and acid gases, restrict the use of once-through cooling, and provide for stricter standards for managing coal combustion residuals. Some of the regions in which we operate include older, less efficient fossil-fuel power plants that emit much higher amounts of GHG, SO_2, NO_X, Hg and acid gases, which we anticipate will be negatively impacted by future air emissions, water and waste regulations and legislation. The estimated capacity for fossil-fueled plants which are older than 50 years by NERC region are as follows:

West:		
WECC	7,307	MW
Texas:		
TRE	3,562	MW
North:		
NPCC	6,381	MW
MRO	4,597	MW
RFC	27,612	MW
Southeast:		
SERC	28,051	MW
SPP	4,781	MW
FRCC	1,211	MW
Total	83,502	MW

- Utilities are increasingly focused on demand side management – managing the level and timing of power usage through load curtailment, dispatching generators located at commercial or industrial sites, and "smart grid" technologies that may improve the efficiencies, dispatch usage and reliability of electric grids. Scrutiny of demand side resources has increased in recent months as system operators evaluate their reliability (especially at high levels of penetration) and environmental authorities grapple with the implications of relying on smaller, less environmentally efficient generation sources during periods of peak demand when air quality is already challenged.
- Environmental permitting requirements for new power plants and transmission lines are becoming increasingly onerous.

We believe these trends are positive for our fleet. For a discussion of federal, state and regional legislative and regulatory initiatives and how they might affect us, see "— Governmental and Regulatory Matters."

It is very difficult to predict the continued evolution of our markets due to the uncertainty of the following:

- number of market participants;
- amount of power 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, which could be impacted by the efficiency of generation technology and fluctuations in fuel supply or interruptions in natural gas transportation;
- relative ease or difficulty of developing, permitting and constructing new power plants;
- availability and cost of power transmission;
- potential growth of demand side management;
- creditworthiness and other risks associated with counterparties;
- bidding behavior of market participants;
- regulatory and ISO guidelines and rules;
- structure of commercial products; and
- ability to optimize the market's mix of alternative sources of power such as renewable and hydroelectric power.

Competition

Wholesale power generation is a capital-intensive, commodity-driven business with numerous industry participants. We compete against other independent power producers, power marketers and trading companies, including those owned by 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. and Canada. In addition, in some markets, we compete against some of our customers.

In less regulated markets, such as California, Texas and the Mid-Atlantic, our natural gas-fired power plants compete directly with all other sources of power. The EIA estimates that in 2011, 24% of the power generated in the U.S. was fueled by natural gas and that approximately 62% of power generated in the U.S. was produced by coal and nuclear facilities, which generated approximately 43% and 19%, respectively. The EIA estimates that the remaining 14% of power generated in the U.S. was fueled by hydroelectric, fuel oil and other energy sources. 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. The federal government is expected to continue to take further action on many air pollutant emissions such as NOx, SO_2, Hg and acid gases as well as on once-through cooling and coal ash disposal. Although we cannot predict the ultimate effect any future environmental legislation or regulations will have on our business, as a clean energy provider, we believe that we are well positioned for almost any increase in environmental rule stringency. We are actively participating in these debates at the federal, regional and state levels. For a further discussion of the environmental and other governmental regulations that affect us, see "— Governmental and Regulatory Matters."

As environmental regulations evolve, the proportion of power generated by natural gas and other low emissions resources is expected to increase because older coal-fired power plants will likely have to install costly emission control devices, limit their operations or be retired. Meanwhile, the federal government and many states are considering or have already mandated that certain percentages of power delivered to end users in their jurisdictions be produced from renewable resources, such as geothermal, wind and solar energy.

Competition from other sources of power, such as nuclear energy and renewables, is expected to increase in the future, but at a lower rate than had been expected in 2008 or 2009. The nuclear incident in March 2011 at the Fukushima Daiichi nuclear power plant introduced substantial uncertainties around new nuclear power plant development in the U.S. In addition, the combination of emerging air emissions regulations, federal and state financial incentives and RPS requirements for renewables and their impact of expected increased investment in cleaner sources of generation will be somewhat counteracted by a lower natural gas price environment, which, should it persist, makes new investment in these types of power generation generally uneconomical. Thus, it is doubtful that generation from new nuclear power plants and renewable sources will be available in the quantities needed to meet future energy demand. Beyond economic issues, there are concerns over the reliability and adequacy of transmission infrastructure to transmit certain renewable generation from its source to where it is needed. Consequently, longer-term, natural gas is likely still needed as baseload and "back-up" generation.

We believe our ability to compete will be driven by the extent to which we are able to accomplish the following:

- maintain excellence in operations;
- achieve and maintain a lower cost of production, primarily by maintaining unit availability and efficiency;
- benefit from future environmental regulation and legislation;
- accurately assess and effectively manage our risks; and
- provide reliable service to our customers.

MARKETING, HEDGING AND OPTIMIZATION ACTIVITIES

Our hedging strategy and commercial efforts attempt to maximize our risk adjusted Commodity Margin by leveraging our knowledge, experience and fundamental views on natural gas and power. We actively manage our commodity price risk with a variety of tools, including PPAs and other long-term contracts for the sale of power and steam. We also pursue other long-term sales opportunities, as well as shorter term market transactions, including bilateral originated sales contracts, and purchase and sale of exchange-traded instruments. We actively monitor 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 capacity and geographic locational risk in both power and natural gas, REC and emission credit pricing. The relative quantity of our products hedged or sold under longer term contracts is determined by the availability of forward product sales opportunities and our view of the attractiveness of the pricing available for forward sales or through hedging. It is our strategy to seek stronger bilateral relationships under long-term contracts with load serving entities that can benefit us and our customers.

The majority of our marketing, hedging and optimization activities are related to risk exposures that arise from our ownership and operation of power plants. We are one of the largest consumers of natural gas in the U.S. having consumed approximately 715 Bcf during 2011. Most of the power generated by our power plants is sold 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. We actively seek to manage and limit the commodity risks of our portfolio, utilizing multiple strategies of buying and selling power, natural gas and Heat Rate contracts to manage our Spark Spread and products that manage geographic price differences (basis differential). We have approximately 371 MW of capacity from power plants that have flexibility as to fuel source where we purchase fuel oil to meet these generation requirements if required; however, we have not currently entered into any hedging or optimization transactions for our fuel oil requirements as we do not expect fuel oil requirements to be material to us, but may elect to do so in the future.

Along with our portfolio of hedging transactions, we enter into power and natural gas positions that often act as economic hedges to our asset portfolio, but do not qualify for or we elect not to designate as hedges under hedge accounting guidelines, such as commodity options transactions and instruments that settle on power price to natural gas price relationships (Heat Rate swaps and options) or instruments that settle on power price relationships between delivery points. 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. We use derivative instruments, which include physical commodity contracts and financial commodity instruments such as OTC and exchange traded swaps, futures, options, forward agreements and instruments that settle on the power price to natural gas price relationships (Heat Rate swaps and options) for the purchase and sale of power, natural gas, and emission allowances to manage commodity price risk and to maximize the risk-adjusted returns from our power and natural gas assets. We conduct these hedging and optimization activities within a structured risk management framework based on controls, policies and procedures. We monitor these activities through active and ongoing management and oversight, defined roles and responsibilities, and daily risk measurement and reporting. Additionally, we seek to manage the associated risks through diversification, by controlling position sizes, by using portfolio position limits, and by entering into offsetting positions that lock in a margin. We also are exposed 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 or we do not elect either hedge accounting or the normal purchase normal sale exemption are recognized currently in earnings within operating revenues in the case of power transactions, and within fuel and purchased energy expense, in the case of natural gas transactions. Our future hedged status, and marketing and optimization activities are subject to change as determined by our commercial operations group, Chief Risk Officer, Risk Management Committee of senior management and Board of Directors.

We have economically hedged a portion of our expected generation and natural gas portfolio mostly through power and natural gas forward physical and financial transactions; however, we remain susceptible to significant price movements for 2012 and beyond. 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 use a combination of PPAs and other hedging instruments to manage our variability in future cash flows. At December 31, 2011, the maximum length of time that our PPAs extended was approximately 23 years into the future and the maximum length of time over which we were hedging using commodity and interest rate derivative instruments was 3 and 12 years, respectively.

We have historically used interest rate swaps to adjust the mix between our fixed and variable rate debt. To the extent eligible, our interest rate swaps have been designated as cash flow hedges, and changes in fair value are recorded in OCI to the extent they are effective with gains and losses reclassified into earnings in the same period during which the hedged forecasted transaction affects earnings. The reclassification of unrealized losses from AOCI into income and the changes in fair value and settlements subsequent to the reclassification date of the interest rate swaps formerly hedging our First Lien Credit Facility is presented separately from interest expense as loss on interest rate derivatives on our Consolidated Statements of Operations. On January 14, 2011, we repaid the remaining balance under the First Lien Credit Facility term loans with the proceeds received from the issuance of the 2023 First Lien Notes and the unrealized losses related to these interest rate swaps of approximately $91 million previously recorded in AOCI were reclassified out of AOCI and into income as additional loss on interest rate derivatives during 2011. In addition, we reclassified approximately $17 million in unrealized losses in AOCI to loss on interest rate derivatives during 2011 resulting from the repayment of project debt in June 2011. During 2010, we reclassified approximately $206 million out of AOCI and into income as additional loss on interest rate derivatives related to interest rate swaps formerly hedging our First Lien Credit Facility term loans.

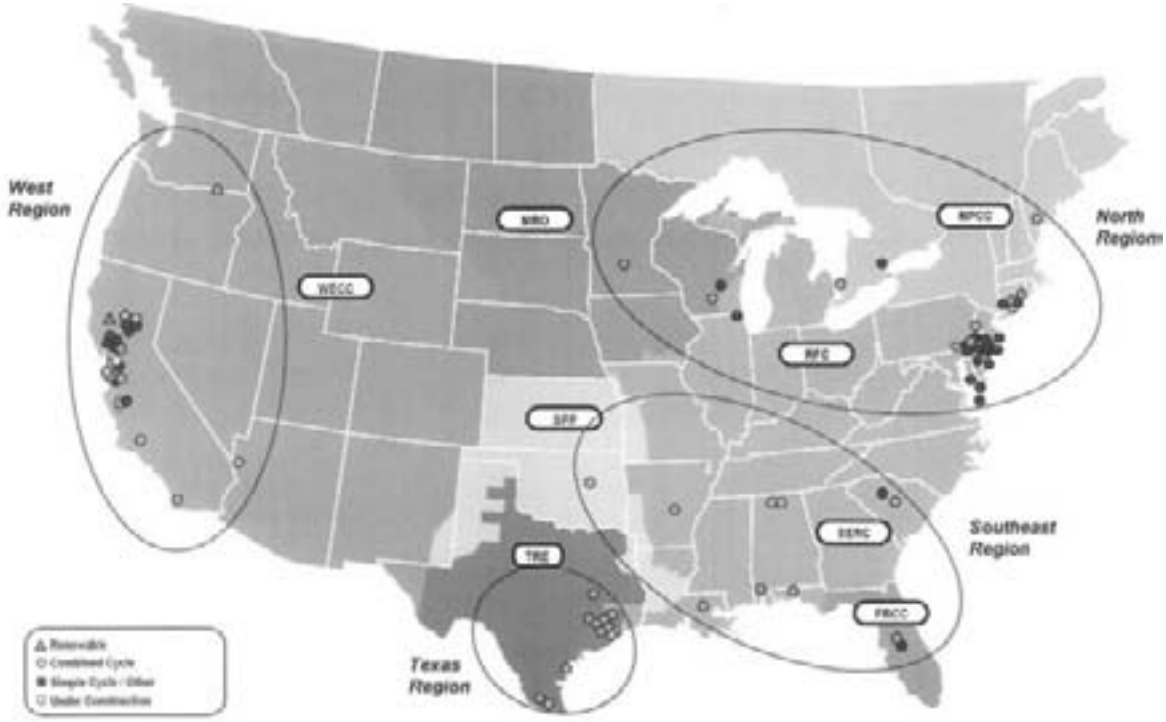
We have VAR limits that govern the overall risk of our portfolio of power plants, energy contracts, financial hedging transactions and other contracts. Our VAR limits, transaction approval limits and other risk related controls, are dictated by our Risk Management Policy which is approved by our Board 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 Policy is primarily intended to provide us with a degree of protection from significant downside energy commodity price exposure to our cash flows.

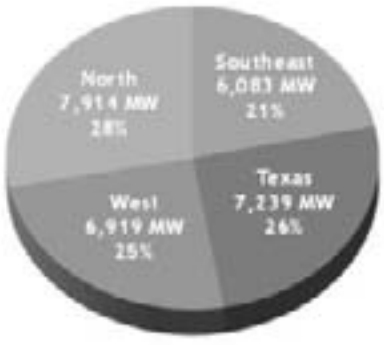
Seasonality and weather can have a significant impact on our results of operations and are also considered in our hedging and optimization activities. Most of our power plants are located in regional power markets where the greatest demand for power occurs during the summer months, which is our fiscal 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 in order to protect and enhance our Commodity Margin accordingly.

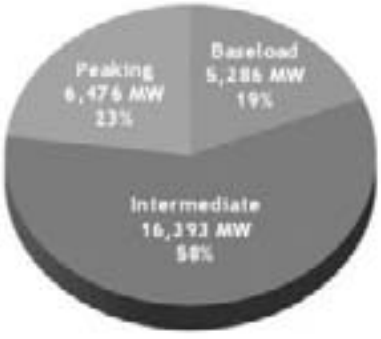
SEGMENT AND SIGNIFICANT CUSTOMER INFORMATION

See Note 16 of the Notes to Consolidated Financial Statements for a discussion of financial information by reportable segment and sales in excess of 10% of our annual consolidated revenues to one of our customers.

DESCRIPTION OF OUR POWER PLANTS







Power Plants in Operation at December 31, 2011

We own 93 power plants, including 2 under construction, with an aggregate generation capacity of approximately 28,155 MW and 584 MW under construction.

Natural Gas-Fired Fleet

Our natural gas-fired power plants primarily utilize two types of design: 3,515 MW of simple-cycle combustion turbines and 23,043 MW of combined-cycle combustion turbines and a small portion from natural gas-fired steam turbines. Simple-cycle combustion turbines burn natural gas or oil to spin a single electric generator to produce power. A combined-cycle unit combusts fuel like a simple-cycle combustion turbine and the exhaust heat is captured by a boiler to 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 2011 for the power plants we operate was 7,412 Btu/KWh which results in a power conversion efficiency of approximately 46%. The power conversion efficiency is a measure of how efficiently a fossil fuel power plant converts thermal energy to electrical energy. Our "all in" Steam Adjusted Heat Rate includes all fuel required to dispatch our power 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 an average power conversion efficiency of approximately 50%. Additionally, we also sell steam from our combined heat and power plants, which improves our power conversion efficiency in steady state operations from these power plants to an average of approximately 53%. Due to our modern combustion turbine fleet, our power conversion efficiency is significantly better than that of older technology natural gas-fired power plants and coal-fired power 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, another 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 a weighted average age, based upon MW capacities in operation, of approximately twelve years. Taken as a portfolio, our natural gas power plants are among the most efficient in converting natural gas to power and emit far fewer pollutants than most typical utility fleets. The age, scale, efficiency and cleanliness of our power plants is a unique profile in the independent power sector.

The majority of the combustion turbines in our fleet are one of four technologies: GE 7FA, GE LM6000, Siemens 501FD or Siemens V84.2 turbines. 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 or number of starts, we perform the maintenance that is required for that unit at that stage in its life cycle. Our large fleet of similar technologies has enabled us to build significant technical and engineering experience with these units. We leverage this experience by performing much of our major maintenance ourselves with our Turbine Maintenance Group subsidiary.

Geothermal Fleet

Our Geysers Assets are a 725 MW fleet of 15 operating 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. The steam is produced below the Earth's surface from reservoirs of hot water, both naturally occurring and injected. The steam is piped directly from the underground production wells to the power plants and used to spin turbines to make power. For the past eleven consecutive years, our Geysers Assets have continued to generate approximately 6 million MWh per year. Unlike other renewable resources such as wind or sunlight, which depend on intermittent sources to generate power, making them less reliable, geothermal power provides a consistent source of energy as evidenced by our Geysers Assets' availability record of approximately 98% in 2011.

We inject water back into the steam reservoir, which extends the useful life of the resource and helps to maintain the output of our Geysers Assets. The water we inject comes from the condensate associated with the steam extracted to generate power, wells and creeks, as well as water purchase agreements for reclaimed wastewater. We receive and inject an average of approximately 18 million gallons of reclaimed wastewater per day into the geothermal steam reservoir at The Geysers where the water is naturally heated by the Earth, creating additional steam to fuel our Geysers Assets. Approximately 14 million gallons per day is received from the Santa Rosa Geysers Recharge Project, developed by us and the City of Santa Rosa, which was previously being discharged into the Russian River and we receive, on average, approximately 4 million gallons a day from The Lake County Recharge Project from Lake County. As a result, MWh production has been approximately flat. We expect that, as a result of the water injection program, the reservoir at our Geysers Assets will be able to supply economic quantities of steam for the foreseeable future.

We periodically review our geothermal studies to help us assess the economic life of our geothermal reserves. Our most recent geothermal reserve study was conducted in 2011. Our evaluation of our geothermal reserves, including our review of any applicable independent studies conducted, indicates that our Geysers Assets should continue to supply sufficient steam to generate positive cash flows at least through 2068. In reaching this conclusion, our evaluation, consistent with the due diligence study of 2011, 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 lease the geothermal steam fields from which we extract steam for our Geysers Assets. We have leasehold mineral interests in 110 leases comprising approximately 29,019 acres of federal, state and private geothermal resource lands in The Geysers region of northern California. Our leases cover one contiguous area of property that comprises approximately 45 square miles in the northwest corner of Sonoma County and southeast corner of Lake County. The approximate breakout by volume of steam removed under the above leases for the year ended 2011 is:

- 29% related to leases with the federal government via the Office of Natural Resources Revenue (formerly, the Minerals Management Service),
- 27% 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 our 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 our 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 our 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 40 geothermal leases comprising approximately 43,840 acres of federal geothermal resource lands in the Glass Mountain area in northern California, which is separate from The Geysers region. Four test production wells were drilled prior to our acquisition of these leases and we have drilled one test well since their acquisition, which produced commercial quantities of steam during flow tests. However, the properties subject to these leases have not been developed and there can be no assurance that these leases will ultimately be developed. We are currently involved in litigation concerning our Glass Mountain leases. See Note 15 of the Notes to Consolidated Financial Statements for a description of litigation relating to our Glass Mountain area leases.

Other Power Generation Technologies

Across the fleet, we also have a variety of older, less efficient technologies including approximately 868 MW of capacity from our power plants acquired in the Conectiv Acquisition which have conventional steam turbine technology. We also have approximately 4 MW of capacity from solar power generation technology at our Vineland Solar Energy Center in New Jersey.

Table of Operating Power Plants and Projects Under Construction

Set forth below is certain information regarding our operating power plants and projects under construction at December 31, 2011.

SEGMENT / Power Plant	NERC Region	U.S. State or Canadian Province	Technology	Calpine Interest Percentage	Calpine Net Interest Baseload (MW)[1][3]	Calpine Net Interest With Peaking (MW)[2][3]	2011 Total MWh Generated[4]
WEST							
Geothermal							
McCabe #5 & #6	WECC	CA	Geothermal	100%	78	78	684,076
Ridge Line #7 & #8	WECC	CA	Geothermal	100%	69	69	631,318
Calistoga	WECC	CA	Geothermal	100%	66	66	522,265
Eagle Rock	WECC	CA	Geothermal	100%	66	66	569,986
Quicksilver	WECC	CA	Geothermal	100%	53	53	383,283
Cobb Creek	WECC	CA	Geothermal	100%	52	52	425,984
Lake View	WECC	CA	Geothermal	100%	52	52	430,864
Sulphur Springs	WECC	CA	Geothermal	100%	51	51	422,585
Socrates	WECC	CA	Geothermal	100%	50	50	372,387
Big Geysers	WECC	CA	Geothermal	100%	48	48	468,186
Grant	WECC	CA	Geothermal	100%	43	43	309,729
Sonoma	WECC	CA	Geothermal	100%	42	42	304,220
West Ford Flat	WECC	CA	Geothermal	100%	24	24	221,138
Aidlin	WECC	CA	Geothermal	100%	17	17	132,180
Bear Canyon	WECC	CA	Geothermal	100%	14	14	102,764
Natural Gas-Fired							
Delta Energy Center	WECC	CA	Natural Gas	100%	835	857	4,163,744
Pastoria Energy Center	WECC	CA	Natural Gas	100%	750	729	2,911,112
Hermiston Power Project	WECC	OR	Natural Gas	100%	566	635	1,155,893
Otay Mesa Energy Center	WECC	CA	Natural Gas	100%	513	608	2,061,805
Metcalf Energy Center	WECC	CA	Natural Gas	100%	564	605	1,588,552
Sutter Energy Center	WECC	CA	Natural Gas	100%	542	578	952,805
Los Medanos Energy Center	WECC	CA	Natural Gas	100%	518	572	2,692,583
South Point Energy Center	WECC	AZ	Natural Gas	100%	520	530	805,650
Los Esteros Critical Energy Facility[5]	WECC	CA	Natural Gas	100%	—	188	66,547
Gilroy Energy Center	WECC	CA	Natural Gas	100%	—	141	31,853
Gilroy Cogeneration Plant	WECC	CA	Natural Gas	100%	109	130	42,998
King City Cogeneration Plant	WECC	CA	Natural Gas	100%	120	120	601,960
Greenleaf 1 Power Plant	WECC	CA	Natural Gas	100%	50	50	209,154
Greenleaf 2 Power Plant	WECC	CA	Natural Gas	100%	49	49	300,444
Wolfskill Energy Center	WECC	CA	Natural Gas	100%	—	48	9,889
Yuba City Energy Center	WECC	CA	Natural Gas	100%	—	47	14,753
Feather River Energy Center	WECC	CA	Natural Gas	100%	—	47	13,056
Creed Energy Center	WECC	CA	Natural Gas	100%	—	47	4,889
Lambie Energy Center	WECC	CA	Natural Gas	100%	—	47	5,500
Goose Haven Energy Center	WECC	CA	Natural Gas	100%	—	47	5,773
Riverview Energy Center	WECC	CA	Natural Gas	100%	—	47	11,279
King City Peaking Energy Center	WECC	CA	Natural Gas	100%	—	44	4,796
Agnews Power Plant	WECC	CA	Natural Gas	100%	28	28	187,034
Subtotal					5,889	6,919	23,823,034

SEGMENT / Power Plant	NERC Region	U.S. State or Canadian Province	Technology	Calpine Interest Percentage	Calpine Net Interest Baseload (MW)[1][3]	Calpine Net Interest With Peaking (MW)[2][3]	2011 Total MWh Generated[4]
TEXAS							
Deer Park Energy Center	TRE	TX	Natural Gas	100%	830	1,001	5,602,160
Baytown Energy Center	TRE	TX	Natural Gas	100%	782	842	4,240,920
Pasadena Power Plant	TRE	TX	Natural Gas	100%	763	781	3,898,928
Freestone Energy Center	TRE	TX	Natural Gas	75%	779	746	3,202,932
Magic Valley Generating Station	TRE	TX	Natural Gas	100%	662	692	3,748,570
Channel Energy Center	TRE	TX	Natural Gas	100%	463	608	2,742,657
Brazos Valley Power Plant	TRE	TX	Natural Gas	100%	520	606	2,325,886
Corpus Christi Energy Center	TRE	TX	Natural Gas	100%	426	500	2,545,531
Texas City Power Plant	TRE	TX	Natural Gas	100%	400	453	1,451,866
Clear Lake Power Plant	TRE	TX	Natural Gas	100%	344	400	821,766
Hidalgo Energy Center	TRE	TX	Natural Gas	79%	392	374	1,970,402
Freeport Energy Center[6]	TRE	TX	Natural Gas	100%	210	236	1,514,635
Subtotal					6,571	7,239	34,066,253
NORTH							
Bethlehem Energy Center	RFC	PA	Natural Gas	100%	1,037	1,130	4,105,331
Hay Road Energy Center	RFC	DE	Natural Gas	100%	1,030	1,130	3,919,934
Edge Moor Energy Center	RFC	DE	Natural Gas	100%	—	725	662,886
Riverside Energy Center	MRO	WI	Natural Gas	100%	518	603	859,844
York Energy Center	RFC	PA	Natural Gas	100%	519	565	1,300,635
Westbrook Energy Center	NPCC	ME	Natural Gas	100%	543	543	2,655,159
Greenfield Energy Centre[7]	NPCC	ON	Natural Gas	50%	422	519	1,549,488
RockGen Energy Center	MRO	WI	Natural Gas	100%	—	503	180,909
Zion Energy Center	RFC	IL	Natural Gas	100%	—	503	111,224
Mankato Power Plant	MRO	MN	Natural Gas	100%	280	375	339,617
Cumberland Energy Center	RFC	NJ	Natural Gas	100%	—	191	57,234
Deepwater Energy Center	RFC	NJ	Natural Gas	100%	—	158	47,252
Kennedy International Airport Power Plant	NPCC	NY	Natural Gas	100%	110	121	547,446
Sherman Avenue Energy Center	RFC	NJ	Natural Gas	100%	—	92	33,494
Bethpage Energy Center 3	NPCC	NY	Natural Gas	100%	60	80	218,715
Middle Energy Center	RFC	NJ	Oil	100%	—	77	2,204
Carll's Corner Energy Center	RFC	NJ	Natural Gas	100%	—	73	13,783
Cedar Energy Center	RFC	NJ	Oil	100%	—	68	1,773
Mickleton Energy Center	RFC	NJ	Natural Gas	100%	—	67	1,790
Missouri Avenue Energy Center	RFC	NJ	Oil	100%	—	60	2,134
Bethpage Power Plant	NPCC	NY	Natural Gas	100%	55	56	101,804
Christiana Energy Center	RFC	DE	Oil	100%	—	53	188
Bethpage Peaker	NPCC	NY	Natural Gas	100%	—	48	70,917
Stony Brook Power Plant	NPCC	NY	Natural Gas	100%	45	47	275,170
Tasley Energy Center	RFC	VA	Oil	100%	—	33	459
Whitby Cogeneration[8]	NPCC	ON	Natural Gas	50%	25	25	201,893
Delaware City Energy Center	RFC	DE	Oil	100%	—	23	41
West Energy Center	RFC	DE	Oil	100%	—	20	164
Bayview Energy Center	RFC	VA	Oil	100%	—	12	1,973
Crisfield Energy Center	RFC	MD	Oil	100%	—	10	427
Vineland Solar Energy Center	RFC	NJ	Solar	100%	—	4	4,841
Subtotal					4,644	7,914	17,268,729

SEGMENT / Power Plant	NERC Region	U.S. State or Canadian Province	Technology	Calpine Interest Percentage	Calpine Net Interest Baseload (MW)[1][3]	Calpine Net Interest With Peaking (MW)[2][3]	2011 Total MWh Generated[4]
SOUTHEAST							
Oneta Energy Center	SPP	OK	Natural Gas	100%	980	1,134	2,915,991
Broad River Energy Center	SERC	SC	Natural Gas	100%	—	847	741,260
Morgan Energy Center	SERC	AL	Natural Gas	100%	720	807	3,446,638
Decatur Energy Center	SERC	AL	Natural Gas	100%	782	795	4,451,786
Columbia Energy Center	SERC	SC	Natural Gas	100%	455	606	150,550
Osprey Energy Center	FRCC	FL	Natural Gas	100%	537	599	2,444,365
Carville Energy Center	SERC	LA	Natural Gas	100%	449	501	2,255,911
Hog Bayou Energy Center	SERC	AL	Natural Gas	100%	235	237	717,022
Santa Rosa Energy Center	SERC	FL	Natural Gas	100%	235	225	380,130
Pine Bluff Energy Center	SERC	AR	Natural Gas	100%	184	215	1,433,118
Auburndale Peaking Energy Center	FRCC	FL	Natural Gas	100%	—	117	45,802
Subtotal					4,577	6,083	18,982,573
Total operating power plants (92)					**21,681**	**28,155**	**94,140,589**
Projects under construction							
Russell City Energy Center [9]	WECC	CA	Natural Gas	75%	429	464	n/a
Los Esteros Critical Energy Facility (Upgrade)[5]	WECC	CA	Natural Gas	100%	120	120	n/a
Total operating power plants and projects					**22,230**	**28,739**	

(1) Natural gas-fired fleet capacities are derived on as-built as-designed outputs, including upgrades, based on site specific annual average temperatures and average process steam flows for cogeneration power plants, as applicable. Geothermal capacities are derived from historical generation output and steam reservoir modeling under average ambient conditions (temperatures and rainfall).

(2) Natural gas-fired fleet peaking capacities are primarily derived on as-built as-designed peaking outputs based on site specific average summer temperatures and include power enhancement features such as heat recovery steam generator duct-firing, gas turbine power augmentation and/or other power augmentation features. For certain power plants with definitive contracts, capacities at contract conditions have been included. Oil-fired capacities reflect capacity test results.

(3) These outputs 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.

(4) MWh generation is shown here as our net operating interest.

(5) Los Esteros Critical Energy Facility is currently under construction to upgrade from a 188 MW simple-cycle generation power plant to a 308 MW combined-cycle generation power plant.

(6) Freeport Energy Center is owned by Calpine; however, it is contracted and operated by The Dow Chemical Company.

(7) Calpine holds a 50% partnership interest in Greenfield Energy Centre through its subsidiaries; however, it is operated by a third party.

(8) Calpine holds a 50% partnership interest in Whitby Cogeneration through its subsidiaries; however, it is operated by Atlantic Packaging Products Ltd.

(9) Calpine holds a 75% majority interest in Russell City Energy Center.

We provide operations and maintenance services for all but three 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 operations and maintenance 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. Although we do not operate the Freeport Energy Center, our Turbine Maintenance Group performs all major maintenance services for this plant under a contract with The Dow Chemical Company through April 2032.

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 provide 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 some project financings may result in cross-defaults to certain of our other debt and debt instruments, including our First Lien Notes, Term Loan, New Term Loan and Corporate Revolving Facility. Acceleration of the maturity of a project financing following a default may also 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.

EMISSIONS AND OUR ENVIRONMENTAL PROFILE

Our environmental record has been widely recognized. We were 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 GHG emissions inventory with the California Climate Action Registry every year since 2003. In 2010, our emissions of GHG amounted to about 42 million tons.

Natural Gas-Fired Generation

Our natural gas-fired, primarily combined-cycle fleet consumes significantly less fuel to generate power than conventional boiler/steam turbine power plants and emits fewer air pollutants per MWh of power produced as compared to coal-fired or oil-fired power plants. All of our power plants have air emissions controls and most have selective catalytic reduction to further reduce emissions of nitrogen oxides, a precursor of atmospheric ozone. In addition, we have implemented a program of proprietary operating procedures to reduce natural gas consumption and further lower air pollutant emissions per MWh of power generated. The table below summarizes approximate air pollutant emission rates from our natural gas-fired, combined-cycle power plants compared to the average emission rates from U.S. coal-, oil- and natural 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]	Advantage Compared to Average U.S. Coal-, Oil-, and Natural Gas-Fired Power Plant
Nitrogen Oxide, NOx	1.94	0.14	92.8%
Acid rain, smog and fine particulate formation			
Sulfur Dioxide, SO_2	4.20	0.0064	99.8%
Acid rain and fine particulate formation			
Mercury Compounds[3]	0.000030	—	100%
Neurotoxin			
Carbon Dioxide, CO_2	1,858	904	51.3%
Principal GHG—contributor to climate change			

(1) The average U.S. coal-, oil- and natural gas-fired power plants' emission rates were obtained from the U.S. Department of Energy's Electric Power Annual Report for 2010. Emission rates are based on 2010 emissions and net generation. The U.S. Department of Energy has not yet released 2011 information.

(2) Our natural gas-fired, combined-cycle power plant estimated emission rates are based on our 2010 emissions and power generation data from our natural gas-fired combined-cycle power plants (excluding combined heat power plants) as measured under the EPA reporting requirements.

(3) The U.S. coal-, oil- and natural gas-fired power plant air emissions of mercury compounds were obtained from the U.S. EPA Toxics Release Inventory for 2010. Emission rates are based on 2010 emissions and net generation from U.S. Department of Energy's Electric Power Annual Report for 2010.

Geothermal Generation

Our 725 MW fleet of geothermal power plants utilizes a natural, 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), NO_X and SO_2 emissions. Compared to the average U.S. coal-, oil- and natural gas-fired power plant, our Geysers Assets emit 99.9% less NO_X, 100% less SO_2 and 96.8% 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 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.

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:

- We receive and inject an average of approximately 18 million gallons of reclaimed wastewater per day into the geothermal steam reservoir at The Geysers where the water is naturally heated by the Earth, creating additional steam to fuel our Geysers Assets. Approximately 14 million gallons is received from the Santa Rosa Geysers Recharge Project, developed by us and the City of Santa Rosa, which was previously being discharged into the Russian River, and we receive, on average, approximately 4 million gallons a day from The Lake County Recharge Project from Lake County.
- In our combined-cycle plants we use mechanical draft cooling towers, which consume up to 90 percent less water than conventional once-through cooling systems. Two of our combined-cycle plants employ air-cooled condensers, which consume virtually no water for cooling. We use once-through cooling systems at only two power plants, our Deepwater and Edge Moor power plants.
- 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 to four million gallons per day for an average power plant.
- Our Russell City Energy Center will use 100% reclaimed water from the City of Hayward's Water Pollution Control Facility for cooling and boiler makeup, which will prevent nearly four million gallons of wastewater per day from being discharged into the San Francisco Bay.

GOVERNMENTAL AND REGULATORY MATTERS

We are subject to complex and stringent energy, environmental and other laws and regulations at the federal, state and local levels as well as within the RTO and ISO markets in which we participate 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.

Environmental Matters

Federal Regulation of Air Emissions

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 existing federal and state performance standards mandated under the CAA. We continue to monitor and actively participate in EPA initiatives where we anticipate an impact on our business. Some of the more significant governmental and regulatory matters that affect our business are discussed below.

Criteria Pollutants and Hazardous Air Pollutants

The CAA requires the EPA to regulate emissions of pollutants considered harmful to public health and the environment. The EPA has set NAAQS for six "criteria" pollutants: carbon monoxide, lead, NO_2, particulate matter ("PM"), ozone and SO_2. In addition, the CAA regulates a large number of air pollutants that are known to cause or may reasonably be anticipated to cause adverse effects to human health or adverse environmental effects, known as hazardous air pollutants ("HAPs"). The EPA is required to issue technology-based national emissions standards for hazardous air pollutants ("NESHAPs") to limit the release of specified HAPs from specific industrial sectors.

Mercury and Air Toxics Standards

On December 21, 2011, the EPA issued the National Emission Standards for Hazardous Air Pollutants from Coal- and Oil-fired Electric Utility Steam Generating Units and Standards of Performance for Fossil-Fuel-Fired Electric Utility, Industrial-Commercial-Institutional, and Small Industrial-Commercial-Institutional Steam Generating Units, otherwise known as the Mercury and Air Toxics Standards ("MATS"). These rules limit, for the first time, emissions of mercury, acid gases and other metals from coal and oil-fired power plants. We are not directly affected by the rule because it does not apply to natural gas-fired units, peaker units or units that use fuel oil as a backup fuel. We believe that the proposed emission standards are sufficiently stringent to force coal units without emission controls to be retired or to install acid gas, mercury, and particulate matter controls by 2015, which could benefit our competitive position.

Cross-State Air Pollution Rule

On July 6, 2011, the EPA finalized rules to control interstate transportation of fine particulate matter (PM-2.5) and ozone. The Cross-State Air Pollution Rule ("CSAPR") requires substantial emissions reductions of NOx and SO_2 from electric generating units in 27 states primarily in the eastern U.S. The rule sets up three distinct cap-and-trade programs: annual NOx and SO_2 trading programs to control fine particles, and a NOx trading program from May through September (the ozone season) to control ozone. Emission reductions were scheduled to take effect starting January 1, 2012 for SO_2 and annual NOx reductions and May 1, 2012 for ozone season NOx reductions. Significant additional SO_2 emission reductions in Group 1 states will be required in 2014. Compared to 2005, the EPA estimates that by 2014 this rule and other federal rules will lower power plant annual emissions in the CSAPR region by 6.4 million tons per year of SO_2 (a 73% reduction) and 1.4 million tons per year of NOx (a 54% reduction). The rule established an unlimited intrastate and limited interstate trading program with allowances allocated to sources based on historic heat input but capped at maximum annual emissions from 2003 to 2010. At current capacity factors, Calpine will be allocated sufficient allowances; thus, CSAPR is not expected to have a material impact on our operations. We expect the overall impact of this rule to be a net positive to Calpine as the significant emission reductions require coal-fired electric generating units to either purchase allowances, switch to more expensive fuels, install air pollution controls, or reduce or discontinue operations.

On October 14, 2011, the EPA proposed revisions to CSAPR to address discrepancies in unit-specific modeling assumptions that affect state budgets in Texas, Florida, Louisiana, Michigan, Mississippi, Nebraska, New Jersey, New York and Wisconsin. In addition, the EPA proposed delaying the assurance provisions, which were established to ensure that states' emissions do not exceed their emissions budgets plus a variability allowance. The proposed two-year delay in the assurance provisions would allow unlimited interstate trading of CSAPR allowances, thereby providing more compliance options for affected sources. In addition, the EPA finalized a supplemental rule that includes five additional states - Iowa, Michigan, Missouri, Oklahoma and Wisconsin - in CSAPR's seasonal NOx emission trading program.

A number of power generation companies, states and other groups have filed petitions for review in the U.S. Court of Appeals for the D.C. Circuit ("D.C. Circuit") challenging CSAPR. Several of these petitioners have also filed motions for either full or partial stays of the Rule. Calpine and other power generation companies have been granted intervenor status on behalf of respondent EPA. On December 30, 2011, the D.C. Circuit stayed CSAPR pending the court's review of the merits of the challenges to CSAPR. The court also restored CSAPR's predecessor, CAIR, for the 2012 compliance year. Calpine continues to participate as a respondent intervenor in the court proceedings.

CAIR and Multi-Pollutant Program

Pursuant to authority granted under the CAA, the EPA promulgated the Clean Air Interstate Rule, or CAIR, regulations in March 2005, applicable to 28 eastern states and the District of Columbia, to facilitate attainment of its ozone and fine particulates NAAQS issued in 1997. CAIR's goal is to reduce SO_2 emissions in these states by over 70%, and NOX emissions by over 60% from 2003 levels by 2015. CAIR established 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 the "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 CAIR 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 is positive. As part of the stay of CSAPR, the DC Circuit reinstated CAIR for the 2012 compliance year.

GHG Emissions

On April 2, 2007, the U.S. Supreme Court ruled that the EPA has the authority to regulate GHG emissions under the CAA. As a result of this ruling, the EPA is moving forward to regulate GHG emissions pursuant to its existing authority under the CAA. On December 7, 2009, the EPA made an "endangerment finding" with respect to GHGs, determining that current and projected concentrations of six key GHGs endanger the public health and welfare of current and future generations. As part of the EPA's initiative to regulate GHGs, on May 13, 2010, the EPA finalized regulations referred to as the "Tailoring Rule" to require new sources emitting over 100,000 tons per year (a "major" source) of GHG emissions or modifications to existing major sources that would increase their GHG emissions by greater than 75,000 tons per year to undergo a major new source review ("NSR"). Beginning in January 2011, sources or modifications already required to obtain a prevention of significant deterioration ("PSD") permit due to their emissions of conventional regulated pollutants were required to satisfy best available control technology ("BACT") requirements for GHG as well. Beginning in July 2011, new sources and modifications exceeding the 100,000 and 75,000 tons per year thresholds, respectively, were required to obtain a PSD permit and satisfy BACT requirements for GHGs, regardless of their emissions of any conventional pollutants. The EPA has issued guidance to permitting authorities on the implementation of GHG BACT that focuses on energy efficiency, but requires consideration of carbon capture and storage ("CCS") as available technology for high-emitting industries, although the EPA acknowledges that CCS may be eliminated as technically infeasible or excessively costly at this time. We believe that the impact of the final Tailoring Rule will be neutral to us because we expect that our efficient power plants would be found to meet BACT for GHGs if required to undergo PSD review.

On August 2, 2010, a coalition of approximately 20 members representing manufacturing, oil and gas facilities, refineries, and small businesses, filed a petition for review of the Tailoring Rule. The petition was consolidated with a prior petition from the coalition challenging the EPA's "Timing Rule," which clarified the timeframe for PSD regulation of GHGs to take effect, and numerous related petitions filed by states, environmental organizations, and other industry groups. There are currently over 70 parties in the consolidated litigation, *Coalition for Responsible Regulations, Inc. v. U.S. Environmental Protection Agency*. Oral argument for all of the petitions challenging the EPA's suite of GHG regulations and policies is set for February 28-29, 2012 in the D.C. Circuit.

Fees on Permissible Emissions

Section 185 of the CAA requires major stationary sources of NOx and volatile organic compounds ("VOCs"), such as power plants and refineries, in areas that fail to attain the NAAQS for ozone by the attainment date to pay a fee to the state or in the absence of state action, the EPA. The fee was set by Congress in the CAA at $5,000 per ton of NOx or VOC (adjusted for inflation or approximately $9,000 per ton in 2011) and is payable on emissions that exceed 80% of each individual power plant's baseline emissions, which were established in the year before the attainment date; however, the EPA is considering alternative baseline calculations. The fee will remain in effect until the designated area achieves attainment. We operate 13 power plants that are located within designated nonattainment areas in Texas, New York, and New Jersey, which are subject to this fee. On January 5, 2010, the EPA issued guidance on developing fee programs required under Section 185 of the CAA. Texas issued a draft rulemaking to collect the fees in late 2009; however, Texas inactivated the proposed rulemaking in 2010. We estimate that compliance with this fee could result in additional costs of approximately $2 million to $4 million on an annual basis and our financial statements include accruals for our estimated Section 185 fees. Our estimate is dependent upon a number of factors that could change in the future dependent upon, among other things: implementation by the states of guidance from the EPA, state rulemakings, the designation of nonattainment status, our number of power plants located in these areas and our level of NOx emissions.

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 plants 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 plants. 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. Our Edge Moor and Deepwater power plants currently receive sufficient free SO_2 allowances; therefore, we will have no compliance expense for this program.

Regional and State Air Emissions 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 include the RGGI in the northeast states and California's implementation of its own GHG policy pursuant to AB 32, including its RPS. The evolution of these programs could have a material impact on our business.

California: GHG (AB 32)

California's AB 32 creates a statewide cap on GHG emissions and requires the state to return to 1990 emission levels by 2020. On October 20, 2011, the CARB adopted final cap-and-trade and mandatory reporting regulations which were approved by the Office of Administrative Law on December 15, 2011. The regulations took effect on January 1, 2012 and CARB has begun to implement the program. The first compliance year when covered sources, including Calpine, will have to turn in allowances has been moved from 2012 to 2013; however, CARB is implementing other requirements of the regulation including registering covered entities, putting in place and testing the necessary infrastructure, and conducting two auctions in August and November of 2012. Litigation challenging the implementation of CARB's AB 32 Scoping Plan has been resolved and there are currently no challenges to the Scoping Plan or the cap-and-trade regulations. However, we cannot predict whether there will be new legal challenges filed against the regulation or what the associated impacts of any such litigation would be. A number of parties continue to seek further refinements to improve the regulation. Concurrent with the adoption of the regulations, on October 20, 2011, CARB also adopted Resolution 11-32 outlining the issues it will continue to address including, but not limited to, issues raised by Calpine on the market's auction purchase and holding limit rules and issues involving long-term contracts executed prior to AB 32. CARB has recently announced that it will consider these issues in two new rulemakings in the second and fourth quarters of 2012. Overall, we support AB 32 and believe we are favorably positioned to comply with these regulations.

Northeast and Mid-Atlantic: CO_2 (RGGI)

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, New Jersey and Delaware (together emitting about 3.9 million tons of CO_2 annually). In 2011, New Jersey announced that it will withdraw from the RGGI program effective for the compliance year 2012. 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 have recently cleared at the program's floor price of $1.86 per ton. 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 power plants in the RGGI region. We have also received annual allocations from New York's long-term contract set-aside pool to cover some of the CO_2 emissions attributable to our PPAs at both the Kennedy International Airport Power Plant and Stony Brook Power Plant, and we received allowances for our power plants in Delaware pursuant to the state's allowance allocation program. We do not anticipate any significant business impact from RGGI, given the efficiency of our power plants in RGGI states.

Texas: NO_X

Pursuant to authority granted under the CAA, regulations adopted by the Texas Commission on Environmental Quality ("TCEQ") to attain the one-hour and eight-hour NAAQS for ozone included the establishment of a cap-and-trade program for NO_X emitted by power plants in the Houston/Galveston ozone nonattainment area. We own and operate seven power plants that participate in this program, all of which received free NO_X allowances based on historical operating profiles. At this time, our Houston-area power plants have sufficient NO_X allowances to meet forecasted obligations under the program.

New Jersey: NO_X

New Jersey has enacted air regulations that limit the number of hours some of our New Jersey assets will be permitted to operate. These regulations will require future investment in emission controls on some of our units. Our 158 MW Deepwater power plant and certain of the New Jersey peaker power plants will need additional NO_X controls to continue operating beyond May 1, 2015 under the regulations. We are currently evaluating the cost to comply with these air regulations and are uncertain of the impact to our financial position or results of operations.

Other

Other states where our power plants are located may implement state or regional CO_2 compliance requirements. The Western Climate Initiative, 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 Western Climate Initiative'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. Some partner states, such as Arizona, have indicated their participation will be delayed or dependent on further economic analysis and recovery. To date, California and Quebec are the only members that have reaffirmed their commitment to participate in the Western Climate Initiative, with both committing to begin cap-and-trade in 2013.

Renewable Portfolio Standards

Policymakers have been considering variations of an 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 power generated from renewable or clean energy resources by a certain date.

Federal RPS

Although there is currently no national RPS, President Obama has stated his goal is to have 80% of the nation's electricity provided from clean energy resources, which includes natural gas resources, by 2035, and some U.S. Congressional leaders have continued to press for a national renewable or clean energy standard 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 power plants could benefit by providing complementary/back-up service for these intermittent renewable resources or by being included in a clean energy standard.

California RPS

On April 12, 2011, California's governor signed into law legislation establishing a new and higher RPS. The new law requires implementation of a 33% RPS by 2020, with intermediate targets between now and 2020. The previous RPS legislation required certain retail power providers to generate or procure 20% of the power they sell to retail customers from renewable resources beginning in 2010. The new standard applies to all load-serving entities, including entities such as large municipal utilities that are not CPUC-jurisdictional. Under the new law, there are limits on different "buckets" of procurement that can be used to satisfy the RPS. Load-serving entities must satisfy at least a fraction of their compliance obligations with renewable power from resources located in California or delivered into California within the hour. Similarly, the legislation places limits on the use of "firmed and shaped" transactions and unbundled RECs - claims to the renewable aspect of the power produced by a renewable resource that can be traded separately from the underlying power. In general, the ability to use "firmed and shaped" transactions and unbundled RECs becomes more limited over the course of the implementation period. On December 1, 2011, the CPUC issued a decision on intermediate RPS procurement targets between the present and 2020. On December 15, 2011 the CPUC issued a decision clarifying exactly what transactions will fall into which bucket. Important additional details of the implementation of the 33% RPS are the subject of ongoing regulatory proceedings at both the CPUC and the California Energy Commission.

Other

A number of additional states have an 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.

Other Environmental Regulations

In addition to air emissions, our power plants and the equipment necessary to support them are subject to other 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 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 may also 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 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, for 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.

Section 316(b) of the Clean Water Act requires that the location, design, construction and capacity of cooling water intake structures reflect the best technology available for minimizing adverse environmental impact. On March 28, 2011, the EPA proposed rules (the "Water Intake Rule") that would allow states to require power plants employing older once-through cooling systems, particularly along biologically productive estuaries and rivers, to undertake major modifications to their cooling water intake structures or even install cooling towers to reduce impingement (where fish and other aquatic life get trapped against the intake screens) and entrainment (where small aquatic life passes through the intake screens and goes through the condenser at high temperatures). While these rules will likely affect our competitors, we do not expect these rules to have a material impact on our operations because we have only two peaking power plants that employ once-through cooling.

In California, the EPA delegates the implementation of 316(b) to the California State Water Resources Control Board ("SWRCB"). SWRCB has promulgated its own once-through cooling policy that established a schedule for once-through cooling units to install cooling towers or reduce entrainment and impingement to comparable levels as would be achieved with a cooling tower, or be retired. The compliance dates for approximately 12,000 MW of once-through cooling capacity in California occur between now and 2020.

Safe Drinking Water Act

Part C of the Safe Drinking Water Act establishes the underground injection control program that regulates the disposal of wastes by means of deep well injection. Although geothermal production wells, which are wells that bring steam to the surface, are exempt under the Energy Policy Act of 2005 ("EPAct 2005"), we use geothermal re-injection wells to inject reclaimed wastewater back into the steam reservoir, which are subject to this regulation. We believe that we are in material compliance with Part C of this Act.

Resource Conservation and Recovery Act

The Resource Conservation and Recovery Act ("RCRA"), regulates the management of solid and hazardous waste. With respect to our solid waste disposal practices at our power plants 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.

On June 21, 2010, the EPA proposed rules to regulate coal combustion residuals ("CCRs") under RCRA. The EPA seeks to establish more stringent dam safety requirements to enhance performance of CCRs managed in surface impoundments. The EPA also seeks to regulate disposal of CCRs and has proposed to either regulate them as hazardous waste under Subtitle C of RCRA, or as nonhazardous waste under Subtitle D of RCRA. Both options will impose additional waste management costs on our competitors who rely on coal as a fuel. The EPA estimates a net present value cost of $3 billion to $21 billion to coal plants. We do not use coal so these rules will have no direct impact on us.

Comprehensive Environmental Response, Compensation and Liability Act

The Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), also referred to as the 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 filing of this Report, 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 a liability under CERCLA in the future.

New Jersey Environmental Programs

New Jersey has a program mandating the cleanup of sites where there has been a release of a hazardous substance. As part of the Conectiv Acquisition on July 1, 2010, we assumed environmental remediation liabilities related to certain of the assets located in New Jersey that are subject to the ISRA. We have accrued or paid $10 million related to these liabilities at December 31, 2011. Pursuant to the Conectiv Purchase Agreement, PHI is responsible for any amounts that exceed $10 million associated with

New Jersey environmental remediation liabilities. Our accrual is included in our allocation of the Conectiv Acquisition purchase price. See Note 3 of the Notes to Consolidated Financial Statements for disclosures related to our Conectiv Acquisition.

Federal Litigation on Liability for Air Emissions

In the absence of federal climate change legislation, litigation relating to GHG emissions is working its way through the federal courts. Federal court decisions are divided as to whether large emitters of GHGs may be sued under common law theories of nuisance and negligence.

On September 21, 2009, the Second Circuit issued a ruling in *State of Connecticut, et al. v. American Electric Power Company Inc., et al.*, reversing a lower court's dismissal of two public nuisance claims filed by various states, municipalities and private entities against operators of coal-fired power plants. Plaintiffs argued that the power plant defendants contribute to global warming by emitting 650 million tons of CO_2 per year and these emissions are causing and will continue to cause serious harm affecting human health and natural resources. The lower court held that plaintiffs' claims presented a non-legal political question and dismissed the complaints. The Second Circuit vacated the lower court's decision, ruling in favor of the plaintiffs. The Second Circuit's decision was appealed to the U.S. Supreme Court. On June 20, 2011, the Supreme Court issued a decision rejecting the plaintiffs' federal common law claim. The Court found that even if a federal common law claim could be made by plaintiffs, the CAA essentially "displaced" that claim. The case was remanded to the Second Circuit for further consideration of other issues in the case, including whether the plaintiffs may raise their claims under state common law or whether those claims are also preempted by federal law. The Second Circuit remanded to the district court for additional fact-finding. On December 6, 2011, the case was voluntarily dismissed. We cannot predict what impact the precedent of this case could have on our business.

The Supreme Court's decision in the above matter is expected to have consequences for other climate change cases that are in the Fourth, Fifth, and Ninth Circuit courts of appeal, including *Native Village of Kivalina v. ExxonMobil*. In *Kivalina*, a federal district court in California sided with the defendants, 24 oil, energy and utility companies, against the Village of Kivalina, a small, self-governing tribe of Inupiat people who reside north of the Arctic Circle. The residents of Kivalina had sued the defendants for damages under federal nuisance law arguing that, as a result of global warming, Kivalina is subject to coastal storm waves and surges. On September 30, 2009, the court ruled in favor of the defendants finding that the plaintiff's global warming claim was based upon the emission of GHGs from innumerable sources located throughout the world affecting the entire planet and its atmosphere and that no federal standards limit the discharge of GHGs. *Kivalina* is currently on appeal to the Ninth Circuit court. A three-judge panel of the Ninth Circuit heard oral arguments on November 28, 2011. We cannot predict the outcome of this case or what impact the precedent of this case could have on our business.

Power and Natural Gas Matters

Federal Regulation of Power

FERC Jurisdiction

Electric utilities have been highly regulated by the federal government since the 1930s, principally under the Federal Power Act ("FPA"), and the U.S. Public Utility Holding Company Act of 1935. These statutes have been amended and supplemented by subsequent legislation, including PURPA, EPAct 2005, and PUHCA 2005. These particular statutes and regulations are discussed in more detail below.

The FPA grants the federal government broad authority over electric utilities and independent power producers, 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, the terms and conditions for the transmission or wholesale sale of power in interstate commerce, the 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; however, certain power plants 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 books and records inspection rights pursuant to one of the limited exemptions under PUHCA 2005 as we are a holding company due solely to our owning one or more QFs, EWGs and Foreign Utility Companies ("FUCOs"). If any of our entities 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 rules will continue to evolve, and FERC may amend or revise them, or may introduce new policies or rules in the future. The impact of such policies and rules 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 certain of those power plants that are QFs under PURPA or 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.

Market-based rate 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. If market-based rate authority were revoked or restricted, affected power plants could be required to make wholesale sales of power based on cost-of-service rates, which could negatively impact their revenues.

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 ("PURPA put"). 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 under the PURPA put if FERC determines that such QFs have access to a competitive wholesale power market.

Station Power Ruling

On August 30, 2010, FERC issued an order on remand ("remand order") regarding its station power policies in response to a ruling by the D.C. Circuit. The D.C. Circuit's ruling vacated and remanded FERC's prior orders on CAISO's station power procedures, finding that FERC had not adequately justified its decision that no retail sale occurs when a generator self-supplies station power over a monthly netting period. In its remand order, FERC reversed its prior orders relating to a generator's self-supply of station power in the markets administered by CAISO, concluding that FERC's jurisdiction covers only the transmission of station power and the states have exclusive jurisdiction to determine when the use of station power results in a retail sale. The remand order could impact FERC's station power policies in all of the organized markets throughout the nation. Calpine and several other generators filed an appeal of FERC's decision. If left unchanged, FERC's remand order could result in our power plants paying more for station power service. However, we do not believe such increases will be material to us.

FERC Credit Reforms in Organized Wholesale Electric Markets

In October 2010, FERC issued a final rule regarding credit reforms in the organized wholesale electric markets. The reforms include shortening the settlement timeframes, restricting or eliminating the use of unsecured credit, clarifying the ability to offset market obligations, establishing minimum criteria for market participation, and establishing and clarifying when an ISO or RTO may require additional collateral from market participants for a material adverse change. ISO and RTO compliance filings were submitted in June 2011. Many of the credit rules took effect on October 1, 2011, with additional requirements being developed by the ISOs and RTOs. The credit rules and procedures for each ISO and RTO differ in requirements and compliance obligations. We continue to work to enhance uniformity and compliance obligations among the ISOs and RTOs, but we do not believe these changes to FERC's credit rules will have a material impact on our business.

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 Electric Reliability Organization to develop and oversee the enforcement of electric system reliability standards applicable throughout the U.S., which are subject to FERC review and approval. FERC-approved reliability standards may be enforced by FERC independently, or, alternatively, by the Electric Reliability Organization 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 (purchasing and selling entity) are effective and mandatory. In addition, the regional reliability organizations have the ability to formulate supplemental reliability standards to apply in their specific regions, which may be more stringent than the NERC reliability standards. We comply with different reliability standards, requirements and procedural rules in each region in which we operate. It is expected that additional or modified 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, Texas and North because these are the regions in which we have the most significant portfolios of power plants. 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 as significant. All power plant and MW data is reported as of December 31, 2011.

West

We have 24 natural gas-fired power plants, including 2 under construction, with the capacity to generate a total of 6,194 MW in the WECC NERC 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 a power plant in Arizona and one in 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 transmission constraints arise. The controls and the markets themselves are subject to regulatory change at any time. CAISO runs integrated day-ahead and real-time markets for energy and ancillary services. The energy markets include centralized, day-ahead and real-time markets 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 energy bid cap of $1,000 per MWh. The locational marginal pricing market design is intended to reward and encourage generation resources on favorable grid locations, such as some of the locations of our power plants.

Our Sutter power plant, which is a 578 MW combined-cycle natural gas-fired power plant, has no contracts for its output in 2012. In late 2011, we determined that the power plant will be uneconomic and may have to be shut down absent incremental compensation. Consequently, on November 22, 2011, we submitted a request to the CAISO to compensate our Sutter power plant under a provision of CAISO's current tariff that is intended to avoid retirement of needed generating units. This tariff provision, the Capacity Procurement Mechanism ("CPM"), allows the CAISO to compensate assets that are needed in the future, but are not currently receiving sufficient revenues to sustain operation. Upon review of our request, the CAISO determined we had met all of the requirements for such compensation. However, the CAISO also determined that the need for our Sutter power plant cannot be demonstrated in the following year (as required by the current tariff), but some time later. On January 26, 2012, the CAISO submitted a request to FERC seeking a narrow waiver of its tariff to allow such designation and compensation for our Sutter power plant. In parallel, we submitted a notice to the CPUC indicating that the operational status of our Sutter power plant may change. In a separate action, the CPUC has issued a draft resolution directing the state-jurisdictional load serving entities to enter into contracts sufficient to preserve our Sutter power plant through 2012. The resolution will be considered at the February 15, 2012 CPUC meeting. The outcome of these proceedings is uncertain at this time.

A recently implemented CPUC settlement changes significant aspects of policy towards California QFs, including our non-renewable QF facilities. The settlement resolves issues related to QFs under existing QF contracts. Most existing California QFs are under QF contracts. The settlement establishes new energy pricing options for QFs under QF contracts, including the option to shed QF host and efficiency obligations and become dispatchable, and specifies mechanisms for the California IOUs to procure both existing combined heat and power ("CHP") that is not otherwise under contract and new CHP. Pursuant to the QF Settlement, we have converted one of our former QFs to a dispatchable non-QF unit and are exploring similar opportunities for some of our other California QFs. In addition, we plan to participate in the IOUs' upcoming CHP solicitations.

Our power 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

We have 12 natural gas-fired power plants in the TRE NERC region with the capacity to generate a total of 7,239 MW, all of which are physically located in the ERCOT market. ERCOT is the 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 markets. 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 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 power and capacity services to ERCOT.

ERCOT implemented a nodal market structure on December 1, 2010. A nodal market structure results in locational marginal pricing at each generation location rather than establishing pricing in four zones as was done prior to December 1, 2010.

The PUCT initiated a Resource and Reserve Adequacy and Shortage Pricing proceeding and held workshops during the summer of 2011 to examine the factors affecting ERCOT's annual planning reserve margins and the effects of the deployment of operating reserves on shortage pricing in the region's energy-only market design. The effect of the initiative thus far has been the establishment of price floors of $120/MWh for on-line non-spin and $180/MWh for off-line non-spin when contingency reserves are deployed. At the direction of the PUCT, stakeholders and ERCOT are considering additional changes which include a corresponding reduction in non-spinning reserve service and increase in responsive reserves, establishing a floor for reliability

unit commitment units deployed for capacity and changing the slope and price cap for the power balance penalty curve. The PUCT requested action on these proposals by the end of the second quarter of 2012. If some or all of these changes are adopted, we expect more scarcity pricing opportunities, which should have a positive impact on our Commodity Margin.

The Sunset Review Process, implemented by the Texas Legislature in 1977, is the regular assessment of the need for a state agency to exist and to consider new and innovative changes to improve each agency's operations and activities. The Sunset Review Process works by setting a date on which an agency will be abolished unless legislation is passed to continue its functions. The Sunset Review Process began in September 2009 for the PUCT and ERCOT and concluded in April 2010. The TCEQ and Texas Railroad Commission reviews began in April 2010 and were completed in December 2010. While significant changes were proposed at the Commission level, the legislation containing the proposed changes did not reach final passage during the 2011 legislative session. Therefore, another review of these agencies will begin and any resulting legislation will be considered in the 2013 legislative session.We cannot predict which changes, if any, will be placed into legislation and ultimately reach final passage. We will continue to participate in these processes where we anticipate an impact on our business; however, we do not expect such changes, if any, will have a material impact on our operations.

On July 17, 2008, the PUCT tentatively approved a transmission build plan, the Competitive Renewable Energy Zones, or CREZ, to expand the delivery of wind-generated power 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 plants is unknown.

North

We have a total of 31 power plants with 7,914 MW of peaking capacity located in the RFC, NPCC and MRO NERC regions.

We have 19 operating power plants with the capacity to generate a total of 4,491 MW in Eastern PJM. In addition, we have one operating power plant, with the capacity to generate 503 MW, located in Western PJM. However, this power plant is partially committed to load in MISO. Eastern PJM and Western PJM are both located in the RFC NERC region. 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.

Recently, certain states in the PJM market region have taken actions that could impact the PJM capacity market. In New Jersey, legislation enacted in 2011 required the New Jersey Board of Public Utilities ("BPU") to issue a request for proposals ("RFP") for new generation. Market participants and others were concerned that awarding long-term contracts could impact the clearing prices of future PJM capacity auctions. The BPU has also initiated a proceeding and held hearings to investigate whether there is a need for New Jersey to pursue additional generation capacity beyond the 2,000 MW already contracted for pursuant to the legislation. Meanwhile, in response to a filing by PJM that was intended in part to address the negative implications from these state actions by revising the Minimum Offer Price Rule ("MOPR") in its tariff, FERC issued an order on April 12, 2011 approving PJM's MOPR tariff changes. Also, on February 9, 2011, we joined a group of generators and utilities in filing a complaint in federal district court challenging the constitutionality of the New Jersey legislation. The court proceeding is continuing.

On September 29, 2011, the Maryland Public Service Commission ("MPSC") issued a "Notice of Approval of Request for Proposals for New Generation to be Issued by Maryland Electric Distribution Companies." The Notice required the state's IOUs to issue RFPs for up to 1,500 MW of capacity. The Notice specifies that proposals must be for new natural gas-fired capacity capable of delivery into the PJM Southwest Mid-Atlantic Area Council delivery area. The MPSC held a hearing on January 31, 2012 to determine whether new capacity is required, but it has not issued a final order in this proceeding.

We have a total of eight natural gas-fired power plants with the capacity to generate a total of 1,439 MW in the NPCC NERC region. 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 zonal marginally accepted bid price for the energy it produces.

Our remaining U.S.-based power plant in the NPCC NERC region 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% ownership interests in two Canadian power plants, with the total capacity to generate 1,088 MW (544 MW net attributable to Calpine), located in the NPCC NERC region in Ontario, Canada. The Whitby cogeneration facility is a 50 MW facility located in Whitby, Ontario and the Greenfield Energy Centre is a 1,038 MW facility located in Courtright, Ontario. The Independent Electricity System Operator ("IESO") of Ontario 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. Effective December 2009, the IESO of Ontario implemented several rule changes that impacted Greenfield LP's financial performance in 2010 and 2011 and will impact Greenfield LP in future years. Greenfield LP's power supply contract with the Ontario Power Authority provides it with a right to recover for financial consequences of market rule changes that negatively impact Greenfield LP; however, after extended negotiations to modify the agreement to address the financial impacts, Greenfield LP has initiated arbitration as provided for under the power supply contract to preserve its recovery rights. We continue to pursue arbitration of this matter and cannot predict at this time the outcome of arbitration, or the potential impact, if any, to our 50% partnership interest in Greenfield LP.

We have three natural gas-fired power plants with the capacity to generate a total of 1,481 MW operating within the MRO NERC region. MISO manages competitive locationally based wholesale day-ahead, real-time energy and ancillary services markets. MISO's Resource Adequacy model requires load serving entities to account for capacity obligations under Module E of the MISO tariff. MISO currently conducts a monthly voluntary capacity auction to help purchasers find suppliers with capacity to meet their incremental capacity needs. In July 2011, MISO filed with FERC a proposal to re-design its current capacity market. Among other things, the proposed design would move MISO from a monthly capacity product to an annual capacity product, implement annual auctions, and make market participation mandatory for all load-serving entities as well as generators.

Southeast

We have one operating natural gas-fired power plant with the capacity to generate 1,134 MW located in the SPP NERC region. SPP is an RTO approved by FERC that provides independent administration of the electric power grid. SPP currently manages an energy-only location based real-time wholesale energy market. This market provides both nominal load-following and transmission constraint relief. In April 2011, the SPP board of directors voted to implement the market designs for a full suite of "Day 2" markets, including a day-ahead energy market, a financial transmission rights market, and ancillary service markets. The SPP staff and stakeholders have since entered into contracts with vendors to design the implementing elements and software to support this initiative. These new markets are scheduled to be implemented in March 2014.

We have ten natural gas-fired power plants with the capacity to generate a total of 4,949 MW operating within the SERC and the FRCC NERC regions. Opportunities to negotiate bilateral, individual contracts and long-term transactions with IOUs, municipalities and cooperatives exist within these regions. 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 Independent Coordinator of Transmission. In this capacity, the Independent Coordinator of Transmission provides oversight of the Entergy transmission system.

Entergy and MISO continue to move forward with their proposal to transfer functional control of Entergy's transmission system to MISO by December 2013. Last fall, Entergy filed change of control applications with the Arkansas Public Service Commission, the City of New Orleans, the Louisiana Public Service Commission, and the Mississippi Public Service Commission, but no concluding order has been issued by these regulatory bodies. Entergy is expected to, but has not made, a similar filing with the Public Utility Commission of Texas. We support Entergy membership in an RTO as soon as possible, with a preference for MISO. SPP continues to publicly oppose the Entergy to MISO proposal and asserts that Entergy should integrate its system with SPP.

Other State Regulation of Power

State Public Utility Commissions, or PUC(s), 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. Since 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.

State PUCs also maintain extensive control over the procurement of wholesale power by the utilities that they regulate. Many of these utilities are our customers, and agreements between us and these counterparties often require approval by state PUCs. For example, in California, the CPUC determines how much new generation can be purchased by the IOUs, and shapes

the rules of the IOUs' requests for offers. In addition, the CPUC determines the rules of California's Resource Adequacy program. The Resource Adequacy program is currently based on a loosely structured year- and month-ahead bilateral capacity market.

Regulation of Transportation and Sale of Natural Gas

Since the majority of our power generating capacity is derived from natural gas-fired 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 Natural Gas Policy Act ("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.

We also operate a proprietary pipeline system in California, which is regulated by the U.S. Department of Transportation and the Pipeline and Hazardous Materials Safety Administration with regard to safety matters. Additionally, some of our power plants own and operate short pipeline laterals that connect the natural gas-fired power plants to the North American natural gas grid. Some of these laterals are subject to state and/or federal safety regulations.

Under the Natural Gas Act ("NGA"), the NGPA and the Outer Continental Shelf Lands Act, FERC is authorized to regulate pipeline, storage and liquefied natural gas, or 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 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.

Federal Regulation of Futures and Other Derivatives

CFTC Regulation of Futures Transactions

The CFTC has regulatory oversight of the futures markets, including trading on NYMEX for energy, and licensed futures professionals such as 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. We also expect the CFTC's future powers and oversight to be increased by the Dodd-Frank Act (discussed below).

The Dodd-Frank Wall Street Reform and Consumer Protection Act of 2010

CFTC Regulation of Derivatives Transactions

The Dodd-Frank Act was signed into law on July 21, 2010. Many aspects of the Dodd-Frank Act are subject to rulemaking that will take effect over several years, thus making it difficult to assess its impact on us at this time. The Dodd-Frank Act contains a variety of provisions designed to regulate financial markets, including credit and derivatives transactions.

Title VII of the Dodd-Frank Act addresses regulatory reform of the OTC derivatives market in the U.S. and significantly changes the regulatory framework of this market. Currently, the effective date for the CFTC to implement all final regulations related to Title VII is July 16, 2012. Certain Title VII regulations have been finalized, however, other key regulations have not been finalized as of this time. Until all of these regulations have been finalized, the extent to which the provisions of Title VII might affect our derivatives activities is unknown. A number of features in the legislation may impact our existing business. One of these is the requirement for central clearing of many OTC derivatives transactions with clearing organizations. This requirement is subject to an end-user exception. Whereas our OTC transactions have traditionally been negotiated on a bilateral basis, including the collateral arrangements thereunder, they now may be subject to the collateral and margining procedures of the clearing organization. The CFTC is also finalizing the regulation which will guide us in determining if we qualify as a commercial end-

user under the regulation. If we do not qualify as a commercial end-user, it is highly likely that we will be required to register as a dealer of commodities with the CFTC, and we will be required to perform additional activities within our transaction processes to comply with the regulations; however, our compliance activities will not have a material adverse effect on our financial position or results of operations. Other features of the Dodd-Frank Act which will have an impact on our derivatives activities include trade reporting, position limits and trade execution. The effect of the Dodd-Frank Act on traditional dealers and market-makers as well as the consequential effect on market liquidity and, hence, pricing is uncertain; however, we expect to be able to continue to participate in financial markets for our derivative transactions.

Other provisions

The Dodd-Frank Act also requires regulatory agencies, including the SEC, to establish regulations for implementation of many of the provisions of the Dodd-Frank Act. While we are closely monitoring this rulemaking process, the exact impact of new rules on our business remains uncertain. We will continue to monitor all relevant developments and rulemaking initiatives, and we expect to successfully implement any new applicable legislative and regulatory requirements. At this time, we cannot predict the impact or possible additional costs to us, if any, related to the implementation of, or compliance with, the potential future requirements under the Dodd-Frank Act.

Geothermal Operations

The focus on induced seismicity caused by hydro-fracturing associated with natural gas and geothermal exploration and production could cause government entities or agencies to more stringently regulate that activity and such regulation could impact the exploration, development and operation of geothermal power plants, including our Geysers Assets.

EMPLOYEES

At December 31, 2011, we employed 2,101 full-time employees, of whom 150 were represented by collective bargaining agreements. We have 91 employees represented by collective bargaining agreements which expire within one year. We have never experienced a work stoppage or strike.

Item 1A. ***Risk Factors***

Commercial Operations

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

Market prices for power, generation capacity, ancillary services, natural gas and fuel oil are unpredictable and 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 and natural gas 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 power plants, expansion of existing power plants or additional transmission capacity;
- changes in power transmission or fuel transportation capacity constraints or inefficiencies;
- power supply disruptions, including power plant outages and transmission disruptions;
- Heat Rate risk;
- weather conditions;
- quarterly and seasonal fluctuations;
- risk associated with declining coal prices;
- 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 or new technologies for the production of power;
- federal and state regulations and actions of the ISOs;
- federal and state power, market and environmental regulation and legislation, including mandating an RPS or creating financial incentives, each resulting in new renewable energy generation capacity creating oversupply;

- changes in prices related to RECs; and
- changes in capacity prices and capacity markets.

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

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, Regional Transmission Organizations and other market regulators that may impair our ability to recover our costs and limit our return on our capital investments;
- regulations promulgated by the FERC and the CFTC;
- some of our competitors (mainly utilities) receive entitlement-guaranteed rates of return on their capital investments, with returns that exceed market returns and may impact our ability to sell our power at economical rates;
- structure and operating characteristics of our capacity markets such as our PJM capacity auctions and our NYISO markets; and
- regulations and market rules related to our RECs.

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 economically 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 under U.S. GAAP, which requires us to record all derivatives on the balance sheet at fair value unless they qualify for, and we elect, the normal purchase normal sale exemption. Changes in the fair value resulting from fluctuations in the underlying commodity prices are immediately recognized in earnings, unless the derivative qualifies for, and is designated as a hedge, and receives cash flow hedge accounting treatment. Commodity price movements could create financial gains or 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, or for economic hedges that currently qualify for cash flow hedge accounting treatment; we may lose cash flow hedge accounting treatment in the future if the forecasted transactions are no longer considered probable of occurring. Additionally, many of our commodity hedge accounting contracts do not currently receive hedge accounting treatment and we may voluntarily decide to discontinue cash flow hedge accounting treatment in the future. As a result, we are unable to accurately predict the impact that our risk management decisions may have on our quarterly and annual financial results.

The use of hedging agreements may not work as planned or fully protect us and 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 may be required to post significant amounts of cash collateral or other credit support to our counterparties and we give up the opportunity to sell power at higher prices if spot prices are higher in the future. 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 financial condition, results of operations and cash flows.

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 financial condition, results of operations and cash flows may be diminished based upon adverse movement in commodity prices.

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

Our customer and supplier counterparties may experience deteriorating credit. These conditions could cause counterparties in the natural gas and power markets, particularly in the energy commodity 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 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 financial condition, results of operations and cash flows.

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 independent power producers. 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 in the power trading markets, putting downward pressure on prices.

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.

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 as merchant energy. 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. Power plants without long-term PPAs involve risk and uncertainty in forecasting future demand load for merchant sales because they are exposed to market fluctuations for some or all of their generating capacity and output. A significant under- or over-estimation of load requirements may increase our operating costs. 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. We are at risk of loss of margins to the extent that these contracts expire or are terminated and we are unable to replace them on comparable terms. Additionally, our PPAs contain termination provisions standard to contracts in our industry such as negligence, performance default or prolonged events of force majeure.

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

To the extent that an economic downturn returns and affects the markets in which we operate, demand for power and power prices may be depressed, and our revenues and operating cash flows could be negatively impacted. In addition, challenges affecting the economy could cause our customers, counterparties, vendors and service providers to experience deteriorating credit and serious cash flow problems. As a result, these conditions could cause counterparties in the natural gas and power markets, particularly in the energy commodity derivative markets that we rely on for our hedging activities, to be unable to perform under existing contracts, or 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.

Power Operations

Our power generating operations performance involves significant risks and hazards and 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 unplanned outages, including extensions of scheduled outages due to equipment breakdowns, failures or other problems and are an inherent risk of our business. Unplanned outages typically can result in lost revenues, increase our maintenance expenses and may reduce our profitability, which could have a material adverse effect on our financial condition, results of operations and cash flows.

In addition, an unplanned outage 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 and we could incur costs to cover our hedges. 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.

We may be subject to future claims, litigation and enforcement.

Our power generating operations are inherently hazardous and may lead to catastrophic events, including loss of life, personal injury and destruction of property, and subject us to litigation. Natural gas is highly explosive and power generation involves hazardous activities, including acquiring, transporting and delivering fuel, operating large pieces of rotating equipment and delivering power to transmission and distribution systems. These and other hazards can cause severe damage to and destruction of property, plant and equipment and suspension of operations. In the worst circumstances, catastrophic events can cause significant personal injury or loss of life. Further, the occurrence of any one of these events may result in us being named as a defendant in lawsuits asserting claims for substantial damages. We maintain an amount of insurance protection that we consider adequate; however, we cannot provide any assurance that the insurance will be sufficient or effective under all circumstances and against all hazards or liabilities to which we are subject.

Additionally, we are party to various litigation matters, including regulatory and administrative proceedings arising out of the normal course of business. We review our litigation activities and determine if an unfavorable outcome to us is considered "remote," "reasonably possible" or "probable" as defined by U.S. GAAP. Where we have determined an unfavorable outcome is probable and is reasonably estimable, we have accrued for potential litigation losses. A successful claim against us that is not fully insured could be material. As a result, we give no assurance that such litigation matters would, individually or in the aggregate, not have a material adverse effect on our financial position, results of operations or cash flows. See also Note 15 of the Notes to Consolidated Financial Statements for a description of our more significant litigation matters.

We rely on power transmission and fuel 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 by our power plants and the distribution of natural gas fuel or fuel oil 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 power project development and construction activities involve risk and may not be successful.

The development and construction 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 and construction activities continue or expand, we may be unsuccessful on a timely and profitable basis. Although we may attempt to minimize the financial risks of these activities 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. The process for obtaining governmental permits and approvals is complicated and lengthy, often taking more than one year, and is subject to significant uncertainties. 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 resulting in potential impairments.

We may be unable to obtain an adequate supply of fuel in the future.

We obtain substantially all of our physical natural gas and fuel oil supply from third parties pursuant to arrangements that vary in term, pricing structure, firmness and delivery flexibility. Our physical natural gas and fuel oil supply arrangements must be coordinated with transportation agreements, balancing agreements, storage services, financial hedging transactions and other contracts so that the natural gas and fuel oil 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 natural gas transportation.

While adequate supplies of natural gas and fuel oil 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 fuel oil 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 and fuel oil 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 and fuel oil 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 and fuel oil or availability of natural gas and fuel oil services (e.g. storage) may be insufficient or available only at prices that are not acceptable to us;
- natural gas and fuel oil quality variation may adversely affect our power plant operations;
- our natural gas and fuel oil operations capability may be compromised due to various events such as natural disaster, loss of key personnel or loss of critical infrastructure;
- fuel supplies diverted to residential heating for humanitarian reasons; and
- any other reasons.

Our power plants and construction projects are subject to impairments.

If we were to experience a significant reduction in our expected revenues and operating cash flows for an extended period of time from a prolonged economic downturn or from advances or changes in technologies, we could experience future impairments of our power plant assets as a result. 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 financial condition, results of operations and cash flows.

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.

Significant events beyond our control, such as natural disasters or acts of terrorism, could damage our power plants or our corporate offices and may impact us in unpredictable ways.

Certain of our geothermal and natural gas-fired power plants, 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. Such events could damage or shut down our power plants, power transmission or the fuel supply facilities upon which our generation business is dependent. 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.

In addition to physical damage to our power plants, the risk of future terrorist activity could result in adverse changes in the insurance markets and disruptions in the power and fuel markets. These events could also adversely affect the U.S. economy, create instability in the financial markets and, as a result, have an adverse effect on our ability to access capital on terms and conditions acceptable to us.

We depend on our management and employees.

Our success is largely dependent on the skills, experience and efforts of our people. 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.

Some of our employees are represented by collective bargaining agreements.

We have 150 employees represented by collective bargaining agreements; however, the amount of employees subject to collective bargaining agreements only represents a small percentage (approximately 7%) of our employee base. In the event that our union employees participate in a strike, work stoppage or engage in other forms of labor disruption, we would be responsible for procuring replacement labor and could experience reduced power generation or outages.

We depend on computer and telecommunications systems we do not own or control and failures in our systems or cyber security attacks could significantly disrupt our business operations.

We have entered into agreements with third parties for hardware, software, telecommunications and other information technology 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. It is possible we could incur interruptions from cyber security attacks, computer viruses or malware. We believe that we have positive relations with our related vendors and maintain adequate anti-virus and malware software and controls; however, any interruptions to our arrangements with third parties, to our computing and communications infrastructure, or our information systems could significantly disrupt our business operations.

Capital Resources; Liquidity

We have substantial liquidity needs and could face liquidity pressure.

As of December 31, 2011, our consolidated debt outstanding was $10.4 billion, of which approximately $5.9 billion was outstanding under our First Lien Notes. In addition we had $763 million issued in letters of credit and our pro rata share of unconsolidated subsidiary debt was approximately $231 million. Although we have significantly extended our maturities during 2011 and 2010, 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, to meet margin requirements 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 in "— Commercial Operations" above. Although we are permitted to enter into new project financing credit facilities to fund our development and construction activities, 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 activities by reducing the number of counterparties with whom we can transact as well as the volume and type of those transactions.

The soundness of financial institutions could adversely affect us.

We have exposure to many different financial institutions and counterparties including those under our First Lien Notes, Term Loan, New Term Loan and Corporate Revolving 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.

We may be unable to obtain additional financing or access the credit and capital markets in the future at prices that are beneficial to us or at all.

If our available cash, including future cash flows generated from operations, is not sufficient in the near term to finance our operations, post collateral or satisfy our obligations as they become due, we may need to access the capital and credit markets. Our ability to arrange financing (including any extension or refinancing) and the cost of the financing is dependent upon numerous factors, including general economic and capital market conditions. Market disruptions such as those experienced in the U.S. and abroad in recent years, may increase our cost of borrowing or adversely affect our ability to access capital. 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. Other factors include:

- low credit ratings may prevent us from obtaining any material amount of additional debt financing;
- conditions in energy commodity 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.

Certain European financial institutions that are lenders to us under debt agreements or counterparties under derivative contracts may become insolvent or unable to perform under their financial commitments to us.

The Russell City Energy Center and Los Esteros Critical Energy Facility are under construction and have debt agreements in place to fund the construction of these facilities which convert to term loans once the power plants become operational. Some of the lenders under these debt agreements are financial institutions domiciled in European countries that are currently experiencing stressed economic and financial conditions. We are also exposed, to a lesser extent, to some of these stressed European financial institutions in the form of outstanding letters of credit and interest rate swap contracts. Should these financial institutions become insolvent or otherwise be unable to provide funding or perform in accordance with their financial commitments under these debt agreements or derivative contracts, we could be required to provide funding from our cash and cash equivalents or record losses.

Our First Lien Notes, Corporate Revolving Facility, Term Loan, New Term Loan and CCFC Notes, and our other debt instruments impose restrictions on us and any failure to comply with these restrictions could have a material adverse effect on our liquidity and our operations.

The restrictions under our First Lien Notes, Corporate Revolving Facility, Term Loan, New Term Loan and CCFC Notes and other debt instruments could adversely affect us by limiting our ability to plan for or react to market conditions or to meet our capital needs and, if we were unable to comply with these restrictions, could result in an event of default under these debt instruments. 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 or guarantee additional first lien indebtedness up to certain consolidated net tangible asset ratios;
- enter into certain types of commodity hedge agreements that can be secured by first lien collateral;
- enter into sale and leaseback transactions;
- make certain investments;
- create or incur liens;
- consolidate or merge with or transfer all or substantially all of our assets to another entity, or allow substantially all of our subsidiaries to do so;
- lease, transfer or sell assets and use proceeds of permitted asset leases, transfers or sales;
- engage in certain business activities; and
- enter into certain transactions with our affiliates.

Our First Lien Notes, Corporate Revolving Facility, Term Loan, New Term Loan and CCFC Notes and our other debt instruments contain events of default customary for financings of their 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 and are unable to obtain a waiver or amendment, or a default exists and is continuing under such debt, the lenders or the holders or trustee of the First Lien Notes, as applicable, could give notice and declare outstanding borrowings and other obligations under such debt 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 our First Lien Notes, Corporate Revolving Facility, Term Loan, New Term Loan and CCFC Notes and our other debt instruments, or if we fail to generate sufficient cash flows from operations, or if it becomes necessary to obtain such waivers, amendments or alternative financing, it could adversely impact our financial condition, results of operations and cash flows.

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 may adversely impact 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 such 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.

Many of our collateral agreements require that letters of credit posted as collateral must be issued by a financial institution with a minimum credit rating of "A". Currently the financial institutions that issue letters of credit under our Corporate Revolving Facility and other letter of credit facilities meet or exceed the minimum credit rating criteria. However, if one or more of the these financial institutions is no longer able to meet the minimum credit rating criteria, then we could be required to post collateral funding from our cash and cash equivalents which could negatively impact our liquidity.

Additionally, changes in market regulations can increase the use of credit support and collateral. The potential impact of the Dodd-Frank Act is uncertain, but it is possible that future regulations, when finalized, under the Dodd-Frank Act could directly or indirectly result in increased credit support and collateral requirements.

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, 2011, we had $763 million issued in letters of credit under our Corporate Revolving Facility and other facilities, with $560 million remaining available for borrowing or for letter of credit support under our Corporate Revolving Facility. 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 Corporate Revolving Facility with the assets previously subject to liens under our First Lien 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, post collateral and finance our ongoing operations. 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, which could increase our debt and may be structurally senior to other debt such as our First Lien Notes, Corporate Revolving Facility, Term Loan and New Term Loan.

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 preferred equity would be added to our current consolidated debt levels and would likely be structurally senior to our debt, which could also intensify the risks associated with our already existing leverage.

Our First Lien Notes, Corporate Revolving Facility, Term Loan and New Term Loan are 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, 2011, our subsidiaries had approximately $1.0 billion in debt from our CCFC subsidiary and approximately $1.7 billion in secured project financing from other subsidiaries, which are effectively senior to our First Lien Notes, Corporate Revolving Facility, Term Loan and New Term Loan. We may incur additional project financing indebtedness in the future, which will be effectively senior to our other secured and unsecured debt.

Governmental Regulation

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 policymakers have been considering imposing a national RPS on retail power providers. California already has an RPS in effect and in 2011 signed into law legislation requiring implementation of a 33% RPS by 2020. 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.

Increased legislation for the construction of power plants, such as those passed by the New Jersey and Maryland state senates could adversely impact our competitive position and business.

Recently, certain states in the PJM market region have taken actions that could impact the PJM capacity market. In New Jersey, legislation enacted in 2011 required the New Jersey Board of Public Utilities ("BPU") to issue a request for proposals ("RFP") for new generation. Market participants and others were concerned that awarding long-term contracts could impact the clearing prices of future PJM capacity auctions. The BPU has also initiated a proceeding and held hearings to investigate whether there is a need for New Jersey to pursue additional generation capacity beyond the 2,000 MW already contracted for pursuant to the legislation. Meanwhile, in response to a filing by PJM that was intended in part to address the negative implications from these state actions by revising the Minimum Offer Price Rule ("MOPR") in its tariff, FERC issued an order on April 12, 2011 approving PJM's MOPR tariff changes. Also, on February 9, 2011, we joined a group of generators and utilities in filing a complaint in federal district court challenging the constitutionality of the New Jersey legislation. The court proceeding is continuing.

On September 29, 2011, the Maryland Public Service Commission ("MPSC") issued a "Notice of Approval of Request for Proposals for New Generation to be Issued by Maryland Electric Distribution Companies." The Notice required the state's IOUs to issue RFPs for up to 1,500 MW of capacity. The Notice specifies that proposals must be for new natural gas-fired capacity capable of delivery into the PJM Southwest Mid-Atlantic Area Council delivery area. The MPSC held a hearing on January 31, 2012 to determine whether new capacity is required, but it has not issued a final order in this proceeding.

Increased oversight and investigation by the CFTC relating to derivative transactions, as well as certain financial institutions, could have an adverse impact on our ability to hedge risks associated with our business.

The CFTC has regulatory oversight of the futures markets, including trading on NYMEX for energy, and licensed futures professionals such as 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. We also expect the CFTC's future powers and oversight to be increased by the Dodd-Frank Act (discussed below).

The unknown impact from the Dodd-Frank Act as well as the rules to be promulgated under it could have an adverse impact on our ability to hedge risks associated with our business, require the implementation of additional policies and require us to incur administrative compliance costs.

Title VII of the Dodd-Frank Act addresses regulatory reform of the OTC derivatives market in the U.S. and significantly changes the regulatory framework of this market. Currently, the effective date for the CFTC to implement all final regulations related to Title VII is July 16, 2012. Certain Title VII regulations have been finalized, however, other key regulations have not been finalized as of this time. Until all of these regulations have been finalized, the extent to which the provisions of Title VII might affect our derivatives activities is unknown. A number of features in the legislation may impact our existing business. One of these is the requirement for central clearing of many OTC derivatives transactions with clearing organizations. This requirement is subject to an end-user exception. Whereas our OTC transactions have traditionally been negotiated on a bilateral basis, including the collateral arrangements thereunder, they now may be subject to the collateral and margining procedures of the clearing organization. The CFTC is also finalizing the regulation which will guide us in determining if we qualify as a commercial end-user under the regulation. If we do not qualify as a commercial end-user, it is highly likely that we will be required to register as a dealer of commodities with the CFTC, and we will be required to perform additional activities within our transaction processes to comply with the regulations; however, our compliance activities will not have a material adverse effect on our financial position or results of operations. Other features of the Dodd-Frank Act which will have an impact on our derivatives activities include trade reporting, position limits and trade execution. The effect of the Dodd-Frank Act on traditional dealers and market-makers as well as the consequential effect on or loss of market liquidity and, hence, pricing is uncertain; however, we expect to be able to continue to participate in financial markets for our derivative transactions.

In addition to legislation and rulemaking provisions related to derivative transactions, the Dodd-Frank Act contains a variety of provisions designed to regulate financial markets. Further, many aspects of the Dodd-Frank Act are subject to rulemaking that will take effect over several years, thus making it difficult to assess its impact on us at this time. We expect to successfully implement any new applicable legislative and regulatory requirements and may incur additional costs associated with our compliance with the new regulations and anticipated additional reporting and disclosure obligations.

Changes in the regulation of the power markets in which we operate could negatively impact us.

We have a significant presence in the major competitive power markets for California, Texas and the Mid-Atlantic region of the U.S. While these markets are largely de-regulated, they continue to evolve. Existing regulations within the markets in which we operate may be revised or reinterpreted and new laws or regulations may be issued. We cannot predict the future development of regulation or legislation nor the ultimate effect such changes in these markets could have on our business; however, we could be negatively impacted.

Existing and future anticipated GHG/Carbon and other air emissions regulations could cause us to incur significant costs and adversely affect our operations generally or in a particular quarter when such costs are incurred.

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 implementing plans for AB 32 which places a statewide cap on GHG emissions and requires the state to return to 1990 emission levels by 2020. In December 2010, CARB adopted a regulation establishing a GHG cap-and trade program which takes effect in 2012 for electric utilities and other "major industrial sources," and in 2015 for certain other GHG sources.

In 2011 the EPA finalized regulations governing GHG emissions from major sources as well as emissions of criteria and hazardous air pollutants from the electric generation sector. We continue to monitor and actively participate in EPA initiatives where we anticipate an impact on our business.

Further, as a result of air regulations recently enacted in New Jersey, certain of our generation assets acquired in the Conectiv Acquisition may need additional NO_X controls to continue operating beyond 2015, which may result in additional controls costs to us. We are currently evaluating the cost to comply with these air regulations and are uncertain of the impact to our financial position or results of operations.

We are subject to other 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 the appropriate foreign, federal, state and local governmental agencies, as well as compliance with numerous environmental laws and regulations of federal, state and local authorities. 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.

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. 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, could have a material negative impact on our financial condition, results of operations and cash flows.

Risks Relating to Our Common Stock

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

As of December 31, 2011, three current 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 5% or more of the shares of our common stock. These shareholders, who together beneficially owned approximately 43% of our common stock at December 31, 2011, 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 significant influence over the election of our entire Board of Directors and significant influence over 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, the ability of our other shareholders to influence us through voting of their 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 one of the three groups of these shareholders, which permits them to sell a large portion of their shares of common stock without being subject to the "trickle out" or other restrictions of Rule 144 under the Securities Act. There were no registered sales during 2011 by shareholders who held more than 5% of our common stock. Sales by any of the three shareholders of all or a substantial portion of their shares within a short period of time, could adversely affect the market price of our common stock or could further concentrate holdings of our common stock in the remaining two shareholders who hold more than 5% of our common stock.

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

Under federal income tax law, our NOL carryforwards can be utilized to reduce future taxable income subject to certain limitations, including if we were to undergo an ownership change as defined by Section 382 of 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 our Plan of Reorganization. However, this ownership change and resulting annual limitations are not expected to result in the expiration of our NOL carryforwards if we are able to generate sufficient future taxable income within the carryforward periods. If a subsequent ownership change were to occur as a result of future transactions in our stock, accompanied by a significant reduction in our market value immediately prior to the ownership change, our ability to utilize the NOL carryforwards may be significantly limited.

To manage the risk of significant limitations on our ability to utilize our tax NOL carryforwards, our amended and restated certificate of incorporation requires our Board of Directors to meet to determine whether to impose certain transfer restrictions on our common stock if, prior to February 1, 2013, our Market Capitalization declines by at least 35% from our Emergence Date Market Capitalization of approximately $8.6 billion (in each case, as defined in and calculated pursuant to our amended and restated certificate of incorporation) and at least 25 percentage points of shift in ownership has occurred with respect to our equity for purposes of Section 382 of the IRC. We believe as of the filing of this Report, neither circumstance was met. Accordingly, the transfer restrictions have not been put in place by our Board of Directors; however, if both of the foregoing events were to occur together and our Board of Directors was to elect to impose them, they could become operative in the future. 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. This facility is leased until 2020. We also have regional offices in Dublin, California and Wilmington, Delaware, an engineering, construction and maintenance services office in Pasadena, Texas and government affairs offices in Washington D.C., Sacramento, California and Austin, Texas.

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 15 of the Notes to Consolidated Financial Statements for a description of our legal proceedings.

Item 4. ***(Removed and Reserved)***

PART II

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

Market Information and Stockholder Matters

Calpine Corporation common stock is traded on the NYSE under the symbol "CPN". The following table sets forth the high and low bid prices for our common stock for each quarter of the years 2011 and 2010, as reported on the NYSE.

	High	Low
2011		
First Quarter	$ 16.25	$ 13.42
Second Quarter	17.10	15.00
Third Quarter	17.08	12.70
Fourth Quarter	16.68	12.79
2010		
First Quarter	$ 12.42	$ 10.71
Second Quarter	14.27	10.95
Third Quarter	14.13	12.20
Fourth Quarter	13.93	11.88

As of December 31, 2011, there were 168 stockholders of record of our common stock.

To manage the risk of significant limitations on our ability to utilize our tax NOL carryforwards, our amended and restated certificate of incorporation requires our Board of Directors to meet to determine whether to impose certain transfer restrictions on our common stock if, prior to February 1, 2013, our Market Capitalization declines by at least 35% from our Emergence Date Market Capitalization of approximately $8.6 billion (in each case, as defined in and calculated pursuant to our amended and restated certificate of incorporation) and at least 25 percentage points of shift in ownership has occurred with respect to our equity for purposes of Section 382 of the Internal Revenue Code. We believe as of the filing of this Report, neither circumstance was met. Accordingly, the transfer restrictions have not been put in place by our Board of Directors; however, if both of the foregoing events were to occur together and our Board of Directors was to elect to impose them, they could become operative in the future. 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.

Should our Board of Directors elect to impose these restrictions, it will have the authority and discretion to determine and establish the definitive terms of the transfer restrictions, provided that the transfer restrictions apply to purchases by owners of 5% or more of our common stock, including any owners who would become owners of 5% or more of our common stock via such purchase. The transfer restrictions will not apply to the disposition of shares provided they are not purchased by a 5% or more owner. If these transfer restrictions are imposed, any increase in the value of our common stock shall not result in the lapse of the transfer restrictions unless the increase in value of our common stock (determined on a weighted average 30-day trading period) shall be at least 10% greater than the trigger price. Our Board of Directors' ability to impose transfer restrictions will terminate on the fifth anniversary of our Emergence Date; however, any transfer restrictions imposed prior to such fifth anniversary will remain in effect until one of the trigger provisions is no longer satisfied.

We have never paid cash dividends on our common stock. Future cash dividends, if any, will be at the discretion of our Board of Directors and will depend upon, among other things, our future operations and earnings, capital requirements, general financial condition, contractual and financing restrictions and such other factors as our Board of Directors may deem relevant. 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.

Repurchase of Equity Securities - The table below sets forth information regarding purchases of our common stock on a monthly basis during the fourth quarter of fiscal 2011. On August 23, 2011, we announced that our Board of Directors had authorized the repurchase of up to $300 million in shares of our common stock. The announced share repurchase program did not specify an expiration date. The repurchases may be commenced or suspended from time to time without prior notice. Through the filing of this Report, a total of 8,524,576 shares of our outstanding common stock have been repurchased under this program for approximately $124 million at an average price paid of $14.60 per share. The shares repurchased under our share repurchase program were purchased in open market transactions and are held as treasury stock.

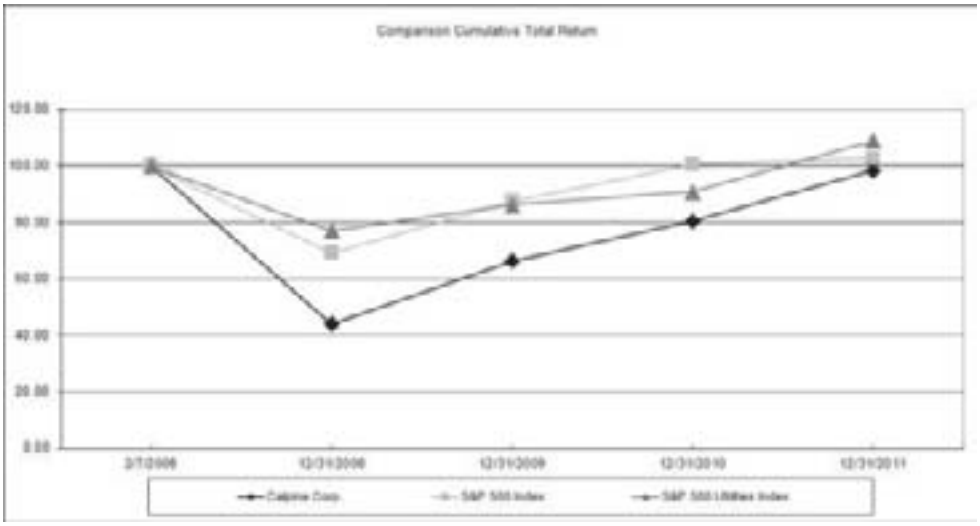
Upon vesting of restricted stock awarded by us to employees, we withhold shares to cover employees' tax withholding obligations, other than for employees who have chosen to make tax withholding payments in cash. Included in the table below, during the fourth quarter of 2011, we withheld a total of 4,090 shares in the indicated months that are included in total number of shares purchased.

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 Dollar Value of Shares That May Yet Be Purchased Under the Plans or Programs (in millions)
October	1,560,233	$ 13.55	1,558,256	$ 271
November	3,955,218	$ 14.89	3,953,576	$ 212
December	2,061,046	$ 15.00	2,060,575	$ 181
Total	7,576,497		7,572,407	

Stock Performance Graph

The performance graph below compares cumulative return on our common stock for the period February 7, 2008 through December 31, 2011, with the cumulative return of Standard & Poor's 500 Index (S&P 500) and the S&P 500 Utilities 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 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	December 31, 2008	December 31, 2009	December 31, 2010	December 31, 2011
Calpine Corporation	$ 100	$ 43.86	$ 66.27	$ 80.36	$ 98.37
S&P 500 Index	100	69.06	87.33	100.49	102.61
S&P Utilities Index	100	76.98	86.15	90.85	108.94

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Item 6. ***Selected Financial Data***

SELECTED CONSOLIDATED FINANCIAL DATA

	Years Ended December 31,				
	2011	2010	2009	2008	2007
	(in millions, except earnings (loss) per share)				
Statement of Operations data:					
Operating revenues	$ 6,800	$ 6,545	$ 6,463	$ 9,837	$ 7,869
Income (loss) before discontinued operations attributable to Calpine[1]	$ (190)	$ (162)	$ 114	$ (26)	$ 2,666
Discontinued operations, net of tax expense, attributable to Calpine	—	193	35	36	27
Net income (loss) attributable to Calpine[1]	$ (190)	$ 31	$ 149	$ 10	$ 2,693
Basic earnings (loss) per common share[2]:					
Income (loss) before discontinued operations attributable to Calpine[1]	$ (0.39)	$ (0.33)	$ 0.24	$ (0.05)	$ 5.56
Discontinued operations, net of tax expense, attributable to Calpine	—	0.39	0.07	0.07	0.06
Net income (loss) per common share attributable to Calpine[1]	$ (0.39)	$ 0.06	$ 0.31	$ 0.02	$ 5.62
Diluted earnings (loss) per common share[2]:					
Income (loss) before discontinued operations attributable to Calpine[1]	$ (0.39)	$ (0.33)	$ 0.24	$ (0.05)	$ 5.56
Discontinued operations, net of tax expense, attributable to Calpine	—	0.39	0.07	0.07	0.06
Net income (loss) per common share attributable to Calpine[1]	$ (0.39)	$ 0.06	$ 0.31	$ 0.02	$ 5.62
Balance Sheet data:					
Total assets	$ 17,371	$ 17,256	$ 16,650	$ 20,738	$ 19,050
Short-term debt and capital lease obligations	104	152	463	716	1,710
Long-term debt and capital lease obligations	10,321	10,104	8,996	9,756	9,946
Liabilities subject to compromise[3]	—	—	—	—	8,788

(1) 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 earnings per share information for the year ended December 31, 2007 is presented, it is not comparable to the information presented for the years ended December 31, 2011, 2010, 2009 and 2008, due to the changes in our capital structure on the Effective Date, which also included termination of all outstanding convertible securities.

(3) In connection with our emergence from Chapter 11, liabilities subject to compromise were either paid or reclassified to equity on the Effective Date.

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 the largest independent wholesale power generation company in the U.S. measured by power produced. We own and operate primarily natural gas-fired and geothermal power plants in North America and have a significant presence in major competitive wholesale power markets in California, Texas and the Mid-Atlantic region of the U.S. We sell wholesale power, steam, capacity, renewable energy credits and ancillary services to our customers, which include utilities, independent electric system operators, industrial and agricultural companies, retail power providers, municipalities, power marketers and others. We have invested in clean power generation to become a recognized leader in developing, constructing, owning and operating an environmentally responsible portfolio of power plants. We purchase natural gas and fuel oil as fuel for our power plants, engage in related natural gas transportation and storage transactions, and we purchase electric transmission rights to deliver power to our customers. We also enter into natural gas and power physical and financial contracts to hedge certain business risks and optimize our portfolio of power plants. Our goal is to be recognized as the premier independent power company in the U.S. as measured by our employees, customers, regulators, shareholders and communities in which our facilities are located. We seek to achieve sustainable growth through financially disciplined power plant development, construction, acquisition, operation and ownership. 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 agreements within the guidelines of our Risk Management Policy.

We assess our business on a regional basis due to the impact on our financial performance of the differing characteristics of these regions, particularly with respect to competition, regulation and other factors impacting supply and demand. Our reportable segments are West (including geothermal), Texas, North (including Canada) and Southeast.

Our portfolio, including partnership interests, includes 93 power plants, including 2 under construction, located throughout 20 states in the U.S. and Canada, with an aggregate generation capacity of 28,155 MW and 584 MW under construction. Our generation capacity includes 77 natural gas-fired power plants, 15 geothermal plants and 1 photovoltaic solar plant consisting of approximately 725 MW of baseload capacity from our Geysers Assets and 4,561 MW of baseload capacity from our cogeneration power plants, 16,393 MW of intermediate load capacity from our combined-cycle combustion turbines and 6,476 MW of peaking capacity from our simple-cycle combustion turbines and duct-fired capability, which includes approximately 4 MW of capacity from solar, photovoltaic power generation technology located in New Jersey. Our segments have an aggregate generation capacity of 6,919 MW with an additional 584 MW under construction in the West, 7,239 MW in Texas, 7,914 MW in the North and 6,083 MW in the Southeast. Our Geysers Assets, included in our West segment, have generation capacity of approximately 725 MW from 15 operating geothermal power plants, and we have begun expansion efforts to increase our generation capacity at our Geysers Assets.

Current Year Operational Developments

We continue to make significant progress to maintain financially disciplined growth, to enhance shareholder value and to set the foundation for continued growth and success with the following achievements during the year ended December 31, 2011:

- Our York Energy Center, a 565 MW dual fuel, combined-cycle power plant achieved COD on March 2, 2011, and began selling power under a six-year PPA with a third party which commenced on June 1, 2011.
- Construction of our Russell City Energy Center, which closed on construction financing in June 2011, and upgrades at our Los Esteros Critical Energy Facility, which closed on construction financing in August 2011, continue to move forward with expected completion dates in 2013.
- We continue to move forward with our turbine upgrade program. Through December 31, 2011, we have completed the upgrade of ten Siemens and five GE turbines and have agreed to upgrade approximately six additional Siemens and GE turbines (and may upgrade additional turbines in the future). Our turbine upgrade program is expected to

increase our generation capacity in total by approximately 275 MW. This upgrade program began in the fourth quarter of 2009 and is scheduled through 2014. The upgraded turbines have been operating with Heat Rates consistent with expectations.

- We continue to look to expand our production from our Geysers Assets. Beginning in the fourth quarter of 2009, we conducted an exploratory drilling program, which effectively proved the commercial viability of the steam field in the northern part of our Geysers Assets. We have received Conditional Use Permits from Sonoma County and are pursuing the additional required permitting. We are pursuing commercial arrangements which will need to be in place prior to commencing expansion activities. We continue to believe our northern Geysers Assets have potential for development. In the meantime, we have connected certain test wells to our existing power plants to capture incremental production from those wells, while continuing with the permitting process, baseline engineering work and sales efforts for an expansion.
- Throughout 2011, our plant operating personnel achieved the first quartile performance for employee lost time incident rate for fossil fuel electric power generation companies with 1,000 or more employees.
- We produced over 94 billion KWh in 2011.
- Our entire fleet achieved a forced outage factor of 2.5%.
- We achieved 98.4% fleet-wide starting reliability in 2011.
- During 2011, our Turbine Maintenance Group completed 16 major inspections and 15 hot gas path inspections.
- For the past eleven consecutive years, our Geysers Assets have reliably generated approximately 6 million MWh per year and, in 2011, achieved an exceptional availability factor of approximately 98%.

Enhancing Shareholder Value

We continue to make significant progress to maintain financially disciplined growth, to enhance shareholder value through our capital allocation and share repurchases and to set the foundation for continued growth and success. Given our strong cash flow from operations, we are committed to remaining financially disciplined in our capital allocation decisions. The year ended December 31, 2011 was marked by the following accomplishments:

- Our total shareholder return for 2011 was 22.4% (measured by the year over year change in our stock price).
- On August 23, 2011, we announced that our Board of Directors had authorized the repurchase of up to $300 million in shares of our common stock. Through the filing of this Report, a total of 8,524,576 shares of our outstanding common stock have been repurchased under this program for approximately $124 million at an average price paid of $14.60 per share.
- We issued our 2023 First Lien Notes, terminated our First Lien Credit Facility and extended our corporate debt maturities. Together, these changes eliminated the more restrictive of our debt covenants, resulting in increased operational, strategic and financial flexibility in managing our capital resources including the flexibility to reinvest more earnings for organic growth, issue and/or buyback shares of our common stock and incur additional debt, if needed, for acquisitions or development projects. Additionally, we achieved attractive yields and a maturity schedule stretching from 2017 to 2023 with no more than $2.0 billion of corporate debt maturing in any given year.
- We have further continued to reduce our overall cost of debt and simplify our capital structure by refinancing subsidiary level debt with corporate level term loans eliminating the need for subsidiary level reporting and the potential for cash to be temporarily trapped at the subsidiary level. On March 9, 2011, we closed on the $1.3 billion Term Loan and used the net proceeds received, together with operating cash on hand, to fully retire the approximately $1.3 billion NDH Project Debt in accordance with its repayment terms. On June 17, 2011, we repaid approximately $340 million of project debt with the proceeds received from $360 million in borrowings under the New Term Loan.
- On June 24, 2011, we closed on the approximately $845 million Russell City Project Debt to fund the construction of Russell City Energy Center and on August 23, 2011, we closed on the $373 million Los Esteros Project Debt to fund the upgrade of our Los Esteros Critical Energy Facility.
- During the fourth quarter of 2011, the U.S. Bankruptcy Court issued an order dismissing the Chapter 11 cases that remained open against the U.S. Debtors; thus, all matters related to our voluntary petitions for relief under Chapter 11 of the Bankruptcy Code filed in 2005 and 2006 are resolved and closed.

For a further discussion of our significant financing transactions completed in 2011, see "— Liquidity and Capital Resources."

Customer-Oriented Origination Business

We continue to focus on providing products and services that are beneficial to our customers. A summary of certain significant contracts entered into or approved in 2011 is as follows:

Efficient operation of our fleet creates the opportunity to capture Commodity Margin in a cost effective manner. However, unplanned outages during periods when Commodity Margin is positive 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. The lower our operating Heat Rate compared to the Market Heat Rate, the more favorable the impact on our Commodity Margin. Holding all other factors constant, our Commodity Margin increases when we are able to lower our operating Heat Rate compared to the Market Heat Rate and conversely decreases when our operating Heat Rate increases compared to the Market Heat Rate. See also "— The Market for Power — Our Power Markets and Market Fundamentals" in Item 1. of this Report for additional information on how these factors impact our Commodity Margin.

RESULTS OF OPERATIONS FOR THE YEARS ENDED DECEMBER 31, 2011 AND 2010

Below are our results of operations for the year ended December 31, 2011, as compared to the same period in 2010 (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.

	2011	2010	Change	% Change
Operating revenues:				
Commodity revenue	$ 6,761	$ 6,578	$ 183	3
Mark-to-market activity[1]	35	(61)	96	#
Other[2]	4	28	(24)	(86)
Operating revenues	6,800	6,545	255	4
Operating expenses:				
Fuel and purchased energy expense:				
Commodity expense	4,289	4,178	(111)	(3)
Mark-to-market activity[1]	60	(204)	(264)	#
Fuel and purchased energy expense	4,349	3,974	(375)	(9)
Plant operating expense	904	868	(36)	(4)
Depreciation and amortization expense	550	570	20	4
Sales, general and other administrative expense	131	151	20	13
Other operating expenses[3]	87	100	13	13
Total operating expenses	6,021	5,663	(358)	(6)
Impairment losses	—	116	116	#
(Gain) on sale of assets, net	—	(119)	(119)	#
(Income) from unconsolidated investments in power plants	(21)	(16)	5	31
Income from operations	800	901	(101)	(11)
Interest expense	760	813	53	7
Loss on interest rate derivatives	145	223	78	35
Interest (income)	(9)	(11)	(2)	(18)
Debt extinguishment costs	94	91	(3)	(3)
Other (income) expense, net	21	15	(6)	(40)
Loss before income taxes and discontinued operations	(211)	(230)	19	8
Income tax benefit	(22)	(68)	(46)	(68)
Loss before discontinued operations	(189)	(162)	(27)	(17)
Discontinued operations, net of tax expense	—	193	(193)	#
Net income (loss)	(189)	31	(220)	#
Net income attributable to the noncontrolling interest	(1)	—	(1)	—
Net income (loss) attributable to Calpine	$ (190)	$ 31	$ (221)	#

	2011	2010	Change	% Change
Operating Performance Metrics:				
MWh generated (in thousands)[4]	90,875	88,323	2,552	3
Average availability	90.1%	90.4%	(0.3)%	—
Average total MW in operation[4]	27,234	24,993	2,241	9
Average capacity factor, excluding peakers	44.3%	46.0%	(1.7)%	(4)
Steam Adjusted Heat Rate	7,412	7,338	(74)	(1)

Variance of 100% or greater

(1) Amount represents the unrealized portion of our mark-to-market activity.

(2) Includes $8 million of contract amortization for the year ended December 31, 2011, related to a contract that became effective in 2011.

(3) Includes $10 million and $9 million of RGGI compliance and other environmental costs for the years ended December 31, 2011 and 2010, respectively, which are components of Commodity Margin.

(4) Represents generation and capacity from power plants that we both consolidate and operate. See "— Description of Our Power Plants – Table of Operating Power Plants and Projects Under Construction" for our total equity generation and capacities.

We evaluate our commodity revenue and commodity expense on a collective basis because the price of power and natural gas tend to move together as the price for power is generally determined by the variable operating cost of the next marginal generator to be dispatched to meet demand. The spread between our commodity revenue and commodity expense represents a significant portion of our Commodity Margin. Our financial performance is correlated to how we maximize our Commodity Margin through management of our portfolio of power plants, as well as our hedging and optimization activities. See additional segment discussion in "Commodity Margin and Adjusted EBITDA."

Commodity revenue, net of commodity expense, increased $72 million for the year ended December 31, 2011, compared to the year ended December 31, 2010, primarily due to:

- an increase in the North primarily due to the Conectiv Acquisition which closed on July 1, 2010, and our York Energy Center which achieved COD in March 2011; partially offset by
- the negative impact in Texas of unplanned outages at some of our power plants caused by an extreme cold weather event in early February 2011, which required us to purchase physical replacement power at prices substantially above our hedged price;
- despite a higher contribution from hedges, commodity revenue, net of commodity expense decreased in the West primarily due to lower Spark Spreads resulting from a significant increase in hydroelectric generation in California in 2011 compared to 2010; and
- a decrease in the Southeast primarily due to the expiration of certain hedge contracts which benefited the year ended December 31, 2010.

Our average total MW in operation increased by 2,241 MW, or 9%, primarily due to the Conectiv Acquisition which closed on July 1, 2010 and our York Energy Center which achieved COD in March 2011 partially offset by the sale of a 25% undivided interest in the assets of our Freestone power plant in December 2010. Generation increased 3% due primarily to higher generation in the North due to the Conectiv Acquisition and our York Energy Center and higher generation in Texas driven by extreme heat and drought conditions during the third quarter of 2011. The increase in generation was partially offset by lower generation in the West resulting from weaker price conditions which also largely contributed to a 4% decrease in our average capacity factor, excluding peakers in 2011 compared to 2010.

Unrealized mark-to-market earnings from hedging our future generation and fuel needs had an unfavorable variance of $168 million primarily driven by the realization of favorable hedge positions in 2011 reported in mark-to-market activity at December 31, 2010, resulting in an unfavorable period over period change partially offset by unrealized gains on fuel and purchased energy positions reported at December 31, 2011.

Other revenue decreased for the year ended December 31, 2011, compared to the year ended December 31, 2010, due primarily to $8 million of amortization expense on intangible contract values related to a contract that became effective in 2011. In addition, there was a decrease in other revenue of $15 million due to an adjustment related to prior periods on a major maintenance contract which resulted in higher revenue recognized in the second quarter of 2010.

Plant operating expense increased by $36 million for the year ended December 31, 2011, compared to the year ended December 31, 2010. Our normal, recurring plant operating expense decreased $32 million and costs related to unscheduled outages decreased $22 million, due largely to insurance recoveries for the year ended December 31, 2011, compared to the year ended December 31, 2010. The increase in plant operating expense was primarily due to an increase of $28 million related to our Mid-Atlantic assets acquired in the Conectiv Acquisition, an increase of $7 million related to our York Energy Center which achieved COD in March 2011, an increase of $41 million in major maintenance expense resulting from our plant outage schedule, an increase

of $6 million in costs from scrap parts related to outages, an increase in costs of $5 million related to our voluntary departure incentive program which was initiated in the second quarter of 2011 and an increase of $3 million in stock-based compensation expense.

Depreciation and amortization expense decreased for the year ended December 31, 2011, compared to the year ended December 31, 2010, primarily resulting from a decrease of $39 million due to rotable parts being fully depreciated for some of our units, a decrease of $17 million related to a revision in the expected settlement dates of the asset retirement obligations of our power plants and a decrease of $5 million due to the sale of a 25% undivided interest in the assets of our Freestone power plant in December 2010. The decrease was partially offset by an increase of $24 million related to our Mid-Atlantic assets acquired in the Conectiv Acquisition, an increase of $6 million related to York Energy Center which achieved COD in March 2011 and an increase of $11 million related to depreciation for assets placed into service during 2011.

Sales, general and other administrative expense decreased for the year ended December 31, 2011, compared to the year ended December 31, 2010, primarily resulting from $26 million in Conectiv acquisition-related costs incurred during the year ended December 31, 2010. The decrease was partially offset by $10 million due to the reversal of a bad debt allowance in the first quarter of 2010 as a result of Lyondell Chemical Co.'s emergence from Chapter 11 bankruptcy and the bankruptcy court's acceptance of our claim in the first quarter of 2010.

Other operating expenses decreased for the year ended December 31, 2011, compared to the year ended December 31, 2010, resulting from a decrease of $10 million in operating lease expense due to our purchase from a third party of the entity that held the lease of our South Point power plant in December 2010 and a decrease of $3 million in royalty expense due to lower revenues from our Geysers Assets resulting from lower prices in 2011 compared to 2010.

Impairment losses for the year ended December 31, 2010 consisted of an impairment of approximately $95 million related to South Point (see Note 3 of the Notes to Consolidated Financial Statements for further information related to our acquisition of the South Point lease and subsequent impairment of our South Point assets) and approximately $21 million associated with two development projects that originated prior to our Chapter 11 bankruptcy proceedings. During the third quarter of 2010, we learned the projects would not receive PPAs that would support their continued development and made the determination that continued development was unlikely.

Gain on sale of assets, net consists of a $119 million gain recorded in the fourth quarter of 2010 related to the sale of a 25% undivided interest in the assets of our Freestone power plant. See Note 3 of the Notes to Consolidated Financial Statements for further information.

Income from unconsolidated investments in power plants had a favorable variance for the year ended December 31, 2011, compared to the year ended December 31, 2010, primarily due to a $4 million period over period increase in operating income for Greenfield LP related to mechanical issues which impacted plant performance during the third quarter of 2010.

Interest expense decreased for the year ended December 31, 2011, compared to the year ended December 31, 2010, primarily due to a $45 million favorable change in unrealized mark-to-market activity related to the interest rate swaps hedging our variable rate debt that do not qualify for hedge accounting and a decrease of $7 million due to capitalized interest related to project debt for two of our facilities under construction. Also contributing to the favorable period over period change in interest expense was a decrease in our annual effective interest rate on our consolidated debt, excluding the impacts of capitalized interest and unrealized gains (losses) on interest rate swaps, which decreased to 7.6% for the year ended December 31, 2011, from 7.9% for the year ended December 31, 2010.

Loss on interest rate derivatives had a favorable change of $78 million for the year ended December 31, 2011, compared to the year ended December 31, 2010, primarily resulting from a period over period decrease of $115 million in historical unrealized losses previously deferred in AOCI and reclassified into income related to interest rate swaps formerly hedging our First Lien Credit Facility term loans. See Note 8 of the Notes to Consolidated Financial Statements for further discussion of our interest rate swaps formerly hedging our First Lien Credit Facility term loans. The favorable change was partially offset by an unfavorable period over period change of approximately $20 million due to realized interest rate swap settlements and changes in fair value subsequent to the reclassification date of the interest rate swaps formerly hedging our First Lien Credit Facility term loans. Also contributing to the unfavorable period over period change was an increase of $17 million resulting from interest rate swap breakage costs related to the repayment of project debt in June 2011.

Debt extinguishment costs for the year ended December 31, 2011, primarily consisted of $74 million associated with the repayment of the NDH Project Debt in March 2011, $19 million associated with the retirement of the First Lien Credit Facility term loans in January 2011 in connection with the issuance of the 2023 First Lien Notes and $5 million related to the write-off of unamortized deferred financing costs related to the repayment of project debt in June 2011. See Note 6 of the Notes to Consolidated Financial Statements for further information regarding the issuance of the 2023 First Lien Notes, the repayment of the NDH Project

Debt and the repayment of other project debt. Debt extinguishment costs for the year ended December 31, 2010, consisted of $61 million associated with the retirement of term loans under the First Lien Credit Facility in May, July and October 2010 in connection with the issuance of the 2019, 2020 and 2021 First Lien Notes and $30 million associated with the acquisition of the Broad River lease which was accounted for as a refinancing of existing debt under U.S. GAAP. See Note 3 of the Notes to Consolidated Financial Statements for further information regarding our acquisition of the Broad River lease.

During the year ended December 31, 2011, we recorded an income tax benefit of $22 million compared to $68 million for the year ended December 31, 2010. The period over period change primarily resulted from an unfavorable variance in income tax expense of $128 million related to the application of intraperiod tax allocation and an increase in various state and foreign jurisdiction income taxes of $19 million for the year ended December 31, 2011, compared to the year ended December 31, 2010. The unfavorable variance in income tax expense was partially offset by a decrease in federal income tax of $101 million due primarily from a one-time $76 million benefit to reduce our valuation allowance due to the election to consolidate the CCFC group with the Calpine group for 2011 for federal income tax reporting purposes and a decrease of $14 million due to the expiration of a statute of limitation related to an uncertain tax position. See Note 10 of the Notes to Consolidated Financial Statements for further discussion of the election to consolidate the CCFC group and the Calpine group for federal tax reporting purposes.

Income from discontinued operations for the year ended December 31, 2010, primarily consisted of $160 million associated with the gain, net of tax, on the sale of our 100% ownership interests in Blue Spruce and Rocky Mountain in December 2010. Also included in the income from discontinued operations for the year ended December 31, 2010, are the results of operations for Blue Spruce and Rocky Mountain. See Note 3 of the Notes to Consolidated Financial Statements for further discussion of our discontinued operations.

RESULTS OF OPERATIONS FOR THE YEARS ENDED DECEMBER 31, 2010 AND 2009

Below are our results of operations for the year ended December 31, 2010, as compared to the same period in 2009 (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.

	2010	2009	Change	% Change
Operating revenues:				
Commodity revenue	$ 6,578	$ 6,362	$ 216	3
Mark-to-market activity[1]	(61)	80	(141)	#
Other	28	21	7	33
Operating revenues	6,545	6,463	82	1
Cost of revenue:				
Fuel and purchased energy expense:				
Commodity expense	4,178	3,896	(282)	(7)
Mark-to-market activity[1]	(204)	1	205	#
Fuel and purchased energy expense	3,974	3,897	(77)	(2)
Plant operating expense	868	868	—	—
Depreciation and amortization expense	570	456	(114)	(25)
Sales, general and other administrative expense	151	174	23	13
Other operating expense[2]	100	101	1	1
Total operating expenses	5,663	5,496	(167)	(3)
Impairment losses	116	4	(112)	#
(Gain) on sale of assets, net	(119)	—	119	—
(Income) from unconsolidated investments in power plants	(16)	(50)	(34)	(68)
Income from operations	901	1,013	(112)	(11)
Interest expense	813	815	2	—
Loss on interest rate derivatives	223	—	(223)	—
Interest (income)	(11)	(16)	(5)	(31)
Debt extinguishment costs	91	76	(15)	(20)
Other (income) expense, net	15	13	(2)	(15)
Income (loss) before income taxes and discontinued operations	(230)	125	(355)	#
Income tax expense (benefit)	(68)	15	83	#
Income (loss) before discontinued operations	(162)	110	(272)	#
Discontinued operations, net of tax expense	193	35	158	#
Net income	31	145	(114)	(79)
Net loss attributable to the noncontrolling interest	—	4	(4)	#
Net income attributable to Calpine	$ 31	$ 149	$ (118)	(79)

	2010	2009	Change	% Change
Operating Performance Metrics:				
MWh generated (in thousands)[3]	88,323	84,376	3,947	5
Average availability	90.4%	92.1%	(1.7)%	(2)
Average total MW in operation[3]	24,993	22,483	2,510	11
Average capacity factor, excluding peakers	46.0%	48.2%	(2.2)%	(5)
Steam Adjusted Heat Rate	7,338	7,264	(74)	(1)

Variance of 100% or greater

(1) Amount represents the unrealized portion of our mark-to-market activity.

(2) Includes $9 million and $5 million of RGGI compliance and other environmental costs for the years ended December 31, 2010 and 2009, respectively, which are components of Commodity Margin.

(3) Represents generation and capacity from power plants that we both consolidate and operate. See "— Description of Our Power Plants – Table of Operating Power Plants and Projects Under Construction" for our total equity generation and capacities.

We evaluate our commodity revenue and commodity expense on a collective basis because the price of power and natural gas tend to move together as the price for power is generally determined by the variable operating cost of the next marginal generator to be dispatched to meet demand. The spread between our commodity revenue and commodity expense represents a significant portion of our Commodity Margin. Our financial performance is correlated to how we maximize our Commodity Margin through management of our portfolio of power plants, as well as our hedging and optimization activities. See additional segment discussion in "Commodity Margin and Adjusted EBITDA."

Commodity revenue, net of commodity expense, decreased $66 million for the year ended December 31, 2010 compared to the year ended December 31, 2009, primarily due to:

- lower average hedge margins in 2010 compared to 2009;
- lower realized Spark Spreads on open positions due to lower Market Heat Rates, primarily in California and Texas, attributable to weaker market conditions resulting from milder weather and increased hydroelectric generation in the West and an increase in installed generation capacity in California and Texas in 2010 compared to 2009; partially offset by
- an increase in the North primarily due to the Conectiv Acquisition which closed on July 1, 2010.

Our average total MW in operation increased by 2,510 MW, or 11%, primarily due to the Conectiv Acquisition and OMEC, which achieved commercial operations in October 2009 and was consolidated on January 1, 2010. Generation increased 5% due primarily to the Conectiv Acquisition and stronger market price conditions in the North partially offset by weaker market price conditions in California and Texas.

Unrealized mark-to-market earnings from hedging our future generation and fuel needs increased by $64 million primarily driven by the impact of lower gas prices on our forward short financial gas position partially offset by losses recognized on our short power Heat Rate swap position held at December 31, 2010.

Other revenue increased for the year ended December 31, 2010 compared to the year ended December 31, 2009, due primarily to $19 million in revenue recognized in 2010 which included a $15 million adjustment related to prior periods on a maintenance contract. This increase was partially offset by a decrease of $8 million related to an operations and maintenance contract that expired in March 2010.

Plant operating expense was unchanged for the year ended December 31, 2010 compared to the year ended December 31, 2009, despite a 2,510 MW increase in our average total MW in operation over the same periods. During 2010 compared to 2009, we experienced a decrease of $28 million in normal, recurring plant operating expense, a decrease of $22 million in costs from scrap parts related to outages, a $16 million decrease in major maintenance resulting from our plant outage schedule and a decrease of $6 million in stock-based compensation expense related to plant personnel costs. The decrease in plant operating expense was offset by an increase related to the Conectiv Acquisition, and OMEC, which achieved commercial operations in October 2009 and was consolidated on January 1, 2010, and a $6 million increase related to costs incurred for unscheduled outages.

Depreciation and amortization expense increased for the year ended December 31, 2010 compared to the year ended December 31, 2009, primarily resulting from an increase of $68 million due to a revision in the estimated useful lives and salvage values of our power plants and related equipment and changing our Geysers Assets depreciation from the units of production method to the straight line method. See Note 4 of the Notes to Consolidated Financial Statements for further information regarding our change in useful lives and salvage values as well as our change from the units of production method to the straight line depreciation method for our Geysers Assets. Also contributing to the increase was $33 million in depreciation and amortization expense related to the Conectiv Acquisition and $15 million related to OMEC which achieved commercial operation in October 2009 and was consolidated on January 1, 2010.

Sales, general and other administrative expense decreased for the year ended December 31, 2010 compared to the year December 31, 2009, due to a $21 million decrease in personnel costs due largely to lower stock-based compensation expense and

temporary labor costs, a $14 million favorable change in our bad debt expense primarily related to a $10 million reversal of our bad debt allowance in the first quarter of 2010 as a result of Lyondell Chemical Co.'s emergence from Chapter 11 bankruptcy and the bankruptcy court's acceptance of our claim and a $13 million decrease in consulting expense. The decrease was partially offset by $26 million in Conectiv acquisition-related costs incurred during the year ended December 31, 2010.

Impairment losses for the year ended December 31, 2010 consisted of an impairment of approximately $95 million related to South Point (see Note 3 of the Notes to Consolidated Financial Statements for further information related to our acquisition of the South Point lease and subsequent impairment of our South Point assets) and approximately $21 million associated with two development projects that originated prior to our Chapter 11 bankruptcy proceedings. During the third quarter of 2010, we learned the projects would not receive PPAs that would support their continued development and made the determination that continued development was unlikely.

Gain on sale of assets, net consists of a $119 million gain recorded in the fourth quarter of 2010 related to the sale of a 25% undivided interest in the assets of our Freestone power plant. See Note 3 of the Notes to Consolidated Financial Statements for further information.

Income from unconsolidated investments in power plants decreased by $34 million for the year ended December 31, 2010 compared to the year ended December 31, 2009, primarily due to the consolidation of OMEC on January 1, 2010. During the year ended December 31, 2009, OMEC recorded income of $32 million which largely consisted of a $28 million gain related to mark-to-market activity from interest rate swap contracts. See Notes 2 and 5 of the Notes to Consolidated Financial Statements for further information regarding our consolidation of OMEC and unconsolidated investments, respectively.

Interest expense decreased for the year ended December 31, 2010 compared to the year ended December 31, 2009, primarily due a decrease of $26 million resulting from the repayment in February 2010 of the notes related to PCF and PCF III, a decrease of $17 million related to the refinancing of our CCFC Old Notes, CCFC Term Loans, and the CCFCP Preferred Shares in 2009 and a decrease in the annualized effective interest rates on our consolidated debt, excluding the impacts of capitalized interest and unrealized gains (losses) on interest rate swaps, which decreased to 7.9% for the year ended December 31, 2010 from 8.0% for the year ended December 31, 2009. The decrease was partially offset by an increase of approximately $52 million in interest expense related to the NDH Project Debt incurred in the second half of 2010 and a $25 million increase related to the consolidation of OMEC on January 1, 2010.

Loss on interest rate derivatives had an unfavorable change of $223 million for the year ended December 31, 2010 due to the reclassification of approximately $206 million in historical unrealized losses previously deferred in AOCI related to interest rate swaps formerly hedging our First Lien Credit Facility and approximately $17 million related to realized swap settlements subsequent to the reclassification date and the changes in fair value subsequent to the de-designation date of the interest rate swaps formerly hedging our First Lien Credit Facility term loans. See Note 8 of the Notes to Consolidated Financial Statements for further discussion of our interest rate swaps formerly hedging our First Lien Credit Facility.

Interest income decreased primarily due to lower average cash balances for the year ended December 31, 2010 compared to the year ended December 31, 2009.

Debt extinguishment costs for the year ended December 31, 2010 consisted of $61 million associated with the retirement of term loans under the First Lien Credit Facility in May, July and October 2010 in connection with the issuance of the 2019, 2020 and 2021 First Lien Notes and $30 million associated with the acquisition of the Broad River lease which was accounted for as a refinancing of existing debt under U.S. GAAP. See Note 3 of the Notes to Consolidated Financial Statements for further information regarding our acquisition of the Broad River lease. Debt extinguishment costs for the year ended December 30, 2009 consisted of $76 million associated with the retirement of the term loans under the First Lien Credit Facility in October 2009, the refinancing of our CCFC Old Notes and CCFC Term Loans in May and June 2009, respectively, and the CCFCP Preferred Shares that were redeemed on or before July 1, 2009.

During the year ended December 31, 2010, we recorded an income tax (benefit) of $(68) million compared to income tax expense of $15 million for the year ended December 31, 2009. The period over period change primarily resulted from a decrease of $129 million related to the application of intraperiod tax allocation partially offset by an increase in federal income tax of $43 million for the CCFC group for the year ended December 31, 2010 compared to the year ended December 31, 2009.

Income from discontinued operations increased for the year ended December 31, 2010 compared to the year ended December 31, 2009, due largely to a $160 million gain, net of tax, on the sale of our 100% ownership interests in Blue Spruce and Rocky Mountain. See Note 3 of the Notes to Consolidated Financial Statements for further discussion of our discontinued operations. Also included in the income from discontinued operations are the results of operations for Blue Spruce and Rocky Mountain.

COMMODITY MARGIN AND ADJUSTED EBITDA

Management's Discussion and Analysis of Financial Condition and Results of Operations includes financial information prepared in accordance with U.S. GAAP, as well as the non-GAAP financial measures, Commodity Margin and Adjusted EBITDA, discussed below, which we use as measures 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 U.S. GAAP.

We use Commodity Margin, a non-GAAP financial measure, to assess our performance by our reportable segments. Commodity Margin includes our power and steam revenues, sales of purchased power and physical natural gas, capacity revenue, REC revenue, sales of surplus emission allowances, transmission revenue and expenses, fuel and purchased energy expense, fuel transportation expense, RGGI compliance and other environmental costs, and cash settlements from our marketing, hedging and optimization activities including natural gas transactions hedging future power sales that are included in mark-to-market activity, but excludes the unrealized portion of our mark-to-market activity and other 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 U.S. GAAP and should be viewed as a supplement to and not a substitute for our results of operations presented in accordance with U.S. GAAP. Commodity Margin does not intend to represent income from operations, the most comparable U.S. GAAP measure, as an indicator of operating performance and is not necessarily comparable to similarly titled measures reported by other companies. See Note 16 of the Notes to Consolidated Financial Statements for a reconciliation of Commodity Margin to income (loss) from operations by segment.

Commodity Margin by Segment for the Years Ended December 31, 2011 and 2010

The following tables show our Commodity Margin and related operating performance metrics by segment for the years ended December 31, 2011 and 2010. In the comparative tables below, favorable variances are shown without brackets while unfavorable variances are shown with brackets. The MWh generated by segment below represents generation from power plants that we both consolidate and operate.

West:	**2011**	**2010**	**Change**	**% Change**
Commodity Margin (in millions)	$ 1,061	$ 1,080	$ (19)	(2)
Commodity Margin per MWh generated	$ 44.54	$ 34.94	$ 9.60	27
MWh generated (in thousands)	23,823	30,909	(7,086)	(23)
Average availability	88.2%	91.5%	(3.3)%	(4)
Average total MW in operation	6,895	6,911	(16)	—
Average capacity factor, excluding peakers	43.6%	56.5%	(12.9)%	(23)
Steam Adjusted Heat Rate	7,418	7,316	(102)	(1)

West — Commodity Margin in our West segment for the year ended December 31, 2011 was comparable to the year ended December 31, 2010. During the year ended December 31, 2011, we experienced higher Commodity Margin contribution from hedges as well as the positive impact of origination activities in 2011 compared to 2010. These positive factors were offset by lower Spark Spreads resulting from a significant increase in hydroelectric generation in California in 2011 compared to 2010, and lower Commodity Margin resulting from an unscheduled outage at OMEC during the second quarter of 2011. Consistent with weaker price conditions, generation decreased 23% for the year ended December 31, 2011 compared to 2010. Average availability decreased by 4% due to an increase in the duration of outages during the second quarter of 2011 compared to the second quarter of 2010, as the weaker price environment provided an opportunity to extend the duration of scheduled maintenance outages due to limited opportunity costs. Our average total MW in operation decreased 16 MW primarily due to the retirement of our Pittsburg power plant in March 2010 as well as the expiration of our operating lease and subsequent retirement of our Watsonville (Monterey) cogeneration power plant in May 2010 which was partially offset by an increase related to the completion of turbine upgrades at two of our power plants in 2011.

Texas:	2011	2010	Change	% Change
Commodity Margin (in millions)	$ 469	$ 504	$ (35)	(7)
Commodity Margin per MWh generated	$ 14.41	$ 16.71	$ (2.30)	(14)
MWh generated (in thousands)	32,552	30,169	2,383	8
Average availability	89.0%	87.6%	1.4%	2
Average total MW in operation	6,988	7,166	(178)	(2)
Average capacity factor, excluding peakers	53.2%	48.1%	5.1%	11
Steam Adjusted Heat Rate	7,243	7,236	(7)	—

Texas — Commodity Margin in our Texas segment decreased by $35 million, or 7%, for the year ended December 31, 2011, compared to the year ended December 31, 2010. Despite an increase in Commodity Margin contributions from hedges, Commodity Margin was negatively impacted by unplanned outages at some of our power plants caused by an extreme cold weather event which occurred on February 2, 2011. Power prices increased dramatically as a result of the cold weather event and the plant outages, which required us to purchase physical replacement power at prices substantially above our hedged prices. Also contributing to the year over year decrease in Commodity Margin was the sale of a 25% undivided interest in the assets of our Freestone power plant in December 2010 which also drove a 178 MW, or 2% decrease in our average total MW in operation which was partially offset by an increase related to the completion of turbine upgrades at several of our power plants in 2011 and 2010. The decrease in Commodity Margin was partially offset by significantly higher power prices driven by extreme heat and drought conditions which increased Spark Spreads during the third quarter of 2011 on our relatively small open position.

North:	2011	2010	Change	% Change
Commodity Margin (in millions)	$ 704	$ 535	$ 169	32
Commodity Margin per MWh generated	$ 45.37	$ 57.79	$ (12.42)	(21)
MWh generated (in thousands)	15,517	9,258	6,259	68
Average availability	91.6%	90.7%	0.9%	1
Average total MW in operation	7,268	4,833	2,435	50
Average capacity factor, excluding peakers	35.9%	32.8%	3.1%	9
Steam Adjusted Heat Rate	7,919	7,819	(100)	(1)

North — Commodity Margin in our North segment increased by $169 million, or 32%, primarily due to the Conectiv Acquisition which closed on July 1, 2010 and our York Energy Center which achieved COD in March 2011 which were both also the primary driver of the period over period increase in generation as well as the 2,435 MW increase in average total MW in operation during the year ended December 31, 2011 compared to the year ended December 31, 2010. The increase in Commodity Margin was partially offset by lower capacity prices in the second half of 2011 compared to the same period in 2010. Average capacity factor, excluding peakers, increased 9% primarily due to scheduled outages at two of our power plants in the fourth quarter of 2010.

Southeast:	2011	2010	Change	% Change
Commodity Margin (in millions)	$ 240	$ 272	$ (32)	(12)
Commodity Margin per MWh generated	$ 12.64	$ 15.12	$ (2.48)	(16)
MWh generated (in thousands)	18,983	17,987	996	6
Average availability	91.9%	92.5%	(0.6)%	(1)
Average total MW in operation	6,083	6,083	—	—
Average capacity factor, excluding peakers	40.6%	38.0%	2.6 %	7
Steam Adjusted Heat Rate	7,312	7,315	3	—

Southeast — Commodity Margin in our Southeast segment decreased by $32 million, or 12%, for the year ended December 31, 2011 compared to the year ended December 31, 2010 largely due to the expiration of certain hedge contracts which benefited the year ended December 31, 2010 as well as lower Commodity Margin that resulted from unscheduled outages that occurred during the second and third quarters of 2011.

Commodity Margin by Segment for the Years Ended December 31, 2010 and 2009

The following tables show our Commodity Margin and related operating performance metrics by segment for the years ended December 31, 2010 and 2009. In the comparative tables below, favorable variances are shown without brackets while unfavorable variances are shown with brackets. The MWh generated by segment below represents generation from power plants that we both consolidated and operate.

West:	**2010**	**2009**	**Change**	**% Change**
Commodity Margin (in millions)	$ 1,080	$ 1,245	$ (165)	(13)
Commodity Margin per MWh generated	$ 34.94	$ 38.82	$ (3.88)	(10)
MWh generated (in thousands)	30,909	32,070	(1,161)	(4)
Average availability	91.5%	92.1%	(0.6)	(1)
Average total MW in operation	6,911	6,371	540	8
Average capacity factor, excluding peakers	56.5%	64.0%	(7.5)	(12)
Steam Adjusted Heat Rate	7,316	7,314	(2)	—

West — Commodity Margin in our West segment decreased by $165 million, or 13%, for the year ended December 31, 2010 compared to the year ended December 31, 2009, primarily resulting from a decrease of $102 million related to the expiration of the PCF arrangement in the fourth quarter of 2009, lower average hedge prices in 2010 compared to 2009, lower realized Spark Spreads on our open positions due to lower Market Heat Rates caused primarily by cooler temperatures in 2010 compared to 2009 and an overall increase in installed generation capacity as well as increased hydroelectric generation in California in 2010. Also contributing to the unfavorable period over period change was a decrease of $11 million for the sale of surplus emission allowances in the first quarter of 2009 which did not reoccur in 2010. The decrease in Commodity Margin was partially offset by an increase of $50 million related to higher REC revenue from new contracts associated with our Geysers Assets, $80 million from OMEC that achieved commercial operation in October 2009 and was consolidated on January 1, 2010 and a $12 million credit recognized in the second quarter of 2010 related to overcharges associated with a gas transportation contract. Average total MW in operation increased 540 MW, or 8%, due primarily to OMEC which was partially offset by the retirement of our Pittsburg power plant in March 2010 as well as the expiration of the operating lease and subsequent retirement of our Watsonville (Monterey) cogeneration power plant in May 2010. Our average capacity factor, excluding peakers, decreased by 12% for the year ended December 31, 2010 compared to 2009 due to the weaker price conditions in 2010 compared to 2009.

Texas:	**2010**	**2009**	**Change**	**% Change**
Commodity Margin (in millions)	$ 504	$ 644	$ (140)	(22)
Commodity Margin per MWh generated	$ 16.71	$ 21.69	$ (4.98)	(23)
MWh generated (in thousands)	30,169	29,687	482	2
Average availability	87.6%	90.0%	(2.4)	(3)
Average total MW in operation	7,166	7,156	10	—
Average capacity factor, excluding peakers	48.1%	47.4%	0.7	1
Steam Adjusted Heat Rate	7,236	7,142	(94)	(1)

Texas — Commodity Margin in our Texas segment decreased by $140 million, or 22%, for the year ended December 31, 2010 compared to the year ended December 31, 2009, primarily resulting from lower average hedge prices and lower realized Spark Spreads on open positions due to lower Market Heat Rates, particularly with regard to June 2010, which did not benefit from the extreme heat, congestion-driven pricing and tighter reserve margin that occurred in June 2009, as well as an overall increase in installed generation capacity in ERCOT in 2010 compared to 2009. Generation increased 2% driven by higher Spark Spreads in April 2010, as well as colder weather in January and February 2010 compared to the same periods in 2009.

North:	2010	2009	Change	% Change
Commodity Margin (in millions)	$ 535	$ 268	$ 267	#
Commodity Margin per MWh generated	$ 57.79	$ 51.06	$ 6.73	13
MWh generated (in thousands)	9,258	5,249	4,009	76
Average availability	90.7%	94.7%	(4.0)	(4)
Average total MW in operation	4,833	2,873	1,960	68
Average capacity factor, excluding peakers	32.8%	31.1%	1.7	5
Steam Adjusted Heat Rate	7,819	7,614	(205)	(3)

North — Commodity Margin in our North segment increased by $267 million primarily due to the Conectiv Acquisition which closed on July 1, 2010, higher realized Spark Spreads on open positions driven by much warmer weather in the second and third quarters of 2010 compared to the same periods in 2009, as well as colder weather in the latter fourth quarter of 2010 compared to the same period in 2009. The Conectiv Acquisition led to a 1,960 MW increase in our average total MW in operation as well as a 3,783 MWh increase in generation while stronger market pricing led to a 4% increase in generation among our legacy power plants for the year ended December 31, 2010 compared to the year ended December 31, 2009.

Southeast:	2010	2009	Change	% Change
Commodity Margin (in millions)	$ 272	$ 304	$ (32)	(11)
Commodity Margin per MWh generated	$ 15.12	$ 17.50	$ (2.38)	(14)
MWh generated (in thousands)	17,987	17,370	617	4
Average availability	92.5%	93.2%	(0.7)	(1)
Average total MW in operation	6,083	6,083	—	—
Average capacity factor, excluding peakers	38.0%	37.9%	0.1	—
Steam Adjusted Heat Rate	7,315	7,299	(16)	—

Southeast — Commodity Margin in our Southeast segment decreased by $32 million, or 11%, for the year ended December 31, 2010 compared to the year ended December 31, 2009. Our power plants in the Western half of the region experienced lower realized Spark Spreads on open positions, driven by lower Market Heat Rates. Partially offsetting these negative impacts, our power plants in the Eastern half of the region experienced higher realized Spark Spreads on open positions, driven by higher Market Heat Rates caused primarily by warmer weather in May and June 2010 and cooler weather in the fourth quarter of 2010 compared to the same periods in 2009. In addition, the overall decrease in Commodity Margin was partially offset by the non-recurring negative impact from the settlement of a disputed steam contract in the second quarter of 2009.

Adjusted EBITDA

We define Adjusted EBITDA as EBITDA adjusted for certain items described below and presented in the accompanying reconciliation. Adjusted EBITDA is not a measure calculated in accordance with U.S. GAAP, and should be viewed as a supplement to and not a substitute for our results of operations presented in accordance with U.S. GAAP. Our Corporate Revolving Facility includes a similar measure as a basis for our material covenants under the debt agreement that excludes our net interest in our unconsolidated subsidiaries and includes distributions received from unconsolidated investments. However, we believe that inclusion of our share of the Adjusted EBITDA of our unconsolidated subsidiaries is useful in evaluating our overall performance and therefore we include Adjusted EBITDA from our unconsolidated investments and exclude distributions received from our unconsolidated investments in our definition of Adjusted EBITDA. Adjusted EBITDA is not intended to represent cash flows from operations or net income (loss) as defined by U.S. GAAP as an indicator of operating performance. Furthermore, Adjusted EBITDA is not necessarily comparable to similarly-titled measures reported by other companies.

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

Additionally, we believe that investors commonly adjust EBITDA information to eliminate the effect of restructuring and other expenses, which vary widely from company to company and impair comparability. As we define it, Adjusted EBITDA represents EBITDA adjusted for the effects of impairment losses, gains or losses on sales, dispositions or retirements of assets, any unrealized gains or losses from accounting for derivatives, stock-based compensation expense, operating lease expense, non-cash gains and losses from foreign currency translations, major maintenance expense, gains or losses on the repurchase or extinguishment of debt and any other extraordinary, unusual or non-recurring items plus the Adjusted EBITDA from our discontinued operations and adjustments to reflect the Adjusted EBITDA from our unconsolidated investments. We adjust for these items in our Adjusted EBITDA as our management believes that these items would distort their ability to efficiently view and assess our core operating trends.

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

The tables below provide a reconciliation of Adjusted EBITDA to our income (loss) from operations on a segment basis and to net income attributable to Calpine on a consolidated basis for years ended December 31, 2011, 2010 and 2009 (in millions).

	2011					
	West	Texas	North	Southeast	Consolidation and Elimination	Total
Net loss attributable to Calpine						$ (190)
Net income attributable to the noncontrolling interest						1
Income tax benefit						(22)
Other (income) expense and debt extinguishment costs, net						115
Loss on interest rate derivatives						145
Interest expense, net						751
Income (loss) from operations	$ 518	$ (49)	$ 343	$ (17)	$ 5	$ 800
Add:						
Adjustments to reconcile income (loss) from operations to Adjusted EBITDA:						
Depreciation and amortization expense, excluding deferred financing costs[1]	192	135	138	92	(5)	552
Major maintenance expense	58	81	23	43	—	205
Operating lease expense	9	—	26	—	—	35
Unrealized (gain) loss on commodity derivative mark-to-market activity	(106)	123	3	5	—	25
Adjustments to reflect Adjusted EBITDA from unconsolidated investments[2][3]	—	—	36	—	—	36
Stock-based compensation expense	10	7	3	4	—	24
Loss on dispositions of assets	8	4	2	2	—	16
Contract amortization	—	—	8	—	—	8
Other	11	1	11	2	—	25
Total Adjusted EBITDA	$ 700	$ 302	$ 593	$ 131	$ —	$ 1,726

	2010					
	West	Texas	North	Southeast	Consolidation and Elimination	Total
Net income attributable to Calpine						$ 31
Discontinued operations, net of tax expense						(193)
Income tax benefit						(68)
Other (income) expense and debt extinguishment costs, net						106
Loss on interest rate derivatives						223
Interest expense, net						802
Income from operations	$ 380	$ 237	$ 250	$ 27	$ 7	$ 901
Add:						
Adjustments to reconcile income from operations to Adjusted EBITDA:						
Depreciation and amortization expense, excluding deferred financing costs[1]	207	150	111	112	(7)	573
Impairment losses	97	—	—	19	—	116
Major maintenance expense	27	87	18	25	—	157
Operating lease expense	19	—	26	—	—	45
Unrealized (gain) on commodity derivative mark-to-market activity	(54)	(54)	(17)	(18)	—	(143)
Gain on sale of assets	—	(119)	—	—	—	(119)
Adjustments to reflect Adjusted EBITDA from unconsolidated investments[2][3]	—	—	34	—	—	34
Stock-based compensation expense	11	8	2	3	—	24
Loss on dispositions of assets	—	9	—	1	—	10
Conectiv acquisition-related costs[4]	—	—	36	—	—	36
Other	2	—	1	—	—	3
Adjusted EBITDA from continuing operations	689	318	461	169	—	1,637
Adjusted EBITDA from discontinued operations	75	—	—	—	—	75
Total Adjusted EBITDA	$ 764	$ 318	$ 461	$ 169	$ —	$ 1,712

	2009					
	West	Texas	North	Southeast	Consolidation and Elimination	Total
Net income attributable to Calpine						$ 149
Net loss attributable to the noncontrolling interest						(4)
Discontinued operations, net of tax expense						(35)
Income tax expense						15
Other (income) expense and debt extinguishment costs, net						89
Interest expense, net						799
Income (loss) from operations	$ 681	$ 166	$ 126	$ 47	$ (7)	$ 1,013
Add:						
Adjustments to reconcile income (loss) from operations to Adjusted EBITDA:						
Depreciation and amortization expense, excluding deferred financing costs[1]	186	130	67	84	(8)	459
Impairment losses	4	—	—	—	—	4
Major maintenance expense	77	49	5	32	—	163
Operating lease expense	21	—	26	—	—	47
Unrealized (gain) loss on commodity derivative mark-to-market activity	(110)	59	(42)	14	—	(79)
Adjustments to reflect Adjusted EBITDA from unconsolidated investments[2][3]	(16)	—	33	—	—	17
Stock-based compensation expense	17	12	3	6	—	38
Loss on dispositions of assets	11	14	2	5	—	32
Other	6	—	—	—	—	6
Adjusted EBITDA from continuing operations	877	430	220	188	(15)	1,700
Adjusted EBITDA from discontinued operations	82	—	—	—	—	82
Total Adjusted EBITDA	$ 959	$ 430	$ 220	$ 188	$ (15)	$ 1,782

(1) Depreciation and amortization expense in the income (loss) from operations calculation on our Consolidated Statements of Operations excludes amortization of other assets.

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

(3) Adjustments to reflect Adjusted EBITDA from unconsolidated investments include unrealized (gain) loss on mark-to-market activity of $1 million, $1 million and $(47) million for the years ended December 31, 2011, 2010 and 2009, respectively.

(4) Includes $26 million included in sales, general and other administrative expense and $10 million included in plant operating expense.

LIQUIDITY AND CAPITAL RESOURCES

Our business is capital intensive. Our ability to successfully implement our strategy is dependent on the continued availability of capital on attractive terms. In addition, our ability to successfully operate our business is dependent on maintaining sufficient liquidity. We believe that we have adequate resources from a combination of cash and cash equivalents on hand and cash expected to be generated from future operations to continue to meet our obligations as they become due.

Liquidity

At December 31, 2011, we had $1,252 million in cash and cash equivalents and $194 million of restricted cash. Amounts available for future borrowings were $560 million under our Corporate Revolving Facility. The following table provides a summary of our liquidity position at December 31, 2011 and 2010 (in millions):

	2011	2010
Cash and cash equivalents, corporate[(1)]	$ 946	$ 1,058
Cash and cash equivalents, non-corporate	306	269
Total cash and cash equivalents	1,252	1,327
Restricted cash	194	248
Revolving facility(ies) availability[(2)]	560	623
Letter of credit availability[(3)]	7	35
Total current liquidity availability	$ 2,013	$ 2,233

(1) Includes $34 million and $6 million of margin deposits held by us posted by our counterparties at December 31, 2011 and 2010, respectively.

(2) On December 10, 2010, we executed our $1.0 billion Corporate Revolving Facility, which replaced our $1.0 billion revolver under our First Lien Credit Facility. At December 31, 2010, the letters of credit issued under our First Lien Credit Facility were either replaced by letters of credit issued under our Corporate Revolving Facility or back-stopped by an irrevocable standby letter of credit issued by a third party. Our letters of credit under our Corporate Revolving Facility at December 31, 2010 include those that were back-stopped of approximately $83 million. The back-stopped letters of credit were returned and extinguished during the first quarter of 2011. The balance at December 31, 2010, includes availability under the NDH Project Debt, which was retired on March 9, 2011.

(3) Includes availability under our CDHI letter of credit facility. On January 10, 2012, we increased the CDHI letter of credit facility to $300 million and extended the maturity date to January 2, 2016.

Our principal source for future liquidity is cash flows generated from our operations. Our principal uses of liquidity and capital resources, outside of those required for our operations, include, but are not limited to, collateral requirements to support our commercial hedging and optimization activities, debt service obligations including principal and interest payments and capital expenditures for construction, project development and other growth initiatives. In addition, we may use capital resources to opportunistically repurchase our shares of common stock. The ultimate decision to allocate capital to share repurchases will be based upon the expected returns compared to alternative uses of capital. We believe that cash on hand and expected future cash flows from operations will be sufficient to meet our liquidity needs for our operations, both in the near and longer term.

Cash Management - We manage our cash in accordance with our cash management system subject to the requirements of our Corporate Revolving 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 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 creditworthy 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 have never paid cash dividends on our common stock. Future cash dividends, if any, will be at the discretion of our Board of Directors and will depend upon, among other things, our future operations and earnings, capital requirements, general financial condition, contractual and financing restrictions and such other factors as our Board of Directors may deem relevant.

Liquidity Sensitivity

Significant changes in commodity prices and Market Heat Rates can have an impact on our liquidity as we use margin deposits, cash prepayments and letters of credit as credit support (collateral) with and from our counterparties for commodity procurement and risk management activities. Utilizing our portfolio of transactions subject to collateral exposure, we estimate that as of January 20, 2012, an increase of $1/MMBtu in natural gas prices would result in an increase of collateral required by approximately $400 million. If natural gas prices decreased by $1/MMBtu, we estimate that our collateral requirements would decrease by approximately $391 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. Historical relationships of natural gas and Market Heat Rate movements for our portfolio of assets have been volatile over time and are influenced by the absolute price of natural gas; therefore, we derived a statistical analysis that implies that a change of $1/MMBtu in natural gas approximates an average Market Heat Rate change of 500 Btu/KWh at current natural gas price levels. We estimate that at January 20, 2012, an increase of 500 Btu/KWh in the Market Heat Rate would result in an increase in collateral required by approximately $41 million. If Market Heat Rates were to fall at a similar rate, we estimate that our collateral required would decrease by $47 million. These amounts are not necessarily indicative of the actual amounts that could be required, which may be higher or lower than the amounts estimated above, and also exclude any correlation between the changes in natural gas prices and Market Heat Rates that may occur concurrently. These sensitivities will change as new contracts or hedging activities Wmay be 19gher or the Market et ies that a change of $1/

- *Garrison (Delaware)*: Actively permitting 618 MW of new combined-cycle capacity at a development site secured by a lease option with the City of Dover. PJM's system impact study for the first phase (309MW) and the feasibility study for the second phase (309 MW) have been completed. Both studies are being reviewed internally. Environmental permitting, site development planning and development engineering are underway.
- *Edge Moor (Delaware)*: A nominal 300 MW combined-cycle development project located at our Edge Moor facility which will leverage existing infrastructure. PJM is currently conducting a system impact study which will provide a detailed report on the project's interconnection costs.

Russell City Energy Center

The Russell City Energy Center is under construction and continues to move forward with expected COD in 2013. Upon completion, this project will bring on line approximately 429 MW of net interest baseload capacity (464 MW with peaking capacity) representing our 75% share. We are in possession of all required approvals and permits, and we closed on construction financing on June 24, 2011. The project's prevention of significant deterioration permit is currently the subject of an ongoing appeal at the U.S. Court of Appeals for the Ninth Circuit brought by Chabot-Las Positas Community College District against the EPA. Upon completion, the Russell City Energy Center is contracted to deliver its full output to PG&E under a ten-year PPA.

Los Esteros

During 2009, we and PG&E negotiated a new PPA to replace the existing California Department of Water Resources contract and facilitate the upgrade of our Los Esteros Critical Energy Facility from a 188 MW simple-cycle generation power plant to a 308 MW combined-cycle generation power plant, which will also increase the efficiency and environmental performance of the power plant by lowering the Heat Rate. The ten-year PPA and related agreements with PG&E have received all of the necessary approvals and licenses, which are now effective. The California Energy Commission has renewed our license and emission limits, which is final. The Bay Area Air Quality Management District issued its renewal of the Authority to Construct. We began construction in the second quarter of 2011 and obtained construction financing on August 23, 2011. We expect COD in 2013.

Geysers Assets Expansion

We continue to look to expand our production from our Geysers Assets. Beginning in the fourth quarter of 2009, we conducted an exploratory drilling program, which effectively proved the commercial viability of the steam field in the northern part of our Geysers Assets. We have received Conditional Use Permits from Sonoma County and are pursuing the additional required permitting. We are pursuing commercial arrangements which will need to be in place prior to commencing expansion activities. We continue to believe our northern Geysers Assets have potential for development. In the meantime, we have connected certain test wells to our existing power plants to capture incremental production from those wells, while continuing with the permitting process, baseline engineering work and sales efforts for an expansion.

ERCOT Channel and Deer Park Expansions

We continue to evaluate the ERCOT market for expansion opportunities based on tightening reserve margins and potential impact of EPA regulations on generation in Texas. At both our Deer Park and Channel Energy Centers, we have the ability to install an additional combustion turbine generator and connect to the existing steam turbine generator to expand the capacity of these facilities and to improve the overall efficiency. In September 2011, we filed an air permit application with the Texas Commission on Environmental Quality ("TCEQ") and the EPA to expand the Deer Park Energy Center by approximately 275 MW. In November 2011, we filed similar permits with the TCEQ and the EPA to expand the Channel Energy Center by approximately 275 MW.

Mankato Power Plant Expansion Proposal

In March 2011, Xcel Energy Inc. ("Xcel") filed an application with the Minnesota Public Utilities Commission ("MPUC") to construct a new 700 MW natural gas-fired, combined-cycle facility to be located at its existing Black Dog site. The MPUC required Xcel to also seek potential third party alternatives so that MPUC could compare any offers to Xcel's proposal. We proposed to expand our Mankato power plant, a 375 MW natural gas-fired, combined-cycle power plant, by 345 MW under a PPA with Xcel. We believe that our proposal is less expensive, environmentally preferable and a closer match to Xcel's demand forecast than its self-build proposal. The matter was referred to a contested case hearing. Xcel subsequently filed to withdraw its application for the Black Dog expansion, which may affect the status of our proposed Mankato expansion. Xcel's request is currently pending review by an administrative law judge. A decision is not expected until the second quarter of 2012.

Turbine Upgrades

We continue to move forward with our turbine upgrade program. Through December 31, 2011, we have completed the upgrade of ten Siemens and five GE turbines and have agreed to upgrade approximately six additional Siemens and GE turbines (and may upgrade additional turbines in the future). Our turbine upgrade program is expected to increase our generation capacity in total by approximately 275 MW. This upgrade program began in the fourth quarter of 2009 and is scheduled through 2014. The upgraded turbines have been operating with Heat Rates consistent with expectations.

Major Maintenance and Capital Spending

Our major maintenance and capital spending remains an important part of our business. Our expected expenditures for 2012 are as follows (in millions):

	2012
Major maintenance expense	$ 195
Capital expenditures, operations, net of expected grants	165
Growth related capital expenditures	443
Total major maintenance expense and capital spending	803
Less: Amounts expected to be funded with financing[(1)]	(443)
Net major maintenance expense and capital spending	$ 360

(1) Consist of amounts to be drawn under our Russell City Project Debt and Los Esteros Project Debt.

NOLs

We have significant NOLs that will provide future tax deductions when we generate sufficient taxable income during the applicable carryover periods. As discussed in Note 10 of the Notes to Consolidated Financial Statements, we elected to consolidate our CCFC and Calpine groups for federal income tax reporting purposes during the first quarter of 2011. As a result of the consolidation, we will be able to utilize approximately $76 million additional Calpine group NOLs against CCFC group deferred tax liabilities. At December 31, 2011, our consolidated federal NOLs totaled approximately $7.9 billion. See Note 10 of the Notes to Consolidated Financial Statements for further discussion of our NOLs.

As a result of the settlement with holders of the CalGen Third Lien Debt and the final distribution to the holders of allowed unsecured claims in accordance with our Plan of Reorganization in 2011, we recognized approximately $66 million and $39 million for federal and state income tax purposes, respectively, in cancellation of debt income related to this distribution.

Cash Flow Activities

The following table summarizes our cash flow activities for the years ended December 31, 2011, 2010 and 2009 (in millions):

	2011	2010	2009
Beginning cash and cash equivalents	$ 1,327	$ 989	$ 1,657
Net cash provided by (used in):			
Operating activities	775	929	761
Investing activities	(836)	(831)	(250)
Financing activities	(14)	240	(1,179)
Net increase (decrease) in cash and cash equivalents	(75)	338	(668)
Ending cash and cash equivalents	$ 1,252	$ 1,327	$ 989

2011 — 2010

Net Cash Provided By Operating Activities

Cash provided by operating activities for the year ended December 31, 2011, was $775 million compared to $929 million for the year ended December 31, 2010. The decrease in cash provided by operating activities was primarily due to:

- *Working capital* — Working capital employed increased by approximately $194 million for the year ended December 31, 2011 compared to 2010 after adjusting for debt related balances and non-hedging interest rate swaps which did

not impact cash provided by operating activities. The increase was primarily due to a reduction in margin requirements during the year ended December 31, 2010.

- *Interest paid* — Cash paid for interest, inclusive of interest rate swaps in hedging relationships, increased by $21 million to $656 million for the year ended December 31, 2011, as compared to $635 million for 2010. The increase was primarily due to timing of interest payments on the issuance of First Lien Notes, Term Loan and New Term Loan as compared to the previously outstanding First Lien Credit Facility and project debt.
- *Prepayment Premiums* — For the year ended December 31, 2011, we paid $13 million of prepayment premiums related to the extinguishment of the NDH Project Debt.

Our decrease in cash provided by operating activities was partially offset by the following:

- *Income from operations* — Income from operations, adjusted for non-cash items increased by $41 million for the year ended December 31, 2011, as compared to 2010. Non-cash items consist primarily of depreciation and amortization, gains and losses on sales of assets, impairment losses, income and losses from unconsolidated investments and unrealized gains and losses in mark to market activity.

Net Cash Used In Investing Activities

Cash flows used in investing activities for the year ended December 31, 2011, were $836 million compared to cash flows used in investing activities of $831 million for the year ended December 31, 2010. The difference was primarily due to:

- *Purchase of Conectiv assets and BRSP* — We purchased the Conectiv assets and BRSP for approximately $1.7 billion in 2010. There were no acquisitions in 2011.
- *Capital expenditures* — Capital expenditures increased by $314 million primarily resulting from construction activity at the Russell City Energy Center, Los Esteros Critical Energy Facility and York Energy Center combined with our turbine upgrade program.
- *Lower proceeds from sales of power plants, interests and other* — In the year ended December 31, 2011, we received proceeds of approximately $13 million from the disposal of other plant assets compared to proceeds of approximately $954 million primarily relating to the sale of Blue Spruce, Rocky Mountain and a 25% undivided interest in the assets of our Freestone power plant in the year ended December 31, 2010.
- *Settlement of non-hedging interest rate swaps* — During the year ended December 31, 2011 we made payments on interest rate swap derivative instruments associated with swaps that formerly hedged variable rate debt which was converted to fixed rate debt of $189 million compared to payments of $69 million during the same period in 2010.
- *Restricted cash* — The net decrease in restricted cash was $54 million for the year ended December 31, 2011, compared to $322 million for the same period in 2010. The decrease in restricted cash in 2011 as compared to 2010 was primarily due to the maturity of project debt and the corresponding reduction in restricted cash requirements.
- *Transmission credits* — During the year ended December 31, 2011, we paid $31 million for transmission credits related to construction of our Russell City Energy Center.

Net Cash Provided By (Used In) Financing Activities

Cash flows used in financing activities were $14 million in the year ended December 31, 2011, compared to cash flows provided by financing activities of $240 million for the year ended December 31, 2010. The change in cash flows provided by (used in) financing activities was primarily related to:

- *Issuance of the Term Loan and New Term Loan* — During the year ended December 31, 2011, we received proceeds of approximately $1.7 billion from the issuance of the Term Loan and New Term Loan. We used the proceeds to repay our NDH Project Debt of approximately $1.3 billion resulting in a net increase of $374 million.
- *Issuance of the First Lien Notes* — We received proceeds of approximately $1.2 billion from the issuance of the 2023 First Lien Notes and used those proceeds to terminate the First Lien Credit Facility in accordance with its repayment terms resulting in a net increase of $5 million during the year ended December 30, 2011, compared to a net increase of $14 million during the year ended December 31, 2010.
- *Reduced proceeds from project debt* — During the year ended December 31, 2011, we received proceeds of approximately $327 million related to our Russell City Project Debt and Los Esteros Project Debt. During 2010 we received proceeds of approximately $1.3 billion to fund the Conectiv acquisition.

- *Lower Repayments of Project Debt* — During the year ended December 31, 2011, we made repayments on project debt of approximately $550 million, compared to approximately $937 million in the year ended December 31, 2010.
- *Increased Contributions from noncontrolling interest holder* — During the year ended December 31, 2011, we received proceeds of approximately $34 million from a noncontrolling interest holder in Russell City Energy Center, compared to contributions of approximately $17 million in the year ended December 31, 2010.
- *Decreased Finance Costs* — During the year ended December 31, 2011, primarily due to the refinancing of the First Lien Credit Facility and the NDH Project Debt, we incurred $81 million in finance costs primarily related to the issuance of the First Lien Notes and project debt, compared to $136 million in finance costs primarily related to the issuance of the First Lien Notes and project debt.
- *Stock Repurchases* — During the year ended December 31, 2011, we made payments of approximately $119 million under the share repurchase program announced on August 23, 2011. There were no similar repurchases during the same period in 2010.

2010 — 2009

Net Cash Provided By Operating Activities

Cash provided by operating activities for the year ended December 31, 2010, improved to $929 million compared to $761 million for the year ended December 31, 2009. Our improvement in cash provided by operating activities was primarily due to:

- *Working capital* — Working capital employed, after adjusting for debt related balances and derivative activities which did not impact cash provided by operating activities, decreased by approximately $188 million for the year ended December 31, 2010 compared to 2009. The decrease was primarily due to reduced Commodity Margin requirements.
- *Interest paid* — Cash paid for interest, inclusive of interest rate swaps in hedging relationships, decreased by $126 million to $635 million for the year ended December 31, 2010, as compared to $761 million for 2009, primarily due to the timing of interest payments and the replacement of the First Lien Credit Facility with First Lien Notes at lower fixed interest rates.

Our improvements in cash provided by operating activities were partially offset by the following:

- *Income from operations* — Income from operations, adjusted for non-cash items decreased by $43 million for the year ended December 31, 2010, as compared to 2009. Non-cash items consist primarily of depreciation and amortization, gains and losses on sales of assets, impairment losses, income and losses from unconsolidated investments and unrealized gains and losses in mark to market activity.
- *Cash taxes* — Net cash paid for taxes in 2010 was approximately $17 million compared to net cash received for taxes of approximately $37 million in 2009. In 2009, we received refunds from foreign tax jurisdictions with no such refunds in 2010.

Net Cash Used In Investing Activities

Cash flows used in investing activities for the year ended December 31, 2010, were $831 million compared to cash flows used in investing activities of $250 million for the year ended December 31, 2009. The increase in cash flows used in investing activities was primarily due to:

- *Purchase of Conectiv assets and BRSP* — We purchased the Conectiv assets and BRSP for approximately $1.7 billion in 2010. There were no acquisitions in 2009.
- *Capital expenditures* — Capital expenditures increased by $190 million primarily resulting from construction activity at our York Energy Center and Russell City Energy Center combined with our Geysers Assets expansion activities.
- *Settlement of non-hedging interest rate swaps* — In the year ended December 31, 2010 we paid $69 million on interest rate swap losses associated with swaps that formerly hedged the variable rate debt which was converted to fixed rate debt in the year. We made no similar payments in 2009.

The increase in cash flows used in investing activities was partially offset by:

- *Decrease in restricted cash* — Restricted cash decreased $322 million in 2010 compared to a $59 million increase in 2009. The decrease was primarily due to releases of restrictions on cash resulting from the repayment of project debt.
- *Sales of power plants, interests and other* — We received proceeds of approximately $954 million from the sale of our 100% ownership interests in Blue Spruce and Rocky Mountain, combined with the sale of a 25% undivided interest in the assets of our Freestone power plant. We had no significant asset sales in 2009.

Net Cash Provided By (Used In) Financing Activities

Cash flows provided by financing activities increased approximately $1.4 billion to $240 million for the year ended December 31, 2010, compared to cash flows used in financing activities of approximately $1.2 billion for the comparable period in 2009. The change in cash flows provided by financing activities was primarily related to:

- *Issuance of the First Lien Notes* — In the year ended December 31, 2010, we received proceeds of approximately $3.5 billion from the issuance of First Lien Notes. We used these proceeds to make repayments on the First Lien Credit Facility of approximately $3.4 billion resulting in a net increase of $50 million.
- *Lower Repayments on the First Lien Credit Facility* — In the year ended December 31, 2010, we made regularly scheduled payments on the First Lien Credit Facility of approximately $36 million, a decrease of $24 million compared to payments of $60 million for the year ended December 31, 2009. Additionally, in the year ended December 31, 2009, we repaid $725 million on our First Lien Credit Facility revolver.
- *Increase in Project Debt* — In the year ended December 31, 2010, we received proceeds of approximately $1.3 billion from project debt used to finance the Conectiv Acquisition, a $238 million increase compared to project debt issued in the year ended December 31, 2009, which was primarily due to the refinancing of CCFC.
- *Lower Repayments of Project Debt* — In the year ended December 31, 2010, we made repayments on project debt of approximately $937 million, a decrease of $424 million compared to the prior year. The decrease is primarily due to the repayment of approximately $418 million related to the Blue Spruce and Rocky Mountain transaction in 2010, compared to approximately $1.1 billion of repayments related to the CCFC Refinancing in 2009. Additionally, we made higher payments of approximately $239 million on other project debt in the year ended December 31, 2010.
- *Increased Finance Costs* — The increase in cash flows provided by financing activities was partially offset by an increase in finance costs of $71 million. In the year ended December 31, 2010, we incurred $136 million in finance costs primarily related to the issuance of the First Lien Notes and project debt, compared to $65 million incurred in 2009 to facilitate an amendment to the First Lien Credit Facility and to refinance other project debt.

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, ISOs 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. We have concentrations of credit risk with a few of our commercial customers relating to our sales of power, steam and hedging and optimization activities. Currently, certain of our marketing counterparties within the energy industry have below investment grade credit ratings. We believe that our credit policies and portfolio of transactions adequately monitor and diversify our credit risk, and currently our counterparties are performing and financially settling timely according to their respective agreements.

We also have unfunded credit exposure to several financial institutions domiciled in European countries that are currently experiencing stressed economic and financial conditions related to our Russell City Project Debt, Los Esteros Project Debt, miscellaneous project finance letter of credit facilities and interest rate derivative contracts. These financial institutions continue to perform in accordance with the terms of the applicable agreements. Should one or all of these financial institutions be unable to perform under their obligations, it would not have a material adverse effect on our financial position or results of operations. The table below sets forth our unfunded exposure for these financial institutions by country of domicile as of December 31, 2011 (in millions).

Country of Domicile	December 31, 2011
France	$ 96
Spain	75
Germany	66
Italy	50
Total unfunded exposure	$ 287

Credit Considerations

Our credit rating has, among other things, generally required us to post significant collateral with our hedging counterparties. Our collateral is generally in the form of cash deposits, letters of credit or first liens on our assets. See also Note 9 of the Notes to Consolidated Financial Statements for our use of collateral. Our credit rating has 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 hedging transactions and provide adequate collateral.

On September 30, 2011, Standard and Poor's Ratings Services upgraded our corporate credit rating to B+ from B and upgraded the secured credit rating of our First Lien Notes, Term Loan, New Term Loan and Corporate Revolving Facility to BB- from B+, both with stable outlooks. According to Standard and Poor's credit opinion, the ratings upgrades resulted from our Conectiv Acquisition, recent market trends that benefit our natural gas-fired power plants such as low natural gas prices and recent EPA regulations, recent corporate refinancing transactions which extended our debt maturities and our ability to generate positive cash flow from our operations. At December 31, 2011, our First Lien Notes, Term Loan, New Term Loan, Corporate Revolving Facility and our corporate rating had the following ratings and commentary from Standard and Poor's and Moody's Investors Service:

	Standard and Poor's	Moody's Investors Service
First Lien Notes, Term Loan, New Term Loan and Corporate Revolving Facility rating	BB-	B1
Corporate rating	B+	B1
Commentary	Stable	Stable

Off Balance Sheet Arrangements

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 up to Calpine Corporation, 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 15 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, 2011, our equity method investees (Greenfield LP and Whitby) had aggregate debt outstanding of $462 million. Based on our pro rata share of each of the investments, our share of such debt would be approximately $231 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 — 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 in the ordinary course of such subsidiaries' respective business. Such arrangements include guarantees, standby letters of credit and surety bonds for power

and natural gas purchase and sale arrangements and contracts associated with the development, construction, operation and maintenance of our fleet of power plants. 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. Our primary commercial obligations as of December 31, 2011, are as follows (in millions):

	Amounts of Commitment Expiration per Period						
Guarantee Commitments	2012	2013	2014	2015	2016	Thereafter	Total Amounts Committed
Guarantee of subsidiary debt[1]	$ 76	$ 73	$ 272	$ 36	$ 36	$ 236	$ 729
Standby letters of credit[2][4]	669	45	—	—	—	49	763
Surety bonds[3][4][5]	—	—	—	—	—	4	4
Guarantee of subsidiary operating lease payments[4]	7	7	3	—	—	—	17
Total	$ 752	$ 125	$ 275	$ 36	$ 36	$ 289	$ 1,513

(1) Represents Calpine Corporation guarantees of certain project debt, power plant capital leases and related interest. All guaranteed capital leases are recorded on our Consolidated Balance Sheets.

(2) The standby letters of credit disclosed above represent those disclosed in Note 6 of the Notes to Consolidated Financial Statements.

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

(4) These are contingent off balance sheet obligations.

(5) As of December 31, 2011, $4 million of cash collateral is outstanding related to these bonds.

Contractual Obligations — Our contractual obligations related to continuing operations as of December 31, 2011, are as follows (in millions):

	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Operating lease obligations[1]	$ 787	$ 56	$ 102	$ 92	$ 537
Purchase obligations:					
Turbine commitments	$ 47	$ 35	$ 12	$ —	$ —
Commodity purchase obligations[2]	4,600	566	897	739	2,398
LTSA	70	12	17	10	31
Cost to complete construction projects	362	316	46	—	—
Other purchase obligations[3]	2,435	188	362	357	1,528
Total purchase obligations[4]	$ 7,514	$ 1,117	$ 1,334	$ 1,106	$ 3,957
Debt[5]	$ 10,419	$ 88	$ 494	$ 1,341	$ 8,496
Other contractual obligations:					
Interest payments on debt[5][6]	$ 5,697	$ 710	$ 1,422	$ 1,337	$ 2,228
Liability for uncertain tax positions	48	—	22	—	26
Interest rate swap agreement[6]	329	170	88	48	23
Total other contractual obligations	$ 6,074	$ 880	$ 1,532	$ 1,385	$ 2,277

(1) Included in the total are future minimum payments for power plant, office and equipment and land and other operating leases. See Note 15 of the Notes to Consolidated Financial Statements for more information.

(2) The amounts presented here include contracts for the purchase, transportation, or storage of commodities accounted for as executory contracts and therefore not recognized as liabilities on our Consolidated Balance Sheet.

(3) The amounts presented here include water agreements, transmission agreements, parts supply agreements and other purchase obligations.

(4) The amounts included above for purchase obligations represent the minimum requirements under contract.

(5) A note payable totaling $49 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.

(6) Amounts are projected based upon interest rates at December 31, 2011.

Special Purpose Subsidiaries

Pursuant to applicable transaction agreements, we have established certain of our entities separate from Calpine Corporation 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: GEC Holdings, LLC, Gilroy Energy Center, LLC, Creed Energy Center, LLC, Goose Haven Energy Center, LLC, Calpine Gilroy Cogen, L.P., Calpine Gilroy 1, Inc., Calpine King City Cogen, LLC, Calpine Securities Company, L.P. (a parent company of Calpine King City Cogen, LLC), Calpine King City, LLC (an indirect parent company of Calpine Securities Company, L.P.), Russell City Energy Company, LLC and OMEC. The following disclosures are required under certain applicable agreements and pertain to some of these entities. The financial information provided below represents the assets and liabilities for some of the special purpose subsidiaries as reflected on our Consolidated Balance Sheets. These amounts may differ materially from the assets and liabilities for these entities that present individual financial statements on a stand-alone basis to their project lenders.

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 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 met the criteria of a mandatorily redeemable financial instrument that was classified as debt due to certain preferential distributions to the third party. In the third quarter of 2011, the GEC 4% senior secured notes and the debt related to the GEC Holdings, LLC mandatorily redeemable financial instrument were fully repaid. On December 22, 2011, we executed purchase agreements to purchase two of the third party equity interests in GEC Holdings, LLC. The closing of these transactions are subject to FERC approval and the terms of the agreements. The following table sets forth selected financial information of GEC at December 31, 2011 (in millions):

	2011
Assets	$ 464
Liabilities	8

RISK MANAGEMENT AND COMMODITY ACCOUNTING

Our hedging strategy and our commercial efforts attempt to maximize our risk adjusted Commodity Margin by leveraging our knowledge, experience and fundamental views on gas and power. We actively seek to manage the commodity risks of our portfolio, utilizing multiple strategies of buying and selling power, natural gas and Heat Rate contracts to manage our Spark Spread and products that manage geographic price differences (basis differential). We have approximately 371 MW of capacity from power plants where we purchase fuel oil to meet our generation requirements if required; however, we have not currently entered into any hedging or optimization transactions for our fuel oil requirements as we do not expect fuel oil requirements to be material to us, but may elect to do so in the future.

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 for or we elect not to designate as hedges under hedge accounting guidelines, such as commodity options transactions and instruments that settle on power price to natural gas price relationships (Heat Rate swaps and options) or instruments that settle on power price relationships between delivery points. 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. We use derivative instruments, which include physical commodity contracts and financial commodity instruments such as OTC and exchange traded swaps, futures, options, forward agreements and instruments that settle on the power price to natural gas price relationships (Heat Rate swaps and options) for the purchase and sale of power, natural gas, and emission allowances to manage commodity price risk and to maximize the risk-adjusted returns from our power and natural gas assets. We conduct these hedging and optimization activities within a structured risk management framework based on controls, policies and procedures. We monitor these activities through active and ongoing management and oversight, defined roles and responsibilities, and daily risk measurement and reporting. Additionally, we seek to manage the associated risks through diversification, by controlling position sizes, by using portfolio position limits, and by entering into offsetting positions that lock in a margin. We also are exposed 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 or we do not elect either hedge accounting or the normal purchase normal sale exemption are recognized currently in earnings within operating revenues in the case of power transactions, and within fuel and purchased energy expense, in the case of natural gas transactions. Our future hedged status, and marketing and optimization activities are subject to change as determined by our commercial operations group, Chief Risk Officer, Risk Management Committee of senior management and Board of Directors.

We have economically hedged a portion of our expected generation and natural gas portfolio mostly through power and natural gas forward physical and financial transactions ; however, we remain susceptible to significant price movements for 2012 and beyond. 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 use a combination of PPAs and other hedging instruments to manage our variability in future cash flows. At December 31, 2011, the maximum length of time that our PPAs extended was approximately 23 years into the future and the maximum length of time over which we were hedging using commodity and interest rate derivative instruments was 3 and 12 years, respectively.

We have historically used interest rate swaps to adjust the mix between our fixed and variable rate debt. To the extent eligible, our interest rate swaps have been designated as cash flow hedges, and changes in fair value are recorded in OCI to the extent they are effective with gains and losses reclassified into earnings in the same period during which the hedged forecasted transaction affects earnings. The reclassification of unrealized losses from AOCI into income and the changes in fair value and settlements subsequent to the reclassification date of the interest rate swaps formerly hedging our First Lien Credit Facility is presented separately from interest expense as loss on interest rate derivatives on our Consolidated Statements of Operations. On January 14, 2011, we repaid the remaining balance under the First Lien Credit Facility term loans with the proceeds received from the issuance of the 2023 First Lien Notes and the unrealized losses related to these interest rate swaps of approximately $91 million remaining in AOCI were reclassified out of AOCI and into income as additional loss on interest rate derivatives during 2011. In addition, we reclassified approximately $17 million in unrealized losses in AOCI to loss on interest rate derivatives during 2011 resulting from the repayment of project debt in 2011. During 2010, we reclassified approximately $206 million out of AOCI and into income as additional loss on interest rate derivatives related to interest rate swaps formerly hedging our First Lien Credit Facility term loans.

Assuming constant December 31, 2011 power and natural gas prices and interest rates, we estimate that pre-tax net gains of $15 million would be reclassified from AOCI into earnings during the next 12 months as the hedged transactions settle; however, the actual amounts that will be reclassified will vary based on changes in natural gas and power prices as well as interest rates. Therefore, we are unable to predict what the actual reclassification from AOCI into earnings (positive or negative) will be for the next 12 months.

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, MWh and $ notional amounts); changing commodity market prices, principally for power and natural gas; our credit standing and that of our counterparties for energy commodity derivatives; and prevailing interest rates for our interest rate swaps. Since prices for power and natural gas and interest rates are volatile, 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. Our derivative assets have increased to approximately $1.2 billion at December 31, 2011, compared to $0.9 billion at December 31, 2010, and our derivative liabilities have increased to approximately $1.4 billion at December 31, 2011, compared to $1.1 billion at December 31, 2010. At December 31, 2011, the fair value of our level 3 derivative assets and liabilities represent only a small portion of our total assets and liabilities (less than 1%). See Note 7 of the Notes to Consolidated Financial Statements for further information related to our level 3 derivative assets and liabilities.

The change in fair value of our outstanding commodity and interest rate derivative instruments from January 1, 2011, through December 31, 2011, is summarized in the table below (in millions):

	Interest Rate Swaps	Commodity Instruments	Total
Fair value of contracts outstanding at January 1, 2011	$ (367)	$ 174	$ (193)
Items recognized or otherwise settled during the period[1][2]	214	(203)	11
Fair value attributable to new contracts	(46)	(118)	(164)
Changes in fair value attributable to price movements	(98)	198	100
Changes in fair value attributable to nonperformance risk	(13)	—	(13)
Fair value of contracts outstanding at December 31, 2011[3]	$ (310)	$ 51	$ (259)

(1) Interest rate settlements consist of recognized losses from former interest rate cash flow hedges of $18 million that were de-designated as a result of the repayment of project debt in 2011, $69 million related to recognition of losses from settlements

of designated cash flow hedges and $127 million in losses from settlements of undesignated interest rate swaps (represents a portion of interest expense and loss on interest rate derivatives as reported on our Consolidated Statements of Operations).

(2) Gains on settlement of commodity contracts not designated as hedging instruments of $176 million (represents a portion of operating revenues and fuel and purchased energy expense as reported on our Consolidated Statements of Operations) and $27 million related to recognition of gains from cash flow hedges, previously reflected in OCI, partially offset by other changes in derivative assets and liabilities not reflected in OCI or net income.

(3) Net commodity and interest rate derivative assets and liabilities reported in Notes 7 and 8 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 following tables detail the components of our total mark-to-market activity for both the net realized gain (loss) and the net unrealized gain (loss) recognized from our derivative instruments in earnings and where these components were recorded on our Consolidated Statements of Operations for the years ended December 31, 2011, 2010 and 2009 (in millions):

	2011	2010	2009
Realized gain (loss)			
Interest rate swaps	$ (193)	$ (31)	$ (32)
Commodity derivative instruments	143	114	37
Total realized gain (loss)	$ (50)	$ 83	$ 5
Unrealized gain (loss)[1]			
Interest rate swaps	$ 55	$ (199)	$ 8
Commodity derivative instruments	(25)	143	79
Total unrealized gain (loss)	$ 30	$ (56)	$ 87
Total mark-to-market activity, net	$ (20)	$ 27	$ 92

(1) In addition to changes in market value on derivatives not designated as hedges, changes in unrealized gain (loss) also includes de-designation of interest rate swap cash flow hedges and related reclassification from AOCI into income, hedge ineffectiveness and adjustments to reflect changes in credit default risk exposure.

	2011	2010	2009
Realized and unrealized gain (loss)			
Power contracts included in operating revenues	$ (20)	$ (19)	$ 7
Natural gas contracts included in fuel and purchased energy expense	138	276	109
Interest rate swaps included in interest expense	7	(7)	(24)
Loss on interest rate derivatives	(145)	(223)	—
Total mark-to-market activity, net	$ (20)	$ 27	$ 92

Our change in AOCI from an accumulated loss of $125 million at December 31, 2010, to an accumulated loss of $178 million at December 31, 2011, was primarily driven by a decrease in longer-term LIBOR rates which negatively impacted our project debt interest rate swaps by $148 million, inclusive of intraperiod losses throughout 2011 on project debt interest rate swaps settling in 2011, and $163 million associated with gains on settlement of commodity derivative cash flow hedges reclassified into net income, inclusive of the unfavorable impact from reclassification into net income of intraperiod gains throughout 2011 on commodity derivative cash flow hedges settling in 2011. These negative factors were partially offset by $47 million in losses on settlement of interest rate swap cash flow hedges reclassified into net income, inclusive of the favorable impact from reclassification into net income of intraperiod losses throughout 2011 on project debt interest rate swaps settling in 2011, a reclassification adjustment of $91 million for cash flow hedges formerly hedging the First Lien Credit Facility term loans realized in net income, gains of $86 million on existing commodity derivative cash flow hedges, inclusive of intraperiod gains throughout 2011 on commodity derivative cash flow hedges settling in 2011, and the effect of income taxes, which includes a net $45 million increase to tax benefit in OCI with a partial offsetting expense to continuing operations related to the intraperiod tax allocation provisions under U.S. GAAP.

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 and non-derivative instruments.

The net fair value of outstanding derivative commodity instruments at December 31, 2011, based on price source and the period during which the instruments will mature, are summarized in the table below (in millions):

Fair Value Source	2012	2013-2014	2015-2016	After 2016	Total
Prices actively quoted	$ 58	$ (48)	$ —	$ —	$ 10
Prices provided by other external sources	11	16	—	—	27
Prices based on models and other valuation methods	5	9	—	—	14
Total fair value	$ 74	$ (23)	$ —	$ —	$ 51

We measure the energy commodity price risks in our portfolio on a daily basis using a VAR model to estimate the maximum potential one-day risk of loss based upon historical experience resulting from market movements in comparison to internally established thresholds. Our VAR is calculated for our entire portfolio which is comprised of energy 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, exclusive of the current month of measurement, 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 years ended December 31, 2011 and 2010 (in millions):

	2011	2010
Year ended December 31:		
High	$ 56	$ 58
Low	$ 20	$ 20
Average	$ 33	$ 30
As of December 31	$ 41	$ 37

Due to the inherent limitations of statistical measures such as VAR, the VAR calculation may not capture the full extent of our commodity price exposure. As a result, actual changes in the value of our energy commodity portfolio could be different from the calculated VAR, and the actual changes could have a material impact on our financial results. In order to evaluate the risks of our portfolio on a comprehensive basis and augment our VAR analysis, we also measure the risk of the energy commodity portfolio using several analytical methods including sensitivity tests, scenario tests, stress tests, and daily position reports.

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 9 of the Notes to Consolidated Financial Statements.

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

- credit approvals;
- routine monitoring of counterparties' credit limits and their overall credit ratings;
- limiting our marketing, hedging and optimization activities with high risk counterparties;
- margin, collateral, or prepayment arrangements; and

- payment netting arrangements, or master netting arrangements that allow for the netting of positive and negative exposures of various contracts associated with a single counterparty.

We have concentrations of credit risk with a few of our commercial customers relating to our sales of power, steam and hedging and optimization activities. We believe that our credit policies and portfolio of transactions adequately monitor and diversify our credit risk, and currently our counterparties are performing and financially settling timely according to their respective agreements. 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 an executory contract, 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, 2011, 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, 2011)	2012	2013-2014	2015-2016	After 2016	Total
Investment grade	$ 95	$ (23)	$ —	$ —	$ 72
Non-investment grade	(13)	—	—	—	(13)
No external ratings	(8)	—	—	—	(8)
Total fair value	$ 74	$ (23)	$ —	$ —	$ 51

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.

The following table summarizes the contract terms as well as the fair values of our debt instruments exposed to interest rate risk as of December 31, 2011. All outstanding balances and fair market values are shown gross of applicable premium or discount, if any (in millions):

	2012	2013	2014	2015	2016	Thereafter	Total	Fair Value December 31, 2011
Debt by Maturity Date:								
Fixed Rate	$ 21	$ 24	$ 21	$ 6	$ 1,007	$ 5,968	$ 7,047	$ 7,439
Average Interest Rate	9.6%	9.6%	9.4%	6.5%	8.0%	7.6%		
Variable Rate	$ 40	$ 70	$ 340	$ 126	$ 131	$ 2,294	$ 3,001	$ 2,932
Average Interest Rate[(1)]	3.9%	3.5%	6.0%	3.5%	3.7%	5.3%		

(1) Projection based upon anticipated LIBOR rates.

Our variable rate financings are indexed to base rates, generally LIBOR. Interest rate risk represents the potential loss in earnings arising from adverse changes in market interest rates. The fair value of our interest rate swaps are validated based upon external quotes. Our interest rate swaps are with counterparties we believe are primarily high quality institutions, and we do not believe that our interest rate swaps expose us to any significant credit risk. Holding all other factors constant, we estimate that a 10% decrease in interest rates would result in a change in the fair value of our interest rate swaps formerly hedging our First Lien Credit Facility of approximately $(3) million, and would result in a change in the fair value of our interest rate swaps hedging our other variable rate debt of approximately $(16) million at December 31, 2011.

APPLICATION OF CRITICAL ACCOUNTING POLICIES

The preparation of financial statements in accordance with U.S. 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

We routinely enter into physical commodity contracts for sales of our generated power to manage risk and capture the

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

During 2010, we repaid approximately $3.5 billion of our First Lien Credit Facility term loans, which had approximately $3.3 billion notional amount of interest rate swaps hedging the scheduled variable interest payments, and in January 2011, we repaid the remaining approximately $1.2 billion of First Lien Credit Facility term loans which had approximately $1.0 billion notional amount of interest rate swaps hedging the scheduled variable interest payments. With the repayment of the remaining First Lien Credit Facility term loans, the remaining unrealized losses of approximately $91 million in AOCI related to the interest rate swaps formerly hedging the First Lien Credit Facility, were reclassified out of AOCI and into income as an additional loss on interest rate derivatives during 2011. In addition, we reclassified approximately $17 million in unrealized losses in AOCI to loss on interest rate derivatives during 2011 resulting from the repayment of project debt in 2011. During 2010, we reclassified approximately $206 million out of AOCI and into income as additional loss on interest rate derivatives related to interest rate swaps formerly hedging our First Lien Credit Facility term loans. We have presented the reclassification of unrealized losses from AOCI into income and the changes in fair value and settlements subsequent to the reclassification date of the interest rate swaps formerly hedging our First Lien Credit Facility described above separate from interest expense as loss on interest rate derivatives on our Consolidated Statements of Operations. We also have determined that, based upon current market conditions and consistent with our Risk Management Policy, liquidation of these interest rate swaps is not economically beneficial and additional future losses are limited. Accordingly, we have elected to retain and hold these interest rate swap positions at this time. The interest rate swaps formerly hedging our First Lien Credit Facility term loans substantially mature in 2012.

See Notes 7 and 8 of the Notes to Consolidated Financial Statements for further discussion of our derivative instruments and our interest rate swaps formerly hedging our First Lien Credit Facility term loans.

Accounting for VIEs and Financial Statement Consolidation Criteria

We consolidate all VIEs where we have determined that we are the primary beneficiary and where we determine that we have both the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses or receive benefits from the VIE. We have determined that we hold the obligation to absorb losses and receive benefits in all of our VIEs where we hold the majority equity interest. Therefore, our determination of whether to consolidate is based upon which variable interest holder has the power to direct the most significant activities of the VIE (the primary beneficiary). Our analysis includes consideration of the following primary activities which we believe to have a significant impact on a power plant's financial performance: operations and maintenance, plant dispatch, and fuel strategy as well as our ability to control or influence contracting and overall plant strategy. Our approach to determining which entity holds the powers and rights is based on powers held as of the balance sheet date. Contractual terms that may change the powers held in future periods, such as a purchase or sale option, are not considered in our analysis. Based on our analysis, we believe that we hold the power and rights to direct the most significant activities of all our majority owned VIEs.

Under our consolidation policy and under U.S. GAAP we also:

- perform an ongoing reassessment each reporting period of whether we are the primary beneficiary of our VIEs; and
- evaluate if an entity is a VIE and whether we are the primary beneficiary whenever any changes in facts and circumstances occur such that the holders of the equity investment at risk, as a group, lose the power from voting rights or similar rights of those investments to direct the activities of a VIE that most significantly impact the VIE's economic performance or when there are other changes in the powers held by individual variable interest holders.

Because we are required to perform ongoing reassessments of whether we are the primary beneficiary, future changes in our assessments of whether we are the primary beneficiary could require us to consolidate our VIEs that are currently not consolidated or deconsolidate our VIEs that are currently consolidated based upon our reassessments in future periods. Making these determinations can require the use of significant judgment to determine which variable interest holder has the power to direct the most significant activities of the VIE (the primary beneficiary) and can directly impact amounts reported on our Consolidated Financial Statements.

Noncontrolling Interest — We own a 75% interest in Russell City Energy Company, LLC, one of our VIEs, which is also 25% owned by a third party. We fully consolidate this entity in our Consolidated Financial Statements and account for the third party ownership interest as a noncontrolling interest under U.S. GAAP.

Disclosure Requirements

U.S. GAAP requires separate disclosure on the face of our Consolidated Balance Sheets of the significant assets of a consolidated VIE that can only be used to settle obligations of the consolidated VIE and the significant liabilities of a consolidated VIE for which creditors (or beneficial interest holders) do not have recourse to the general credit of the primary beneficiary. In determining which assets of our VIEs met the separate disclosure criteria, we determined this separate disclosure requirement is met where Calpine Corporation is substantially limited or prohibited from access to assets (primarily cash and cash equivalents, restricted cash and property, plant and equipment), and where there are agreements that prohibit the debt holders of the VIE from recourse to the general credit of Calpine Corporation. In determining which liabilities of our VIEs met the separate disclosure criteria, we reviewed all of our VIEs and determined this separate disclosure requirement was met where our VIEs had project financing that prohibits the VIE from providing guarantees on the debt of others and where the amounts were material to our financial statements.

Unconsolidated VIEs

We have a 50% partnership interest in Greenfield LP and in Whitby. Greenfield LP and Whitby are also VIEs; however, we do not have the power to direct the most significant activities of these entities and therefore do not consolidate them. We account for these entities under the equity method of accounting and include our net equity interest in investments on our Consolidated Balance Sheets. During 2009, we were not the primary beneficiary of OMEC based upon the accounting guidance in 2009, and did not consolidate OMEC. Our equity interest in the net income from OMEC for the year ended December 31, 2009, and both Greenfield LP and Whitby for the years ended December 31, 2011, 2010 and 2009 are recorded in (income) from unconsolidated investments in power plants. As required by U.S. GAAP, we consolidated OMEC effective January 1, 2010.

We hold a call option to purchase the Inland Empire Energy Center (a 775 MW natural gas-fired power plant located in California which achieved COD on May 3, 2010) from GE that may be exercised between years 7 and 14 after the start of commercial operation. GE holds a put option whereby they can require us to purchase the power plant, if certain plant performance criteria are met during year 15 after the start of commercial operation. We determined that we were not the primary beneficiary of the Inland Empire power plant, and we do not consolidate it due to, but not limited to, the fact that GE directs the most significant activities of the power plant including operations and maintenance.

Long Lived Assets and Depreciation Expense

Determination of the appropriate depreciation method, proper useful lives and salvage values involves significant judgment, estimates, assumptions and historical experience. Changes in our estimates and methods can result in a significant impact in the amounts and timing of when we recognize depreciation expense and therefore significantly impact our financial condition and results of operations from period to period. Different depreciation methods can impact the timing and amount of depreciation expense affecting our results of operations and could result in different net book values of assets at a particular time during the useful life of the asset affecting our financial position. Estimates of useful lives also significantly impact the timing and amounts of depreciation expense and include significant estimates. If useful lives are too short, then the asset is depreciated too quickly and depreciation expense is overstated. Estimated useful lives can significantly decrease if routine maintenance or certain upgrades are not performed, premature mechanical failure of the asset occurs, significant increases in the planned level of usage occur, advances in technology make the asset obsolete, or if there are adverse changes in environmental regulations. Our depreciable cost basis of our assets are reduced by their estimated salvage values. Estimates involved with salvage values include future estimated costs of dismantlement and repair, market prices, environmental regulations and technological advancements. Dependent upon our ability to accurately estimate salvage values and the timing of disposal, the salvage values actually realized for our assets could significantly increase or decrease resulting in additional gains or losses in the year of disposal.

We depreciate our assets under the straight line method over the shorter of their estimated useful lives or lease term using an estimated salvage value which approximates 10% of the depreciable cost basis for our power plant assets where we own the land or have a favorable option to purchase the land at conclusion of the lease term and approximately 0.15% of the depreciable costs basis for our rotable equipment. We use component depreciation method for our rotable parts and composite depreciation method for all the other power plant asset groups and Geysers Assets. During 2009, we reviewed our accounting policies related to depreciation including our estimates of useful lives and salvage values. We determined changing from composite depreciation to component depreciation for our rotable natural gas-fired power plant assets, and changing our Geysers Assets depreciation from the units of production method to the straight line method was preferable under U.S. GAAP. In addition, we completed a depreciable life study of our natural gas-fired power plants and Geysers Assets and determined that a change in the depreciable lives of our natural gas-fired power plants and Geysers Assets was appropriate. See Note 4 of the Notes to Consolidated Financial Statements for further discussion regarding our changes in depreciation.

Impairments

We evaluate our long-lived assets, such as property, plant and equipment, equity method investments, turbine equipment and specifically identified intangibles, on an annual basis or 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. 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 loss. Significant judgment is required in determining fair value as discussed above in "— *Fair Value Measurements*." Equipment assigned to each power plant is not evaluated for impairment separately; instead, we evaluate our operating power plants and related equipment as a whole unit.

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 their fair 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.

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 and estimates are 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.

For federal income tax reporting purposes, our historical tax reporting group was comprised primarily of two separate groups, CCFC and its subsidiaries, which we referred to as the CCFC group, and Calpine Corporation and its subsidiaries other than CCFC, which we referred to as the Calpine group. During the first quarter of 2011, we elected to consolidate our CCFC and Calpine groups for federal income tax reporting purposes and Calpine will file a consolidated federal income tax return for the year ended December 31, 2011 that will include the CCFC group. As a result of the consolidation, the CCFC group deferred tax liabilities will be eligible to offset existing Calpine group NOLs that were reserved by a valuation allowance. Accordingly, we recorded a one-time federal deferred income tax benefit of approximately $76 million during the first quarter of 2011 to reduce our valuation allowance. For the years ended December 31, 2010 and 2009, the CCFC group was deconsolidated from the Calpine group for federal income tax reporting purposes. See Note 10 of the Notes to Consolidated Financial Statements for additional discussion of our Calpine and CCFC groups.

Our NOL carryforwards consist primarily of federal NOL carryforwards of approximately $7.9 billion, which expire between 2023 and 2031, and NOL carryforwards in 33 states and the District of Columbia totaling approximately $4.2 billion, which expire between 2012 and 2032, substantially all of which are offset with a full valuation allowance. We also have approximately $1.0 billion in foreign NOLs, substantially all of which are offset with a full valuation allowance. The NOL carryforwards available are subject to limitations on their annual usage. 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. Under federal income tax law, our NOL carryforwards can be

utilized to reduce future taxable income subject to certain limitations, including if we were to undergo an ownership change as defined by Section 382 of 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 our Plan of Reorganization. However, this ownership change and the resulting annual limitations are not expected to result in the expiration of our NOL carryforwards if we are able to generate sufficient future taxable income within the carryforward periods. At December 31, 2011, approximately $2.4 billion of our $7.9 billion federal NOLs are not subject to annual Section 382 limitations. When considering our cumulative annual Section 382 limitations, in addition to our post-Effective Date NOLs that are not limited, our total unrestricted NOLs are approximately $6.3 billion. If a subsequent ownership change were to occur as a result of future transactions in our common 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.

Under state income tax laws, our NOL carryforwards can be utilized to reduce future taxable income subject to certain limitations, including if we were to undergo an ownership change as defined by Section 382 of the IRC. During 2011, we analyzed the effect of our change in ownership on the Effective Date for each of our significant states to determine the amount of our NOL limitation. The analysis determined that $640 million of our state NOLs are expected to expire unutilized as a result of statutory limitations on the use of some of our pre-emergence state NOLs as of the Effective Date or the cessation of business operations in various tax jurisdictions. We reduced our deferred tax asset for state NOLs that we are unable to utilize and made an equal reduction in our valuation allowance. The result did not have an impact on our income tax expense in 2011. In 2012 we will continue with our analysis and adjust our state NOLs where appropriate.

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 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. 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, 2011, we had $74 million of unrecognized tax benefits from uncertain tax positions.

See Note 10 of the Notes to Consolidated Financial Statements for further discussion of our accounting for income taxes.

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 Statements of Operations,” “Consolidated Statements of Comprehensive Income (Loss)," “Consolidated Balance Sheets,” “Consolidated Statements of Stockholders’ Equity,” “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 as defined in Rule 13a-15(e) or Rule 15d-15(e) 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 such that the information required to be disclosed in our SEC reports is recorded, processed, summarized and reported within the time periods specified in SEC rules and forms, and is accumulated and communicated to our management, including our Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosure.

Management's Report on Internal Control over Financial Reporting

Our management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act). 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 U.S. GAAP.

Our internal control over financial reporting includes those policies and procedures that:

- pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of our assets;
- provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with U.S. GAAP, and that our receipts and expenditures are being made only in accordance with authorizations of our management and directors; and
- provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of our assets that could have a material effect on our financial statements.

Management has assessed the effectiveness of our internal control over financial reporting as of December 31, 2011. 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, management has concluded that our internal control over financial reporting was effective as of December 31, 2011 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of consolidated financial statements for external reporting purposes in accordance with U.S. GAAP.

The effectiveness of our internal control over financial reporting as of December 31, 2011, 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 2011, there were no changes in our internal control over financial reporting (as defined in Rules 13a-15(f) and 15d-15(f) under the Exchange Act) 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, Executive Officers and Corporate Governance*

Identification of Executive Officers

Set forth in the table below is a list of our executive officers, together with certain biographical information, including their ages as of the date of this Report:

Name	Age	Principal Occupation
Jack A. Fusco	49	President and Chief Executive Officer
John B. Hill	44	Executive Vice President and Chief Operating Officer
Zamir Rauf	52	Executive Vice President and Chief Financial Officer
W. Thaddeus Miller	61	Executive Vice President, Chief Legal Officer and Secretary
Jim D. Deidiker	56	Senior Vice President and Chief Accounting Officer
Gary M. Germeroth	53	Executive Vice President and Chief Risk Officer

Jack A. Fusco has served as our President and Chief Executive Officer and as a member of our Board of Directors since August 10, 2008. From July 2004 to February 2006, Mr. Fusco served as the Chairman and Chief Executive Officer of Texas Genco LLC. From 2002 through July 2004, Mr. Fusco was an exclusive energy investment advisor for Texas Pacific Group. From November 1998 until February 2002, he served as President and Chief Executive Officer of Orion Power Holdings, Inc. Prior to his founding of Orion Power Holdings, Inc., Mr. Fusco was a Vice President at Goldman Sachs Power, an affiliate of Goldman, Sachs & Co. Prior to joining Goldman Sachs, Mr. Fusco was employed by Pacific Gas and Electric Company or its affiliates in various engineering and management roles for approximately 13 years. Mr. Fusco obtained a Bachelor of Science degree in Mechanical Engineering from California State University, Sacramento. Mr. Fusco served as a director of Foster Wheeler Ltd., a global engineering and construction contractor and power equipment supplier, until February 2009 and Graphics Packaging Holdings, a paper and packaging company, until 2008.

John B. (Thad) Hill has served as our Executive Vice President and Chief Operating Officer since November 3, 2010 and served as the Company's Executive Vice President and Chief Commercial Officer since joining the Company on September 1, 2008. Prior to joining the Company, Mr. Hill most recently served as Executive Vice President of NRG Energy, Inc. since February 2006 and President of NRG Texas LLC since December 2006. Prior to joining NRG Energy, Inc., Mr. Hill was Executive Vice President of Strategy and Business Development at Texas Genco LLC from 2005 to 2006. From 1995 to 2005, Mr. Hill was with Boston Consulting Group, Inc., where he rose to Partner and Managing Director and led the North American energy practice, serving companies in the power and gas sector with a focus on commercial and strategic issues. Mr. Hill received his Bachelor of Arts degree from Vanderbilt University and a Master of Business Administration degree from the Amos Tuck School of Dartmouth College.

Zamir Rauf has served as our Executive Vice President and Chief Financial Officer since December 17, 2008, after serving as Interim Chief Financial Officer from June 4, 2008. Previously, he served as our Senior Vice President, Finance and Treasurer from September 2007 until his appointment as Interim Chief Financial Officer. Since joining the Company in February 2000, Mr. Rauf has served as Manager, Finance from February 2000 to April 2001, Director, Finance from April 2001 to December 2002, Vice President, Finance from December 2002 to July 2005 and Senior Vice President, Finance from July 2005 to September 2007. Prior to joining the Company, Mr. Rauf held various accounting and finance roles with Enron North America and Dynegy Inc., as well as credit and lending roles with Comerica Bank. Mr. Rauf earned his Bachelor of Arts degree in Business and Commerce and Masters in Business Administration – Finance degree from the University of Houston.

W. Thaddeus Miller has served as our Executive Vice President, Chief Legal Officer and Secretary since August 12, 2008. Prior to joining the Company, Mr. Miller most recently served as Executive Vice President and Chief Legal Officer of Texas Genco LLC from December 14, 2004 until 2006. From 2002 to 2004, Mr. Miller was a consultant to Texas Pacific Group, a private equity firm. From 1999 to 2002, he served as Executive Vice President and Chief Legal Officer of Orion Power Holdings, Inc., an independent power producer. From 1994 to 1999, Mr. Miller was a Vice President of Goldman Sachs & Co., where he focused on wholesale electric and other energy commodity trading. Before joining Goldman Sachs & Co., Mr. Miller was a partner in a New York law firm. Mr. Miller earned his Bachelor of Science degree from the U.S. Merchant Marine Academy and his Juris Doctor degree from St. John's School of Law. In addition, Mr. Miller was an officer in the U.S. Coast Guard from 1973 through 1976.

Jim D. Deidiker has served as our Senior Vice President and Chief Accounting Officer since November 15, 2010. Mr. Deidiker served as the Company's Senior Vice President and Chief Accounting Officer since joining the Company in January 2008 until May 2010, when he resigned as the Company's Chief Accounting Officer due to health concerns, but remained an employee. Mr. Deidiker returned to his role as the Company's Senior Vice President and Chief Accounting Officer once his health concerns were resolved. Prior to joining the Company, Mr. Deidiker most recently served as Vice President and Controller of Texas Genco LLC from 2005 to 2006 where he was responsible for financial and public reporting as well as management of the accounting function. From 1998 to 2005, Mr. Deidiker served as Managing Director & Vice President, Administration of AEP Energy Services, Inc. where he was responsible for management of the accounting function, financial reporting, contract administration and risk management for the gas pipeline and trading segment of AEP Energy Services, Inc. Mr. Deidiker obtained a Bachelor of Science degree in Accounting from Missouri State University and a Master in Business Administration degree from the University of Houston. In addition, Mr. Deidiker is a Certified Public Accountant and Certified Management Accountant.

Gary M. Germeroth has served as our Executive Vice President and Chief Risk Officer since June 2007. Mr. Germeroth's responsibilities include maintaining oversight of our risk management framework and assuring that our complex risks are communicated and understood throughout the organization. Prior to joining the Company, Mr. Germeroth worked for PA Consulting Group, Inc. and its predecessor firm, Hagler Bailly Risk Advisors, since 1999. Prior to joining PA Consulting, Mr. Germeroth held a variety of controllership, risk control and treasury positions at various entities in his energy career. Mr. Germeroth has more than 30 years of experience in energy strategy and risk management, having directed a variety of commercial strategy, enterprise risk management and corporate restructuring projects for multiple companies. Mr. Germeroth has led efforts related to corporate governance, portfolio risk evaluation, operational risk management, strategic options analysis, management of portfolio capital requirements, organizational and business process design, transaction settlement and financial accounting. Mr. Germeroth obtained a Bachelor of Science degree in Finance from the University of Denver.

The remaining information required by this Item under the captions "Board Meeting and Board Committee Information," "Corporate Governance Matters" and "Proposal 1 — Election of Directors" is incorporated herein by reference to our proxy statement for the 2012 annual meeting of stockholders to be held on May 15, 2012.

Item 11. ***Executive Compensation***

Information required by this Item is incorporated herein by reference to our proxy statement for the 2012 annual meeting of stockholders to be held May 15, 2012.

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

Information required by this Item is incorporated herein by reference to our proxy statement for the 2012 annual meeting of stockholders to be held May 15, 2012.

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

Information required by this Item is incorporated herein by reference to our proxy statement for the 2012 annual meeting of stockholders to be held May 15, 2012.

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

Information required by this Item is incorporated herein by reference to our proxy statement for the 2012 annual meeting of stockholders to be held May 15, 2012.

PART IV

Item 15. ***Exhibits, Financial Statement Schedule***

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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 Calpine'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 Calpine's Current Report on Form 8-K filed with the SEC on December 27, 2007).
2.3	Purchase and Sale Agreement by and between Riverside Energy Center, LLC and Calpine Development Holdings, Inc., as Sellers and Public Service Company of Colorado, as Purchaser dated as of April 2, 2010 (incorporated by reference to Exhibit 10.1 to Calpine's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, filed with the SEC on July 29, 2010).**,††
2.4	Purchase Agreement by and among Pepco Holdings, Inc., Conectiv, LLC, Conectiv Energy Holding Company, LLC and New Development Holdings, LLC dated as of April 20, 2010 (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K, filed with the SEC on July 8, 2010).**
3.1	Amended and Restated Certificate of Incorporation of the Company, as amended (incorporated by reference to Exhibit 3.1 to Calpine'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 (as amended through May 7, 2009) (incorporated by reference to Exhibit 3.2 to Calpine's Quarterly Report on Form 10-Q for the quarter ended June 30, 2009, filed with the SEC on July 31, 2009).
4.1	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 4.00% senior secured notes due 2011 (incorporated by reference to Exhibit 4.6 to Calpine's Quarterly Report on Form 10-Q for the quarter ended September 30, 2003, filed with the SEC on November 13, 2003).
4.2	Indenture, dated May 19, 2009, among Calpine Construction Finance Company, L.P. and CCFC Finance Corp., the guarantors named therein, and Wilmington Trust Company, as trustee, including form of 8.00% senior secured notes due 2016 (incorporated by reference to Exhibit 4.1 to Calpine's Current Report on Form 8-K filed with the SEC on May 22, 2009).
4.3	Indenture, dated October 21, 2009, between the Company and Wilmington Trust Company, as trustee, including form of 7.25% senior secured notes due 2017 (incorporated by reference to Exhibit 4.1 to Calpine's Current Report on Form 8-K filed with the SEC on October 26, 2009).
4.4	Amended and Restated Indenture, dated May 25, 2010, among Calpine Corporation, the guarantors party thereto and Wilmington Trust Company, as trustee, including the form of the 8% Senior Secured Notes due 2019 (incorporated by reference to Exhibit 4.1 to Calpine's Current Report on Form 8-K filed with the SEC on May 25, 2010).
4.5	Indenture, dated July 23, 2010, among Calpine Corporation, the guarantors party thereto and Wilmington Trust Company, as trustee, including the form of the 7.875% Senior Secured Notes due 2020 (incorporated by reference to Exhibit 4.1 to Calpine's Current Report on Form 8-K filed with the SEC on July 23, 2010).

Exhibit Number	Description
4.6	Indenture, dated October 22, 2010, among Calpine Corporation, the guarantors party thereto and Wilmington Trust Company, as trustee, including the form of the 7.50% Senior Secured Notes due 2021 (incorporated by reference to Exhibit 4.1 to Calpine's Current Report on Form 8-K filed with the SEC on October 22, 2010).
4.7	Indenture, dated January 14, 2011, among Calpine Corporation, the guarantors party thereto and Wilmington Trust Company, as trustee, including the form of the 7.875% Senior Secured Notes due 2023 (incorporated by reference to Exhibit 4.1 to Calpine's Current Report on Form 8-K filed with the SEC on January 14 , 2011).
4.8	Registration Rights Agreement, dated January 31, 2008, among the Company and each Participating Shareholder named therein (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K filed with the SEC on February 6, 2008).
4.9	First Supplemental Indenture dated as of April 26, 2011, among each of New Development Holdings, LLC, Calpine Mid-Atlantic Energy, LLC, Calpine Mid-Atlantic Operating, LLC, Calpine Bethlehem, LLC, Calpine New Jersey Generation, LLC, Calpine Mid-Atlantic Generation, LLC, Calpine Solar, LLC, Calpine Vineland Solar, LLC and Calpine Mid-Atlantic Marketing, LLC and Wilmington Trust Company, as trustee under the indenture, dated as of October 21, 2009, providing for the issuance of 7.25% Senior Secured Notes due 2017 (incorporated by reference to Exhibit 4.2 to Calpine's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011, filed with the SEC on April 28, 2011).
4.10	First Supplemental Indenture dated as of April 26, 2011, among each of New Development Holdings, LLC, Calpine Mid-Atlantic Energy, LLC, Calpine Mid-Atlantic Operating, LLC, Calpine Bethlehem, LLC, Calpine New Jersey Generation, LLC, Calpine Mid-Atlantic Generation, LLC, Calpine Solar, LLC, Calpine Vineland Solar, LLC and Calpine Mid-Atlantic Marketing, LLC and Wilmington Trust Company, as trustee under the indenture, dated as of May 25, 2010, providing for the issuance of 8.0% Senior Secured Notes due 2019 (incorporated by reference to Exhibit 4.3 to Calpine's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011, filed with the SEC on April 28, 2011).
4.11	First Supplemental Indenture dated as of April 26, 2011, among each of New Development Holdings, LLC, Calpine Mid-Atlantic Energy, LLC, Calpine Mid-Atlantic Operating, LLC, Calpine Bethlehem, LLC, Calpine New Jersey Generation, LLC, Calpine Mid-Atlantic Generation, LLC, Calpine Solar, LLC, Calpine Vineland Solar, LLC and Calpine Mid-Atlantic Marketing, LLC and Wilmington Trust Company, as trustee under the indenture, dated as of July 23, 2010, providing for the issuance of 7.875% Senior Secured Notes due 2020 (incorporated by reference to Exhibit 4.4 to Calpine's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011, filed with the SEC on April 28, 2011).
4.12	First Supplemental Indenture dated as of April 26, 2011, among each of New Development Holdings, LLC, Calpine Mid-Atlantic Energy, LLC, Calpine Mid-Atlantic Operating, LLC, Calpine Bethlehem, LLC, Calpine New Jersey Generation, LLC, Calpine Mid-Atlantic Generation, LLC, Calpine Solar, LLC, Calpine Vineland Solar, LLC and Calpine Mid-Atlantic Marketing, LLC and Wilmington Trust Company, as trustee under the indenture, dated as of October 22, 2010, providing for the issuance of 7.50% Senior Secured Notes due 2021 (incorporated by reference to Exhibit 4.5 to Calpine's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011, filed with the SEC on April 28, 2011).
4.13	First Supplemental Indenture dated as of April 26, 2011, among each of New Development Holdings, LLC, Calpine Mid-Atlantic Energy, LLC, Calpine Mid-Atlantic Operating, LLC, Calpine Bethlehem, LLC, Calpine New Jersey Generation, LLC, Calpine Mid-Atlantic Generation, LLC, Calpine Solar, LLC, Calpine Vineland Solar, LLC and Calpine Mid-Atlantic Marketing, LLC and Wilmington Trust Company, as trustee under the indenture, dated as of January 14, 2011, providing for the issuance of 7.875% Senior Secured Notes due 2023 (incorporated by reference to Exhibit 4.6 to Calpine's Quarterly Report on Form 10-Q for the quarter ended March 31, 2011, filed with the SEC on April 28, 2011).

Exhibit Number	Description
4.14	Second Supplemental Indenture dated as of July 22, 2011, among each of Deer Park Energy Center LLC, Deer Park Holdings, LLC, Metcalf Energy Center, LLC, Metcalf Holdings, LLC and Wilmington Trust Company, as trustee under the indenture, dated as of October 21, 2009, providing for the issuance of 7.25% Senior Secured Notes due 2017 (incorporated by reference to Exhibit 4.1 to Calpine's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, filed with the SEC on July 28, 2011).
4.15	Second Supplemental Indenture dated as of July 22, 2011, among each of Deer Park Energy Center LLC, Deer Park Holdings, LLC, Metcalf Energy Center, LLC, Metcalf Holdings, LLC and Wilmington Trust Company, as trustee under the indenture, dated as of May 25, 2010, providing for the issuance of 8.0% Senior Secured Notes due 2019 (incorporated by reference to Exhibit 4.2 to Calpine's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, filed with the SEC on July 28, 2011).
4.16	Second Supplemental Indenture dated as of July 22, 2011, among each of Deer Park Energy Center LLC, Deer Park Holdings, LLC, Metcalf Energy Center, LLC, Metcalf Holdings, LLC and Wilmington Trust Company, as trustee under the indenture, dated as of July 23, 2010, providing for the issuance of 7.875% Senior Secured Notes due 2020 (incorporated by reference to Exhibit 4.3 to Calpine's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, filed with the SEC on July 28, 2011).
4.17	Second Supplemental Indenture dated as of July 22, 2011, among each of Deer Park Energy Center LLC, Deer Park Holdings, LLC, Metcalf Energy Center, LLC, Metcalf Holdings, LLC and Wilmington Trust Company, as trustee under the indenture, dated as of October 22, 2010, providing for the issuance of 7.50% Senior Secured Notes due 2021 (incorporated by reference to Exhibit 4.4 to Calpine's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, filed with the SEC on July 28, 2011).
4.18	Second Supplemental Indenture dated as of July 22, 2011, among each of Deer Park Energy Center LLC, Deer Park Holdings, LLC, Metcalf Energy Center, LLC, Metcalf Holdings, LLC and Wilmington Trust Company, as trustee under the indenture, dated as of January 14, 2011, providing for the issuance of 7.875% Senior Secured Notes due 2023 (incorporated by reference to Exhibit 4.5 to Calpine's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, filed with the SEC on July 28, 2011).
10.1	Financing Agreements.
10.1.1.5	Credit Agreement, dated as of December 10, 2010, among Calpine Corporation, Goldman Sachs Bank USA, as administrative agent, Goldman Sachs Credit Partners L.P., as collateral agent, the lenders party thereto and other parties thereto (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K filed with the SEC on December 13, 2010).
10.1.1.6	Credit Agreement, dated March 9, 2011 among Calpine Corporation as borrower and the lenders party hereto, and Morgan Stanley Senior Funding, Inc., as administrative agent, Goldman Sachs Credit Partners L.P., as collateral agent, Citibank, N.A., Credit Suisse Securities (USA) LLC and Deutsche Bank Securities Inc., as co-documentation agents and Goldman Sachs Bank USA as syndication agent (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K filed with the Securities and Exchange Commission on March 9, 2011).
10.1.1.7	Amended and Restated Guarantee and Collateral Agreement, dated as of December 10, 2010, 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 to Calpine's Quarterly Report on Form 10-Q for the quarter ended June 30, 2011, filed with the SEC on July 28, 2011).
10.2	Management-Contracts or Compensatory Plans or Arrangements.
10.2.1.1	Employment Agreement, dated August 10, 2008, between the Company and Jack A. Fusco (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K filed with the SEC on August 12, 2008).†

Exhibit Number	Description
10.2.1.2	Calpine Corporation Executive Sign On Non-Qualified Stock Option Agreement (Jack A. Fusco) (incorporated by reference to Exhibit 10.2 to Calpine's Current Report on Form 8-K filed with the SEC on August 12, 2008).†
10.2.1.3	Non-Qualified Stock Option Agreement between the Company and Jack Fusco, dated August 11, 2010 (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K filed with the SEC on August 17, 2010).†
10.2.2	Letter Agreement, dated December 17, 2008, between the Company and Zamir Rauf (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K filed with the SEC on December 19, 2008).†
10.2.3.1	Letter Agreement, dated September 1, 2008, between the Company and John B. Hill (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K filed with the SEC on September 4, 2008).†
10.2.3.2	Calpine Corporation Executive Sign On Non-Qualified Stock Option Agreement (John B. Hill) (incorporated by reference to Exhibit 10.2 to Calpine's Current Report on Form 8-K filed with the SEC on September 4, 2008).†
10.2.3.3	Non-Qualified Stock Option Agreement between the Company and John B. (Thad) Hill, dated August 11, 2010 (incorporated by reference to Exhibit 10.2 to Calpine's Current Report on Form 8-K filed with the SEC on August 17, 2010).†
10.2.3.4	Non-Qualified Stock Option Agreement between the Company and John B. (Thad) Hill, dated November 3, 2010 (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K filed with the SEC on November 5, 2010).†
10.2.4.1	Employment Agreement, dated August 11, 2008, between the Company and W. Thaddeus Miller (incorporated by reference to Exhibit 10.2.7 to Calpine's Quarterly Report on Form 10-Q for the quarter ended September 30, 2008, filed with the SEC on November 7, 2008).†
10.2.4.2	Calpine Corporation Executive Sign On Non-Qualified Stock Option Agreement (Thaddeus Miller) (incorporated by reference to Exhibit 4.4 to Calpine's Registration Statement on Form S-8 (Registration No. 333-153860) filed with the SEC on October 6, 2008).†
10.2.4.3	Non-Qualified Stock Option Agreement between the Company and W. Thaddeus Miller, dated August 11, 2010 (incorporated by reference to Exhibit 10.3 to Calpine's Current Report on Form 8-K filed with the SEC on August 17, 2010).†
10.2.5	Calpine Corporation U.S. Severance Program.†
10.2.6	Calpine Corporation 2010 Calpine Incentive Plan (incorporated by reference to Exhibit 10.6 to Calpine's Quarterly Report on Form 10-Q for the quarter ended June 30, 2010, filed with the SEC on July 29, 2010).†
10.2.7	Calpine Corporation 2009 Calpine Incentive Plan (incorporated by reference to Exhibit 10.2 to Calpine's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, filed with the SEC on May 8, 2009).†
10.2.7.1	The Amended and Restated Calpine Corporation 2008 Equity Incentive Plan (incorporated by reference to Exhibit 10.2 to Calpine's Current Report on Form 8-K filed with the SEC on November 5, 2010).†

Exhibit Number	Description
10.2.7.2	Form of Non-Qualified Stock Option Agreement (Pursuant to the 2008 Equity Incentive Plan) (incorporated by reference to Exhibit 10.4.3 to Calpine's Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, filed with the SEC on May 12, 2008).†
10.2.7.3	Form of Restricted Stock Agreement (Pursuant to the 2008 Equity Incentive Plan) (incorporated by reference to Exhibit 10.4.4 to Calpine's Quarterly Report on Form 10-Q for the quarter ended March 31, 2008, filed with the SEC on May 12, 2008).†
10.2.8	The Amended and Restated Calpine Corporation 2008 Director Incentive Plan (incorporated by reference to Appendix A to Calpine's Definitive Proxy Statement on Schedule 14A filed with the SEC on April 5, 2010).†
10.2.9	Calpine Corporation Change in Control and Severance Benefits Plan (incorporated by reference to Exhibit 10.2.10 to Calpine's Annual Report on Form 10-K for the year ended December 31, 2009, filed with the SEC on February 25, 2010).†
10.2.10	Letter Agreement, dated December 30, 2008, between the Company and Jim D. Deidiker (incorporated by reference to Exhibit 10.1 to Calpine's Current Report on Form 8-K fled with the SEC on January 8, 2009).†
10.2.11	Letter re Employment Offer, dated February 6, 2009, between the Company and Michael D. Rogers (incorporated by reference to Exhibit 10.1 to Calpine's Quarterly Report on Form 10-Q for the quarter ended March 31, 2009, filed with the SEC on May 7, 2009).†
18.1	Letter of preferability regarding change in accounting principle from PricewaterhouseCoopers LLP, Independent Registered Public Accounting Firm (incorporated by reference to Exhibit 18.1 to Calpine's Annual Report on Form 10-K for the year ended December 31, 2009 filed with the SEC on February 25, 2010).
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 Form 10-K).*
31.1	Certification of the Chief Executive Officer Pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.*
31.2	Certification of the Chief Financial Officer 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.‡
101.INS	XBRL Instance Document. ***
101.SCH	XBRL Taxonomy Extension Schema. ***
101.CAL	XBRL Taxonomy Extension Calculation Linkbase. ***
101.DEF	XBRL Taxonomy Extension Definition Linkbase. ***
101.LAB	XBRL Taxonomy Extension Label Linkbase. ***

Exhibit Number	Description
101.PRE	XBRL Taxonomy Extension Presentation Linkbase. ***

_____

* Filed herewith.

‡ Furnished herewith.

† Management contract or compensatory plan or arrangement.

** Schedules omitted pursuant to Item 601(b)(2) of Regulation S-K. Calpine will furnish supplementally a copy of any omitted schedule to the SEC upon request.

†† Portions of this exhibit have been omitted pursuant to a request for confidential treatment under Rule 24b-2 under the Securities Exchange Act of 1934.

*** XBRL (eXtensible Business Reporting Language) information is furnished, not filed or part of a registration statement or prospectus for purposes of Sections 11 or 12 of the Securities Act of 1933, as amended, is deemed not filed for purposes of Section 18 of the Securities and Exchange Act of 1934, as amended, and otherwise is not subject to liability under those sections.

SIGNATURES

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

CALPINE CORPORATION

By: /s/ ZAMIR RAUF

Zamir Rauf
Executive Vice President and Chief Financial Officer

Date: February 9, 2012

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 9, 2012
/s/ ZAMIR RAUF Zamir Rauf	Executive Vice President and Chief Financial Officer (principal financial officer)	February 9, 2012
/s/ JIM D. DEIDIKER Jim D. Deidiker	Chief Accounting Officer (principal accounting officer)	February 9, 2012
/s/ FRANK CASSIDY Frank Cassidy	Director	February 9, 2012
/s/ ROBERT C. HINCKLEY Robert C. Hinckley	Director	February 9, 2012
/s/ DAVID C. MERRITT David C. Merritt	Director	February 9, 2012
/s/ W. BENJAMIN MORELAND W. Benjamin Moreland	Director	February 9, 2012
/s/ ROBERT MOSBACHER, JR. Robert Mosbacher, Jr.	Director	February 9, 2012
/s/ DENISE M. O'LEARY Denise M. O'Leary	Director	February 9, 2012
/s/ WILLIAM E. OBERNDORF William E. Oberndorf	Director	February 9, 2012
/s/ J. STUART RYAN J. Stuart Ryan	Director	February 9, 2012

CALPINE CORPORATION AND SUBSIDIARIES

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December 31, 2011

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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, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011 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 Item 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, 2011, 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, 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 described in Note 5 to the consolidated financial statements, the Company changed the manner in which it accounts for variable interest entities in 2010. As described in Note 4 to the consolidated financial statements, the Company changed its method of depreciation for certain of its property, plant and equipment assets in 2009.

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 9, 2012

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS
For the Years Ended December 31, 2011, 2010 and 2009
(in millions, except share and per share amounts)

	2011	2010	2009
Operating revenues	$ 6,800	$ 6,545	$ 6,463
Operating expenses:			
Fuel and purchased energy expense	4,349	3,974	3,897
Plant operating expense	904	868	868
Depreciation and amortization expense	550	570	456
Sales, general and other administrative expense	131	151	174
Other operating expenses	87	100	101
Total operating expenses	6,021	5,663	5,496
Impairment losses	—	116	4
(Gain) on sale of assets, net	—	(119)	—
(Income) from unconsolidated investments in power plants	(21)	(16)	(50)
Income from operations	800	901	1,013
Interest expense	760	813	815
Loss on interest rate derivatives	145	223	—
Interest (income)	(9)	(11)	(16)
Debt extinguishment costs	94	91	76
Other (income) expense, net	21	15	13
Income (loss) before income taxes and discontinued operations	(211)	(230)	125
Income tax expense (benefit)	(22)	(68)	15
Income (loss) before discontinued operations	(189)	(162)	110
Discontinued operations, net of tax expense	—	193	35
Net income (loss)	(189)	31	145
Net (income) loss attributable to the noncontrolling interest	(1)	—	4
Net income (loss) attributable to Calpine	$ (190)	$ 31	$ 149
Basic earnings (loss) per common share attributable to Calpine:			
Weighted average shares of common stock outstanding (in thousands)	485,381	486,044	485,659
Income (loss) before discontinued operations attributable to Calpine	$ (0.39)	$ (0.33)	$ 0.24
Discontinued operations, net of tax expense attributable to Calpine	—	0.39	0.07
Net income (loss) per common share attributable to Calpine — basic	$ (0.39)	$ 0.06	$ 0.31
Diluted earnings (loss) per common share attributable to Calpine:			
Weighted average shares of common stock outstanding (in thousands)	485,381	487,294	486,319
Income (loss) before discontinued operations attributable to Calpine	$ (0.39)	$ (0.33)	$ 0.24
Discontinued operations, net of tax expense attributable to Calpine	—	0.39	0.07
Net income (loss) per common share attributable to Calpine — diluted	$ (0.39)	$ 0.06	$ 0.31

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

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)
For the Years Ended December 31, 2011, 2010 and 2009
(in millions)

	2011	2010	2009
Net income (loss)	$ (189)	$ 31	$ 145
Cash flow hedging activities:			
Gain (loss) on cash flow hedges before reclassification adjustment for cash flow hedges realized in net income (loss)	(69)	25	180
Reclassification adjustment for (gain) loss on cash flow hedges realized in net (income) loss	(25)	141	(335)
Unrealized actuarial losses arising during period	(3)	—	—
Foreign currency translation gain (loss)	(1)	2	4
Income tax (expense) benefit	45	(27)	43
Other comprehensive income (loss)	(53)	141	(108)
Comprehensive income (loss)	(242)	172	37
Comprehensive (income) loss attributable to the noncontrolling interest	(1)	—	4
Comprehensive income (loss) attributable to Calpine	$ (243)	$ 172	$ 41

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

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
December 31, 2011 and 2010
(in millions, except share and per share amounts)

	2011	2010
ASSETS		
Current assets:		
Cash and cash equivalents ($285 and $345 attributable to VIEs)	$ 1,252	$ 1,327
Accounts receivable, net of allowance of $13 and $2	598	669
Margin deposits and other prepaid expense	193	221
Restricted cash, current ($57 and $177 attributable to VIEs)	139	195
Derivative assets, current	1,051	725
Inventory and other current assets	329	292
Total current assets	3,562	3,429
Property, plant and equipment, net ($4,313 and $6,602 attributable to VIEs)	13,019	12,978
Restricted cash, net of current portion ($53 and $52 attributable to VIEs)	55	53
Investments	80	80
Long-term derivative assets	113	170
Other assets	542	546
Total assets	$ 17,371	$ 17,256
LIABILITIES & STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 435	$ 514
Accrued interest payable	200	132
Debt, current portion ($41 and $132 attributable to VIEs)	104	152
Derivative liabilities, current	1,144	718
Income taxes payable	3	5
Other current liabilities	276	268
Total current liabilities	2,162	1,789
Debt, net of current portion ($2,522 and $4,069 attributable to VIEs)	10,321	10,104
Deferred income tax liability, non-current	—	77
Long-term derivative liabilities	279	370
Other long-term liabilities	245	247
Total liabilities	13,007	12,587
Commitments and contingencies (see Note 15)		
Stockholders' equity:		
Preferred stock, $0.001 par value per share; authorized 100,000,000 shares, none issued and outstanding at December 31, 2011 and 2010	—	—
Common stock, $0.001 par value per share; authorized 1,400,000,000 shares, 490,468,815 shares issued and 481,743,738 shares outstanding at December 31, 2011, and 444,883,356 shares issued and 444,435,198 shares outstanding at December 31, 2010	1	1
Treasury stock, at cost, 8,725,077 and 448,158 shares, respectively	(125)	(5)
Additional paid-in capital	12,305	12,281
Accumulated deficit	(7,699)	(7,509)
Accumulated other comprehensive loss	(178)	(125)
Total Calpine stockholders' equity	4,304	4,643
Noncontrolling interest	60	26
Total stockholders' equity	4,364	4,669
Total liabilities and stockholders' equity	$ 17,371	$ 17,256

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

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY
For the Years Ended December 31, 2011, 2010 and 2009
(in millions)

	Common Stock	Treasury Stock	Additional Paid-In Capital	Retained Earnings (Accumulated Deficit)	Accumulated Other Comprehensive Income (Loss)	Noncontrolling Interest	Total Stockholders' Equity
Balance, December 31, 2008	$ 1	$ (1)	$ 12,217	$ (7,689)	$ (158)	$ 2	$ 4,372
Treasury stock transactions	—	(2)	—	—	—	—	(2)
Stock-based compensation expense	—	—	38	—	—	—	38
Other	—	—	1	—	—	—	1
Net income (loss)	—	—	—	149	—	(4)	145
Other comprehensive loss	—	—	—	—	(108)	—	(108)
Balance, December 31, 2009	$ 1	$ (3)	$ 12,256	$ (7,540)	$ (266)	$ (2)	$ 4,446
Treasury stock transactions	—	(2)	—	—	—	—	(2)
Stock-based compensation expense	—	—	24	—	—	—	24
Other	—	—	1	—	—	28	29
Net income	—	—	—	31	—	—	31
Other comprehensive income	—	—	—	—	141	—	141
Balance, December 31, 2010	$ 1	$ (5)	$ 12,281	$ (7,509)	$ (125)	$ 26	$ 4,669
Treasury stock transactions	—	(120)	—	—	—	—	(120)
Stock-based compensation expense	—	—	24	—	—	—	24
Other	—	—	—	—	—	33	33
Net income (loss)	—	—	—	(190)	—	1	(189)
Other comprehensive loss	—	—	—	—	(53)	—	(53)
Balance, December 31, 2011	$ 1	$ (125)	$ 12,305	$ (7,699)	$ (178)	$ 60	$ 4,364

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, 2011, 2010 and 2009
(in millions)

	2011	2010	2009
Cash flows from operating activities:			
Net income (loss)	$ (189)	$ 31	$ 145
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation and amortization expense[(1)]	587	615	556
Debt extinguishment costs	82	91	37
Deferred income taxes	(21)	(26)	16
Impairment losses	—	116	4
(Gain) loss on sale of power plants and other, net	13	(314)	37
Unrealized mark-to-market activities, net	(30)	56	(87)
(Income) from unconsolidated investments in power plants	(21)	(16)	(50)
Return on unconsolidated investments in power plants	6	11	11
Stock-based compensation expense	24	24	38
Other	6	1	(2)
Change in operating assets and liabilities, net of effects of acquisitions:			
Accounts receivable	74	91	108
Derivative instruments, net	15	(52)	(118)
Other assets	1	277	235
Accounts payable and accrued expenses	28	(43)	(19)
Settlement of non-hedging interest rate swaps	189	69	—
Other liabilities	11	(2)	(150)
Net cash provided by operating activities	775	929	761
Cash flows from investing activities:			
Purchases of property, plant and equipment	(683)	(369)	(179)
Proceeds from sale of power plants, interests and other	13	954	—
Purchase of Conectiv assets and BRSP, net of cash acquired	—	(1,680)	—
Cash acquired due to consolidation of OMEC	—	8	—
Capital contributions to unconsolidated investments	—	—	(19)
Return of investment from unconsolidated investments	—	—	9
Settlement of non-hedging interest rate swaps	(189)	(69)	—
(Increase) decrease in restricted cash	54	322	(59)
Purchases of deferred transmission credits	(31)	—	—
Other	—	3	(2)
Net cash used in investing activities	(836)	(831)	(250)
Cash flows from financing activities:			
Borrowings under Term Loan and New Term Loan	1,657	—	—
Repayments on NDH Project Debt	(1,283)	—	—
Issuance of First Lien Notes	1,200	3,491	—
Repayments on First Lien Credit Facility	(1,195)	(3,477)	(785)
Borrowings from project financing, notes payable and other	327	1,272	1,034
Repayments of project financing, notes payable and other	(550)	(937)	(1,361)
Capital contributions from noncontrolling interest holder	33	17	—
Financing costs	(81)	(136)	(65)
Stock repurchases	(119)	—	—
Refund of financing costs	—	10	—
Other	(3)	—	(2)
Net cash provided by (used in) financing activities	(14)	240	(1,179)
Net increase (decrease) in cash and cash equivalents	(75)	338	(668)
Cash and cash equivalents, beginning of period	1,327	989	1,657
Cash and cash equivalents, end of period	$ 1,252	$ 1,327	$ 989

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

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS — (Continued)

(in millions)

	2011	2010	2009
Cash paid during the period for:			
Interest, net of amounts capitalized	$ 656	$ 635	$ 761
Income taxes	$ 18	$ 21	$ 7
Supplemental disclosure of non-cash investing and financing activities:			
Change in capital expenditures included in accounts payable	$ (24)	$ 1	$ 6
Settlement of commodity contract with project financing	$ —	$ —	$ 79
Liabilities assumed in BRSP acquisition	$ —	$ 85	$ —
Conversion of project debt to noncontrolling interest	$ —	$ 11	$ —
Issuance of First Lien Notes in exchange for First Lien Credit Facility term loans	$ —	$ —	$ 1,200
Amended Steamboat project debt	$ —	$ —	$ 448

(1) Includes depreciation and amortization included in fuel and purchased energy expense, interest expense and discontinued operations 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 primarily natural gas-fired and geothermal power plants in North America. We have a significant presence in major competitive wholesale power markets in California, Texas and the Mid-Atlantic region of the U.S. 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 and fuel oil as fuel for our power plants and in related natural gas transportation and storage transactions, and in the purchase of electric transmission rights to deliver power to our customers. We also enter into natural gas and power physical and financial contracts to economically 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 U.S. GAAP and include the accounts of all majority-owned subsidiaries that are not VIEs and all VIEs where we have determined we are the primary beneficiary. Intercompany transactions have been eliminated in consolidation.

Consolidation of OMEC — We were required by U.S. GAAP to adopt new accounting standards for VIEs which became effective January 1, 2010 that required us to perform an analysis to determine whether we should consolidate any of our previously unconsolidated VIEs or deconsolidate any of our previously consolidated VIEs. We completed our required analysis and determined that we are the primary beneficiary of OMEC. Accordingly, as required by U.S. GAAP, we consolidated OMEC effective January 1, 2010. Our Consolidated Financial Statements for the year ended December 31, 2009 present our investment in OMEC's revenues and expenses under the equity method of accounting. We made no other changes to our group of subsidiaries that we consolidate as a result of the adoption of these new standards. See Note 5 for further discussion of accounting for our VIEs.

Equity Method Investments — We use the equity method of accounting to record our net interests in VIEs where we have determined that we are not the primary beneficiary, which include Greenfield LP, a 50% partnership interest, and Whitby, a 50% equity interest. Our share of net income (loss) is calculated according to our equity ownership percentage or according to the terms of the applicable partnership agreement. See Note 5 for further discussion of our VIEs and unconsolidated investments.

Revision — We have revised the amount reported on our Consolidated Statement of Operations as loss on interest rate derivatives by approximately $24 million for the year ended December 31, 2010. The offsetting reduction was to the amount reported as interest expense. This revision had no impact on our financial condition, results of operations or cash flows. See Note 8 for further information about our interest rate swaps formerly hedging our First Lien Credit Facility.

Use of Estimates in Preparation of Financial Statements

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

Fair Value of Financial Instruments and Derivatives

The carrying values of accounts receivable, accounts payable and other receivables and payables approximate their respective fair values due to their short-term maturities. See Note 6 for disclosures regarding the fair value of our debt instruments and Notes 7 and 8 for disclosures regarding the fair values of our derivative instruments.

Concentrations of Credit Risk

Financial instruments that potentially subject us to credit risk consist of cash and cash equivalents, restricted cash, accounts and notes receivable and derivative assets. Certain of our cash and cash equivalents, as well as our restricted cash balances, are invested in money market accounts with investment banks that are not FDIC insured. We place our cash and cash equivalents and restricted cash in what we believe to be creditworthy 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.

Additionally, we actively monitor the credit risk of our counterparties, including our receivable, commodity and derivative transactions. Our accounts and notes receivable are concentrated within entities engaged in the energy industry, mainly within the U.S. We generally have not collected collateral for accounts receivable from utilities and end-user customers; however, we may require collateral in the future. For financial and commodity derivative counterparties, we evaluate the net accounts receivable, accounts payable and fair value of commodity contracts and may require security deposits, cash margin or letters of credit to be posted if our exposure reaches a certain level or their credit rating declines.

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, ISOs and other retail power suppliers; and
- oil, natural gas, chemical and other energy-related industrial companies.

We have concentrations of credit risk with a few of our commercial customers relating to our sales of power, steam and hedging and optimization activities. We have exposure to trends within the energy industry, including declines in the creditworthiness of our counterparties for our commodity and derivative transactions. 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 believe that our credit policies and portfolio of transactions adequately monitor and diversify our credit risk, and currently our counterparties are performing and financially settling timely according to their respective agreements.

We also have unfunded credit exposure to several European financial institutions related to our Russell City Project Debt and Los Esteros Project Debt. These financial institutions continue to provide construction funding in accordance with the terms of the debt agreements. Should one or all of these financial institutions be unable to perform under their obligations, it would not have a material adverse effect on our financial position or results of operations. See Note 6 for a further discussion of our Russell City Project Debt and Los Esteros Project Debt.

Cash and Cash Equivalents

We consider all highly liquid investments with an original maturity of three months or less to be cash equivalents. We have certain project finance facilities and lease agreements that require us to establish and maintain segregated cash accounts, which have been pledged as security in favor of the lenders under such project finance facilities, and the use of certain cash balances on deposit in such accounts is limited, at least temporarily, to the operations of the respective projects. At December 31, 2011 and 2010, we had cash and cash equivalents of $306 million and $269 million, respectively, that were subject to such project finance facilities and lease agreements.

Restricted Cash

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

The table below represents the components of our restricted cash as of December 31, 2011 and 2010 (in millions):

	2011			2010		
	Current	Non-Current	Total	Current	Non-Current	Total
Debt service[1]	$ 11	$ 42	$ 53	$ 44	$ 25	$ 69
Rent reserve	—	—	—	22	5	27
Construction/major maintenance	33	10	43	35	14	49
Security/project/insurance	79	—	79	75	7	82
Other	16	3	19	19	2	21
Total	$ 139	$ 55	$ 194	$ 195	$ 53	$ 248

(1) At both December 31, 2011 and 2010, debt service included approximately $25 million of repurchase agreements with a financial institution containing maturity dates greater than one year.

Accounts Receivable and Payable

Accounts receivable and payable represent amounts due from customers and owed to vendors, respectively. 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 collectability, 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 our marketing, hedging and optimization activities. Some of these receivables and payables with individual counterparties are subject to master netting arrangements whereby we legally have a right of offset and 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.

Inventory

At December 31, 2011 and 2010, we had inventory of $294 million and $262 million, respectively. Inventory primarily consists of spare parts, stored natural gas and fuel oil, emission reduction credits 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 are expensed to plant operating expense 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 first priority liens on the assets previously subject to first priority liens under our First Lien Notes, Corporate Revolving Facility, Term Loan and New Term Loan as collateral under certain of our power and natural gas agreements. These agreements qualify as "eligible commodity hedge agreements" under our First Lien Notes, Corporate Revolving Facility, Term Loan and New Term Loan and certain of our interest rate swap agreements. The first priority liens have been granted in order to reduce the cash collateral and letters of credit that we would otherwise be required to provide to our counterparties under such agreements. The counterparties under such agreements would share the benefits of the collateral subject to such first priority liens ratably with the lenders under our First Lien Notes, Corporate Revolving Facility, Term Loan and New Term Loan. See Note 9 for a further discussion on our amounts and use of collateral.

Deferred Financing Costs

Costs incurred related to the issuance of debt instruments are deferred and amortized over the term of the related debt using a method that approximates the effective interest rate method. However, when the timing of debt transactions involve contemporaneous exchanges of cash between us and the same creditor(s) in connection with the issuance of a new debt obligation

and satisfaction of an existing debt obligation, deferred financing costs are accounted for depending on whether the transaction qualifies as an extinguishment or modification, which requires us to either write off the original deferred financing costs and capitalize the new issuance costs, or continue to amortize the original deferred financing costs and immediately expense the new issuance costs.

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. When capital improvements to leased power plants meet our capitalization criteria they are capitalized as leasehold improvements and amortized over the shorter of the term of the lease or the economic life of the capital improvement. We expense maintenance when the service is performed for work that does not meet our capitalization criteria. Our current capital expenditures at our 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 our Geysers Assets as a proven steam reservoir and accounted for the assets under purchase accounting. All well costs, except well workovers, have been capitalized since our purchase date.

We depreciate our assets under the straight line method over the shorter of their estimated useful life or lease term using an estimated salvage value which approximates 10% of the depreciable cost basis for our power plant assets where we own the land or have a favorable option to purchase the land at conclusion of the lease term and approximately 0.15% of the depreciable costs basis for our rotable equipment. During 2009, we reviewed our accounting policies related to depreciation including our estimates of useful lives. We determined changing from composite depreciation to component depreciation for our rotable natural gas-fired power plant assets, and changing our Geysers Assets depreciation from the units of production method to the straight line method was preferable under U.S. GAAP. We also revised our estimates of useful lives. See Note 4 for further discussion regarding our changes in depreciation, changes in useful lives and the effective date of our changes.

Generally, upon normal retirement of assets under the composite depreciation method, the costs of such assets are retired against accumulated depreciation and no gain or loss is recorded. For the retirement of assets under the component depreciation method, generally, the costs and related accumulated depreciation of such assets are removed from our Consolidated Balance Sheets and a gain or loss is recorded as plant operating expense.

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 and definite-lived intangible assets for impairment, when events or changes in circumstances indicate that the carrying value of such assets may not be recoverable. 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. 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 loss. Equipment assigned to each power plant is not evaluated for impairment separately; instead, we evaluate our operating power plants and related equipment as a whole unit. 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 a construction or development project is no longer probable of completion and the capitalized costs will not be recovered through future operations, the carrying value of the project will be written down to its fair value.

In order to estimate future cash flows, we consider historical cash flows, existing and future contracts and PPAs 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 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 power and fuel costs and forecasted 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 their 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.

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 including contract terms, tenor and credit risk of counterparties. 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 power and fuel costs and forecasted 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.

During 2011, we did not record any impairment losses. During 2010, we impaired approximately $95 million related to South Point (see Note 3 for further information related to our acquisition of the South Point lease and subsequent impairment of our South Point assets) and development costs of approximately $21 million associated with two development projects that originated prior to our Chapter 11 bankruptcy proceedings. We continued to market these projects after our Effective Date, but during 2010 we determined that their continued development was unlikely. During 2009, we had miscellaneous impairments of approximately $4 million.

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, 2011 and 2010, our asset retirement obligation liabilities were $27 million and $51 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. Our asset retirement obligation liabilities for the year ended December 31, 2011 decreased by $24 million primarily related to a revision in the expected settlement dates of the asset retirement obligations on several of our power plants.

Revenue Recognition

Our operating revenues are composed of the following:

- power and steam revenue consisting of fixed and variable capacity payments, which are not related to generation including capacity payments received from PJM capacity auctions, variable payments for power and steam, which are related to generation, host steam and RECs from our Geysers Assets, and other revenues such as RMR Contracts, resource adequacy and certain ancillary service revenues;
- realized and unrealized revenues from derivative instruments as a result of our marketing, hedging and optimization activities; and
- other service revenues.

Power and Steam

Physical Commodity Contracts — We recognize revenue primarily from the sale of power and steam thermal energy for sale to our customers for use in industrial or other heating operations upon transmission and delivery to the customer.

We 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 and designated under the normal purchase normal sale exemption. We apply lease accounting to contracts that meet the definition of a lease and accrual accounting treatment to those contracts that are either 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. Where we do not take title of the commodities but receive a net variable payment to convert natural gas into power and steam in a tolling operation, we record the variable payment as revenue but do not record any fuel and purchased energy expense.

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

Leases — Contracts accounted for as operating leases, such as certain tolling agreements, 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):

2012	$	300
2013		287
2014		286
2015		288
2016		291
Thereafter		1,210
Total	$	2,662

Accounting for Derivative Instruments

We enter into a variety of derivative instruments including 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. We recognize all derivative instruments that qualify for derivative accounting treatment as either assets or liabilities and measure those instruments at fair value unless they qualify for and are designated under the normal purchase normal sale exemption. 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. See Note 8 for a further discussion on our accounting for derivatives.

Fuel and Purchased Energy Expense

Fuel and purchased energy expense is composed of the cost of natural gas and fuel oil purchased from third parties for the purposes of consumption in our power plants as fuel, and the cost of power and natural gas purchased from third parties for marketing, hedging and optimization activities as well as realized and unrealized mark-to-market gains and losses resulting from general market price movements against certain derivative natural gas contracts including financial gas transactions economically hedging anticipated future power sales that do not qualify for hedge accounting treatment.

Plant Operating Expense

Plant operating expense primarily includes employee expenses, utilities, chemicals, repairs and maintenance, insurance and property taxes. We recognize these expenses when the service is performed or in the period in which the expense relates.

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 basis 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 due to 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. See Note 10 for a further discussion on our income taxes.

Earnings (Loss) per Share

Basic earnings (loss) per share is calculated using the weighted average shares outstanding during the period and includes restricted stock units for which no future service is required as a condition to the delivery of the underlying common stock. Diluted earnings (loss) per share is calculated by adjusting the weighted average shares outstanding by the dilutive effect of share-based awards using the treasury stock method. See Note 11 for a further discussion of our earnings (loss) per share.

Stock-Based Compensation

We use the Black-Scholes option-pricing model or the Monte Carlo simulation model to estimate the fair value of our employee stock options on the grant date. The Black-Scholes option-pricing model and the Monte Carlo simulation model take into account certain variables, which are further explained in Note 12.

New Accounting Standards and Disclosure Requirements

Fair Value Measurement — In May 2011, FASB issued Accounting Standards Update 2011-04, "Fair Value Measurement" to clarify and amend the application or requirements relating to fair value measurements and disclosures relating to fair value measurements. The update stems from the FASB and the International Accounting Standards Board project to develop common requirements for measuring fair value and for disclosing information about fair value measurements. The update is not expected to impact any of our fair value measurements but will require disclosure of the following:

- quantitative information about the unobservable inputs used in a fair value measurement that is categorized within level 3 of the fair value hierarchy;
- for those fair value measurements categorized within level 3 of the fair value hierarchy, both the valuation processes used and the sensitivity of the fair value measurement to changes in unobservable inputs and the interrelationships between those unobservable inputs, if any; and
- the categorization by level of the fair value hierarchy for items that are not measured at fair value in the statement of financial position but for which the fair value is required to be disclosed.

The new requirements relating to fair value measurements are prospective and effective for interim and annual periods beginning after December 15, 2011, with early adoption prohibited. We do not expect that the adoption of this standard will have a material impact on our results of operations, cash flows or financial condition.

Comprehensive Income — In June 2011, FASB issued Accounting Standards Update 2011-05, "Comprehensive Income" to amend requirements relating to the presentation of comprehensive income. The update eliminates the option to present components of other comprehensive income as part of the statement of changes in stockholders' equity and provides an entity with the option to present comprehensive income in a single continuous financial statement or in two separate but consecutive statements. The new requirements relating to the presentation of comprehensive income are retrospective and effective for interim and annual periods beginning after December 15, 2011, with early adoption permitted. Also, in December 2011, FASB issued Accounting Standards Update 2011-12, "Comprehensive Income" to abrogate the requirement for presentation in the income statement of the effect on net income of reclassification adjustments out of AOCI as required in Accounting Standards Update 2011-05. We adopted all of the presentation requirements related to these updates for the year ended December 31, 2011.

Disclosures about Offsetting Assets and Liabilities — In December 2011, FASB issued Accounting Standards Update 2011-11, "Balance Sheet - Disclosures about Offsetting Assets and Liabilities" to enhance disclosure requirements relating to the offsetting of assets and liabilities on an entity's balance sheet. The update requires enhanced disclosures regarding assets and liabilities that are presented net or gross in the statement of financial position when the right of offset exists, or that are subject to an enforceable master netting arrangement. The new disclosure requirements relating to this update are retrospective and effective for annual and interim periods beginning on or after January 1, 2013. The update only requires additional disclosures, as such, we do not expect that the adoption of this standard will have a material impact on our results of operations, cash flows or financial condition.

3. Acquisitions, Divestitures and Discontinued Operations

Conectiv Acquisition

On July 1, 2010, we, through our indirect, wholly owned subsidiary NDH, completed the Conectiv Acquisition. The assets acquired include 18 operating power plants and the York Energy Center that was under construction and achieved COD on March 2, 2011, totaling 4,491 MW of capacity. We did not acquire Conectiv's trading book, load serving auction obligations or collateral requirements. Additionally, we did not assume any of Conectiv's off-site environmental liabilities, environmental remediation liabilities in excess of $10 million related to assets located in New Jersey that are subject to ISRA, or pre-close accumulated pension and retirement welfare liabilities; however, we did assume pension liabilities on future services and compensation increases for past services for approximately 130 grandfathered union employees who joined Calpine as a result of the Conectiv Acquisition. During the second half of 2010, we initiated a voluntary retirement incentive program which reduced the number of employees covered by our pension obligation by 31 employees. The net proceeds of $1.3 billion received from the NDH Project Debt were used, together with available operating cash, to pay the Conectiv Acquisition purchase price of

approximately $1.64 billion and also fund a cash contribution from Calpine Corporation to NDH of $110 million to fund completion of the York Energy Center.

The Conectiv Acquisition provided us with a significant presence in the Mid-Atlantic market, one of the most robust competitive power markets in the U.S., and positioned us with three scale markets instead of two (California and Texas) giving us greater geographic diversity. We accounted for the Conectiv Acquisition under the acquisition method of accounting in accordance with U.S. GAAP.

During the second quarter of 2011, we finalized the valuations of the net assets acquired in the Conectiv Acquisition which is summarized in the following table (in millions). We did not record any material valuation adjustments during the first half of 2011, and we did not recognize any goodwill as a result of this acquisition.

Consideration	$	1,640
Final values of identifiable assets acquired and liabilities assumed:		
Assets:		
Current assets	$	78
Property, plant and equipment, net		1,574
Other long-term assets		85
Total assets acquired		1,737
Liabilities:		
Current liabilities		46
Long-term liabilities		51
Total liabilities assumed		97
Net assets acquired	$	1,640

Acquisition of Broad River and South Point Leases

On December 8, 2010, we, through our wholly owned, indirect subsidiary, Calpine BRSP, purchased entities from CIT Capital USA Inc. that held the leases for our Broad River and South Point power plants by assuming debt with a fair value of approximately $297 million and a cash payment of approximately $40 million. Prior to this purchase, our Broad River power plant was operated under a sale-leaseback transaction that was accounted for as a failed sale-leaseback financing transaction and our South Point power plant was accounted for as an operating lease. The purchase of the entities holding the power plant leases only added an incremental $85 million in consolidated debt, as the transaction eliminated approximately $212 million recorded as debt and accrued interest owed to CIT Capital USA Inc. under our Broad River power plant lease.

We recorded a total pre-tax loss of approximately $125 million on our Consolidated Statement of Operations for the year ended December 31, 2010 for this transaction, which was recorded as shown below (in millions):

Broad River: debt extinguishment costs	$	30
South Point: impairment loss		95
Total loss recorded for this transaction	$	125

Broad River — Prior to the purchase, we operated the Broad River power plant under a lease that was accounted for as a failed sale-leaseback financing transaction under U.S. GAAP. The lease liability was included in project financing, notes payable and other debt balance and the power plant assets were included in our property plant and equipment. As a result of the purchase, we did not adjust the historical value of the assets. We allocated the value of the consideration paid in the transaction based upon the fair value of both plants, and the result was an allocation of assumed debt that was greater than the prior debt obligation resulting in a pre-tax loss of approximately $30 million. Because we primarily exchanged future lease obligations for a debt obligation, the resulting loss is recorded as debt extinguishment costs for accounting purposes.

South Point — Prior to the purchase, we accounted for the South Point lease as an operating lease. We allocated the consideration paid in the transaction based upon the fair value of both plants. The result was an allocation of consideration paid for South Point that was in excess of the fair value of assets acquired by approximately $95 million, which was primarily due to the elimination of a lease levelization asset associated with the prior lease, which was no longer proper on a consolidated basis. The resulting loss has been reported as an impairment loss for accounting purposes.

While the transaction resulted in a one-time, pre-tax loss, in the longer-term, the acquisition of these entities grants us greater flexibility and more control of the future operation of both plants and simplified a previously complex leasing arrangement.

Sale of Blue Spruce and Rocky Mountain

On December 6, 2010, we, through our indirect, wholly owned subsidiaries Riverside Energy Center, LLC and CDHI, completed the sale of 100% of our ownership interests in Blue Spruce and Rocky Mountain for approximately $739 million, and we recorded a pre-tax gain of approximately $209 million during the fourth quarter of 2010. The results of operations for Blue Spruce and Rocky Mountain are reported as discontinued operations on our Consolidated Statement of Operations for years ended December 31, 2010 and 2009.

Discontinued Operations

The table below presents the components of our discontinued operations for the periods presented (in millions):

	2010	2009
Operating revenues	$ 92	$ 101
Gain on disposal of discontinued operations	209	—
Income from discontinued operations before taxes	43	35
Less: Income tax expense	59	—
Discontinued operations, net of tax	$ 193	$ 35

Other Asset Sales

On December 8, 2010, we sold a 25% undivided interest in the assets of our Freestone power plant for approximately $215 million in cash. We recorded a pre-tax gain of approximately $119 million in December 2010, which is included in (gain) on sale of assets, net on our Consolidated Statement of Operations. We continue to operate Freestone after the sale.

4. Property, Plant and Equipment, Net

As of December 31, 2011 and 2010, the components of property, plant and equipment, are stated at cost less accumulated depreciation as follows (in millions):

	2011	2010
Buildings, machinery and equipment	$ 15,074	$ 14,669
Geothermal properties	1,163	1,102
Other	156	182
	16,393	15,953
Less: Accumulated depreciation	4,158	3,690
	12,235	12,263
Land	91	93
Construction in progress	693	622
Property, plant and equipment, net	$ 13,019	$ 12,978

Total depreciation expense, including amortization of leased assets, recorded in income from operations and discontinued operations for the years ended December 31, 2011, 2010 and 2009, was $560 million, $568 million and $469 million, respectively.

We have various debt instruments that are collateralized by certain of our property, plant and equipment. See Note 6 for a detailed discussion of such instruments.

Change in Depreciation Methods, Useful Lives and Salvage Values

During 2009, we reviewed our accounting policies related to depreciation including our estimates of useful lives and salvage values. As further described below, effective October 1, 2009, we made two changes to our methods of depreciation including (i) changing from composite depreciation to component depreciation for our rotable parts utilized in our natural gas-fired power plants and (ii) changing from the units of production method to the straight line method for our Geysers Assets. In addition, we completed a life study for each of our natural gas-fired power plants and our Geysers Assets, and changed our estimate of their remaining useful lives.

Component Depreciation for Rotable Parts at our Natural Gas-Fired Power Plants — Effective October 1, 2009, we componentized our rotable parts for our natural gas-fired power plant assets for purposes of calculating depreciation. Prior to October 1, 2009, we used the composite depreciation method for all of our natural gas-fired power plant assets. Under this method, all assets comprising each power plant were combined into one group and depreciated under a composite depreciation rate. The change in the method of depreciation for rotable parts was considered a change in accounting estimate inseparable from a change in accounting principle, and resulted in changes to our depreciation expense prospectively. The change to component depreciation for our rotable parts utilized in our natural gas-fired power plants also resulted in changes to the useful lives of our rotable parts which are now generally estimated to range from 3 to 18 years. Furthermore, we reduced our estimate of salvage value for our rotable parts to 0.15% of original cost to reflect our expectation with these separable parts. Prior to this change, our composite useful lives for our natural gas-fired power plant assets, including our rotable parts, were 35 years and 40 years for our combined-cycle and our simple-cycle power plant assets, respectively. We also revised the estimated useful lives of our remaining composite pools to 37 years and 47 years for our combined-cycle and simple-cycle power plant assets, respectively, based in part on the results of our separate useful life study. Our change in useful lives is considered a change in accounting estimate and resulted in changes to our depreciation expense prospectively.

Straight Line Method for our Geysers Assets — Effective October 1, 2009, we began calculating our depreciation for our Geysers Assets under the straight line method. Prior to October 1, 2009, our Geysers Assets used the units of production method for depreciation. Our units of production depreciation rate was 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 was determined by dividing the depreciable base by total expected future generation. The change in depreciation methods was made because steam flow decline rates have become very small over the past several years as a result of our water injection program where, on average, we reinject approximately 18 million gallons of reclaimed wastewater a day back into the reservoir to replenish natural steam withdrawn for the production of power. The expectation is that the steam reservoir at our Geysers Assets will be able to supply economic quantities of steam for the foreseeable future and expected future generation is now only limited by the physical useful life of the Geysers Assets. As a result of our change from the units of production method to the straight line method for our Geysers Assets, and based in part on the results of our separate useful life study, we revised our estimates of the remaining composite useful lives of our Geysers Assets effective October 1, 2009 to 59 years and 13 years for our Geysers steam extraction and gathering assets and our Geysers power plant assets, respectively. Our change in the method of depreciation for our Geysers Assets is considered a change in accounting estimate inseparable from a change in accounting principle, and resulted in changes to depreciation expense prospectively.

The changes described above resulted in an increase in our historical depreciation expense of approximately $28 million related to our natural gas-fired power plants and a decrease in historical depreciation expense of approximately $3 million for our Geysers Assets for a net decrease to our net income attributable to Calpine of approximately $25 million or approximately $(0.05) to our basic and diluted earnings per share for the year ended December 31, 2009.

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 6 for further information regarding these assets under capital leases.

Other

This component primarily includes software and emission reduction credits that are power plant specific and not available to be sold.

Capitalized Interest

The total amount of interest capitalized was $24 million, $15 million and $8 million for the years ended December 31, 2011, 2010 and 2009, respectively.

5. Variable Interest Entities and Unconsolidated Investments

We consolidate all of our VIEs where we have determined that we are the primary beneficiary. We have the following types of VIEs consolidated in our financial statements:

Subsidiaries with Project Debt — All of our subsidiaries with project debt not guaranteed by Calpine have PPAs that provide financial support and are thus considered VIEs. We retain ownership and absorb the full risk of loss and potential for reward once the project debt is paid in full. Actions by the lender to assume control of collateral can occur only under limited circumstances such as upon the occurrence of an event of default, which we have determined to be unlikely. See Note 6 for further information regarding our project debt and Note 2 for information regarding our restricted cash balances.

Subsidiaries with PPAs — Certain of our majority owned subsidiaries have PPAs that limit the risk and reward of our ownership and thus constitute a VIE.

VIEs with a Purchase Option — Riverside Energy Center and OMEC have agreements that provide third parties a fixed price option to purchase power plant assets exercisable in the years 2012 and 2019, respectively, with an aggregate capacity of 1,211 MW. These purchase options limit the risk and reward of our ownership and, thus, constitute a VIE.

Consolidation of VIEs

We consolidate our VIEs where we determine that we have both the power to direct the activities of a VIE that most significantly impact the VIE's economic performance and the obligation to absorb losses or receive benefits from the VIE. We have determined that we hold the obligation to absorb losses and receive benefits in all of our VIEs where we hold the majority equity interest. Therefore, our determination of whether to consolidate is based upon which variable interest holder has the power to direct the most significant activities of the VIE (the primary beneficiary). Our analysis includes consideration of the following primary activities which we believe to have a significant impact on a power plant's financial performance: operations and maintenance, plant dispatch, and fuel strategy as well as our ability to control or influence contracting and overall plant strategy. Our approach to determining which entity holds the powers and rights is based on powers held as of the balance sheet date. Contractual terms that may change the powers held in future periods, such as a purchase or sale option, are not considered in our analysis. Based on our analysis, we believe that we hold the power and rights to direct the most significant activities of all our majority owned VIEs.

Under our consolidation policy and under U.S. GAAP we also:

- perform an ongoing reassessment each reporting period of whether we are the primary beneficiary of our VIEs; and
- evaluate if an entity is a VIE and whether we are the primary beneficiary whenever any changes in facts and circumstances occur such that the holders of the equity investment at risk, as a group, lose the power from voting rights or similar rights of those investments to direct the activities of a VIE that most significantly impact the VIE's economic performance or when there are other changes in the powers held by individual variable interest holders.

On August 23, 2011, we closed on the $373 million Los Esteros Project Debt to fund the upgrade of our Los Esteros Critical Energy Facility from a 188 MW simple-cycle power plant to a 308 MW combined-cycle generation power plant. The addition of this project debt resulted in Los Esteros Critical Energy Facility, LLC meeting the definition of a VIE for which we have determinded we are the primary beneficiary. There were no other changes to our determination of whether we are the primary beneficiary of our VIEs for the year ended December 31, 2011.

Noncontrolling Interest — We own a 75% interest in Russell City Energy Company, LLC, one of our VIEs, which is also 25% owned by a third party. We fully consolidate this entity in our Consolidated Financial Statements and account for the third party ownership interest as a noncontrolling interest.

VIE Disclosures

U.S. GAAP requires separate disclosure on the face of our Consolidated Balance Sheets of the significant assets of a consolidated VIE that can only be used to settle obligations of the consolidated VIE and the significant liabilities of a consolidated VIE for which creditors (or beneficial interest holders) do not have recourse to the general credit of the primary beneficiary. In determining which assets of our VIEs met the separate disclosure criteria, we determined this separate disclosure requirement is met where Calpine Corporation is substantially limited or prohibited from access to assets (primarily cash and cash equivalents, restricted cash and property, plant and equipment), and where there are agreements that prohibit the debt holders of the VIE from

recourse to the general credit of Calpine Corporation or its other subsidiaries. In determining which liabilities of our VIEs met the separate disclosure criteria, we reviewed all of our VIEs and determined this separate disclosure requirement was met where our VIEs had project financing that prohibits the VIE from providing guarantees on the debt of others and where the amounts were material to our financial statements.

The VIEs meeting the above disclosure criteria are majority owned subsidiaries of Calpine Corporation and include natural gas-fired power plants with an aggregate capacity of approximately 11,391 MW, including 584 MW under construction, and 13,656 MW, including 1,029 MW under construction, at December 31, 2011 and 2010, respectively. For these VIEs, we may provide other operational and administrative support through various affiliate contractual arrangements among the VIEs, Calpine Corporation and its other wholly owned subsidiaries whereby we support the VIE through the reimbursement of costs and/or the purchase and sale of energy. Calpine Corporation provided support to these VIEs in the form of cash and other contributions other than amounts contractually required of $171 million for the year ended December 31, 2011. During the year ended December 31, 2010, Calpine Corporation provided $540 million to NDH, an indirect, wholly owned subsidiary, to fund the Conectiv Acquisition, including $110 million to complete the construction of the York Energy Center. Additionally, Calpine Corporation provided support to our other VIEs in the form of cash and other contributions other than amounts contractually required of $46 million during the year ended December 31, 2010.

Unconsolidated VIEs and Investments

We have a 50% partnership interest in Greenfield LP and in Whitby. Greenfield LP and Whitby are also VIEs; however, we do not have the power to direct the most significant activities of these entities and therefore do not consolidate them. We account for these entities under the equity method of accounting and include our net equity interest in investments on our Consolidated Balance Sheets. During 2009, we were not the primary beneficiary of OMEC based upon the accounting guidance in 2009, and did not consolidate OMEC. As required by U.S. GAAP, we consolidated OMEC effective January 1, 2010. At December 31, 2011 and 2010, our equity method investments included on our Consolidated Balance Sheets were comprised of the following (in millions):

	Ownership Interest as of December 31, 2011	2011	2010
Greenfield LP	50%	72	77
Whitby	50%	8	3
Total investments		$ 80	$ 80

Our risk of loss related to our unconsolidated VIEs is limited to our investment balance. Holders of the debt of our unconsolidated investments do not have recourse to Calpine Corporation and its other subsidiaries; therefore, the debt of our unconsolidated investments is not reflected on our Consolidated Balance Sheets. At December 31, 2011 and 2010, equity method investee debt was approximately $462 million and $494 million, respectively, and based on our pro rata share of each of the investments, our share of such debt would be approximately $231 million and $247 million at December 31, 2011 and 2010, respectively.

Our equity interest in the net income from OMEC for the year ended December 31, 2009, and both Greenfield LP and Whitby for the years ended December 31, 2011, 2010 and 2009 are recorded in (income) from unconsolidated investments in power plants. The following table sets forth details of our (income) from unconsolidated investments in power plants for the years indicated (in millions):

	(Income) from Unconsolidated Investments in Power Plants			Distributions		
	2011	2010	2009	2011	2010	2009
OMEC[1]	$ —	$ —	$ (32)	$ —	$ —	$ 9
Greenfield LP	(12)	(8)	(16)	2	6	9
Whitby	(9)	(8)	(2)	4	5	2
Total	$ (21)	$ (16)	$ (50)	$ 6	$ 11	$ 20

(1) OMEC was consolidated effective January 1, 2010. See Note 2.

Greenfield LP — Greenfield LP is a limited partnership between certain subsidiaries of ours and of Mitsui & Co., Ltd., which operates the Greenfield Energy Centre, a 1,038 MW natural gas-fired, combined-cycle power plant located in Ontario, Canada. We and Mitsui & Co., Ltd. each hold a 50% interest in Greenfield LP. Greenfield LP holds an 18-year term loan in the amount of CAD $648 million. Borrowings under the project finance facility bear interest at Canadian LIBOR plus 1.125% or Canadian prime rate plus 0.125%.

Whitby — Whitby is a limited partnership between certain subsidiaries of ours and Atlantic Packaging Ltd., which operates the Whitby facility, a 50 MW natural gas-fired, simple-cycle cogeneration power plant located in Ontario, Canada. We and Atlantic Packaging Ltd. each hold a 50% partnership interest in Whitby.

Inland Empire Energy Center Put and Call Options — We hold a call option to purchase the Inland Empire Energy Center (a 775 MW natural gas-fired power plant located in California which achieved COD on May 3, 2010) from GE that may be exercised between years 7 and 14 after the start of commercial operation. GE holds a put option whereby they can require us to purchase the power plant, if certain plant performance criteria are met during year 15 after the start of commercial operation. We determined that we were not the primary beneficiary of the Inland Empire power plant, and we do not consolidate it due to, but not limited to, the fact that GE directs the most significant activities of the power plant including operations and maintenance.

Significant Subsidiary — OMEC met the criteria of a significant unconsolidated subsidiary for the year ended December 31, 2009. OMEC was consolidated effective January 1, 2010. The condensed combined financial statements for our unconsolidated subsidiaries for the period in which OMEC was a significant unconsolidated subsidiary and was accounted for under the equity method of accounting is presented below (in millions):

Condensed Combined Statement of Operations
of Our Unconsolidated Subsidiaries
For the Year Ended December 31, 2009

	2009
Revenues	$ 256
Operating expenses	195
Income from operations	61
Interest (income) expense	2
Other (income) expense, net	5
Net income	$ 54

6. Debt

Our debt at December 31, 2011 and 2010, was as follows (in millions):

	2011	2010
First Lien Notes[1]	$ 5,892	$ 4,691
Project financing, notes payable and other[2][3]	1,691	1,922
Term Loan and New Term Loan[2][4]	1,646	—
CCFC Notes	972	965
Capital lease obligations	224	236
NDH Project Debt[4]	—	1,258
First Lien Credit Facility[1]	—	1,184
Total debt	10,425	10,256
Less: Current maturities	104	152
Debt, net of current portion	$ 10,321	$ 10,104

(1) On January 14, 2011, we repaid and terminated the First Lien Credit Facility with the issuance of the 2023 First Lien Notes as discussed below.

(2) On June 17, 2011, we repaid approximately $340 million of project debt with the proceeds received from $360 million in borrowings under the New Term Loan as further described below.

(3) On June 24, 2011, we closed on the approximately $845 million Russell City Project Debt to fund the construction of Russell City and on August 23, 2011, we closed on the $373 million Los Esteros Project Debt to fund the upgrade of our Los Esteros Critical Energy Facility, both further described below.

(4) On March 9, 2011, we borrowed $1.3 billion under the Term Loan and repaid and terminated the NDH Project Debt as discussed below.

Annual Debt Maturities

Contractual annual principal repayments or maturities of debt instruments as of December 31, 2011, are as follows (in millions):

2012	$ 104
2013	135
2014	392
2015	164
2016	1,177
Thereafter	8,496
Total debt	10,468
Less: Discount	43
Total	$ 10,425

Our First Lien Notes and Termination of the First Lien Credit Facility

Our First Lien Notes are summarized in the table below (in millions, except for interest rates):

	Outstanding at December 31,		Weighted Average Effective Interest Rates[1]	
	2011	2010	2011	2010
2017 First Lien Notes	$ 1,200	$ 1,200	7.5%	7.5%
2019 First Lien Notes	400	400	8.2	8.2
2020 First Lien Notes	1,092	1,091	8.1	8.1
2021 First Lien Notes	2,000	2,000	7.7	7.7
2023 First Lien Notes[2]	1,200	—	8.0	—
Total First Lien Notes	$ 5,892	$ 4,691		

(1) Our weighted average interest rate calculation includes the amortization of deferred financing costs and debt discount.

(2) On January 14, 2011, we issued $1.2 billion in aggregate principal amount of 7.875% senior secured notes due 2023 in a private placement. Interest on the 2023 First Lien Notes is payable semi-annually on January 15 and July 15 of each year, beginning on July 15, 2011. The 2023 First Lien Notes will mature on January 15, 2023.

Following our emergence from Chapter 11, our First Lien Credit Facility served as our primary debt facility. Beginning in late 2009, we began to repay or exchange our First Lien Credit Facility term loans through proceeds received from the issuances of the First Lien Notes, together with operating cash. On January 14, 2011, we repaid the remaining approximately $1.2 billion from the proceeds from the issuance of the 2023 First Lien Notes, together with operating cash, thereby terminating the First Lien Credit Facility in accordance with its terms.

Our First Lien Notes are secured equally and ratably with indebtedness incurred under our Corporate Revolving Facility, Term Loan and New Term Loan (described below), subject to certain exceptions and permitted liens, on substantially all of our and certain of the guarantors' existing and future assets. Additionally, our First Lien Notes rank equally in right of payment with all of our and the guarantors' other existing and future senior indebtedness, and will be effectively subordinated in right of payment to all existing and future liabilities of our subsidiaries that do not guarantee our First Lien Notes. Repayment of the NDH Project Debt also eliminated the restrictions against our NDH subsidiaries being guarantors to our First Lien Notes and Corporate Revolving Facility. On March 9, 2011, we executed assumption agreements to the amended and restated guarantee and collateral agreement, to add our NDH subsidiaries as guarantors to our Corporate Revolving Facility and Term Loan. On April 26, 2011, we executed supplemental indentures for the First Lien Notes to add the NDH subsidiaries as guarantors. On June 17, 2011, we executed assumption agreements to the amended and restated guarantee and collateral agreement, to add Deer Park Holdings, LLC, Metcalf Holdings, LLC, Deer Park Energy Center LLC and Metcalf Energy Center, LLC as guarantors of our Corporate Revolving Facility, Term Loan and New Term Loan. On July 22, 2011, we executed supplemental indentures for the First Lien Notes to add Deer Park Holdings, LLC, Metcalf Holdings, LLC, Deer Park Energy Center LLC and Metcalf Energy Center, LLC as guarantors.

Subject to certain qualifications and exceptions, our First Lien Notes will, among other things, limit our ability and the ability of the guarantors to:

- incur or guarantee additional first lien indebtedness;
- enter into certain types of commodity hedge agreements that can be secured by first lien collateral;
- enter into sale and leaseback transactions;
- create or incur liens; and
- consolidate, merge or transfer all or substantially all of our assets and the assets of our restricted subsidiaries on a combined basis.

In connection with the issuance of the 2023 First Lien Notes, we recorded approximately $22 million of deferred financing costs on our Consolidated Balance Sheet during 2011, and we recorded approximately $19 million in debt extinguishment costs during the year ended December 31, 2011, related to the repayment and termination of the First Lien Credit Facility.

The Term Loan and the New Term Loan and Repayment of the NDH Project Debt and Other Project Debt

On March 9, 2011, we entered into and borrowed $1.3 billion under the Term Loan. We used the net proceeds received, together with operating cash on hand to fully retire the approximately $1.3 billion NDH Project Debt in accordance with its repayment terms. The NDH Project Debt was originally established to partially fund the Conectiv Acquisition.

The Term Loan provides for a senior secured term loan facility in an aggregate principal amount of $1.3 billion and bears interest, at our option, at either (i) the base rate, equal to the higher of the Federal Funds effective rate plus 0.5% per annum or the Prime Rate (as such terms are defined in the Term Loan credit agreement), plus an applicable margin of 2.25%, or (ii) LIBOR plus 3.25% per annum subject to a LIBOR floor of 1.25%.

An aggregate amount equal to 0.25% of the aggregate principal amount of the Term Loan will be payable at the end of each quarter commencing on June 30, 2011, with the remaining balance payable on the maturity date (April 1, 2018). We may elect from time to time to convert all or a portion of the Term Loan from initial LIBOR rate loans to base rate loans or vice versa. In addition, we may at any time, and from time to time, prepay the Term Loan, in whole or in part, without premium or penalty, upon irrevocable notice to the administrative agent. We may also reprice the interest rate on the Term Loan, subject to approval from the Lenders and subject to a 1% premium if a repricing transaction occurs prior to the first anniversary of the closing date. We may elect to extend the maturity of any term loans under the Term Loan, in whole or in part subject to approval from those lenders holding such term loans. The Term Loan is subject to certain qualifications and exceptions, similar to our First Lien Notes.

If a change of control triggering event occurs, the Company shall notify the administrative agent in writing and shall make an offer to prepay the entire principal amount of the Term Loan outstanding within thirty (30) days after the date of such change of control triggering event.

In connection with the Term Loan, the Company and its subsidiaries (subject to certain exceptions) have made certain representations and warranties and are required to comply with various affirmative and negative covenants. The Term Loan is subject to customary events of default included in financing transactions, including, among others, failure to make payments when due, certain defaults under other material indebtedness, breach of certain covenants, breach of certain representations and warranties, involuntary or voluntary bankruptcy, and material judgments. If an event of default arises from certain events of bankruptcy or insolvency, all amounts outstanding under the Term Loan will become due and payable immediately without further action or notice. If other events of default arise (as defined in the Credit Agreement) and are continuing, the lenders holding more than 50% of the outstanding Term Loan amounts (as defined in the Credit Agreement) may declare all the Term Loan amounts outstanding to be due and payable immediately.

In connection with the Term Loan, we recorded deferred financing costs of approximately $14 million on our Consolidated Balance Sheet during 2011, and we recorded approximately $74 million in debt extinguishment costs during the year ended December 31, 2011, which includes approximately $36 million from the write-off of unamortized deferred financing costs, the write-off of approximately $25 million of debt discount and approximately $13 million in prepayment premiums related to the NDH Project Debt.

On June 17, 2011, we repaid approximately $340 million of project debt with the proceeds received from $360 million in borrowings under the New Term Loan. The New Term Loan carries substantially the same terms as the Term Loan and matures on April 1, 2018. The New Term Loan also contains very similar covenants, qualifications, exceptions and limitations as the Term Loan and First Lien Notes.

In connection with the New Term Loan, we recorded deferred financing costs of approximately $5 million on our Consolidated Balance Sheet during 2011, and we recorded approximately $5 million in debt extinguishment costs during the year ended December 31, 2011.

Project Financing, Notes Payable and Other

The components of our project financing, notes payable and other are (in millions, except for interest rates):

	Outstanding at December 31,		Weighted Average Effective Interest Rates[1]	
	2011	2010	2011	2010
Steamboat due 2017	$ 437	$ 445	6.6%	6.6%
OMEC due 2019	355	364	6.8	6.8
Russell City	244	—	4.1	—
Calpine BRSP due 2014	232	297	5.7	5.7
Pasadena[2]	185	208	8.8	8.6
Bethpage Energy Center 3, LLC due 2020-2025[3]	98	103	7.0	7.0
Los Esteros	83	—	3.8	—
Gilroy note payable due 2014	49	64	10.6	10.6
Metcalf[4]	—	251	—	6.9
Deer Park[4]	—	99	—	7.7
Gilroy Energy Center, LLC	—	38	—	7.3
Whitby Holdings[5]	—	26	—	9.1
GEC Holdings, LLC preferred interest	—	14	—	16.6
Other	8	13	—	—
Total	$ 1,691	$ 1,922		

(1) Our weighted average interest rate calculation includes the amortization of deferred financing costs and debt discount.

(2) Represents a sale-leaseback transaction that is accounted for as financing transaction under U.S. GAAP.

(3) Represents a weighted average of first and second lien loans for the weighted average effective interest rates.

(4) On June 17, 2011, we repaid Metcalf and Deer Park project debt with the proceeds received from $360 million in borrowings under the New Term Loan as further described above.

(5) The Whitby Holdings debt was purchased from a third party in 2011.

Our 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.

Russell City — On June 24, 2011, we, through our indirect, partially owned subsidiary Russell City Energy Company, LLC, closed on our approximately $845 million Russell City Project Debt to finance construction of Russell City, a 619 MW natural gas-fired, combined-cycle power plant under construction located in Hayward, California, which is comprised of a $700 million construction loan facility, an approximately $77 million project letter of credit facility and a $68 million debt service reserve letter of credit facility. The construction loan converts to a ten year term loan when commercial operations commence. Borrowings bear interest initially at LIBOR plus 2.25%. At December 31, 2011, approximately $244 million had been drawn under the construction loan and approximately $61 million of letters of credit were issued under the letter of credit facilities. Calpine's pro rata share would be 75% and the pro rata share related to the noncontrolling interest would be 25%.

In connection with the closing of the Russell City Project Debt, we recorded deferred financing costs of approximately $27 million on our Consolidated Balance Sheet during 2011.

Los Esteros — On August 23, 2011, we, through our indirect, wholly owned subsidiary Los Esteros Critical Energy Facility, LLC, closed on our $373 million Los Esteros Project Debt to finance the upgrade of our Los Esteros Critical Energy Facility from a 188 MW simple-cycle power plant to a 308 MW combined-cycle generation power plant. The upgrade will also increase the efficiency and environmental performance of the power plant by lowering the Heat Rate. The Los Esteros Project Debt is comprised of a $305 million construction loan facility, an approximately $38 million project letter of credit facility and an approximately $30 million debt service reserve letter of credit facility. The construction loan converts to a ten year term loan when commercial operations commence. Borrowings bear interest initially at LIBOR plus 2.25%. At December 31, 2011,

approximately $83 million had been drawn under the construction loan and approximately $30 million of letters of credit were issued under the letter of credit facilities.

In connection with the closing of the Los Esteros Project Debt, we recorded deferred financing costs of approximately $12 million on our Consolidated Balance Sheet during the year ended December 31, 2011.

CCFC Notes

On May 19, 2009, our wholly owned subsidiaries, CCFC and CCFC Finance, issued approximately $1.0 billion aggregate principal amount of 8.0% CCFC Notes in a private placement. The net proceeds received, together with CCFC cash on hand, were used to repay the CCFC Term Loans and CCFC Old Notes with the remaining cash distributed to CCFC's indirect parent, CCFCP, which was used by CCFCP to redeem its CCFCP Preferred Shares. In connection with the CCFC Refinancing, we recorded deferred financing costs of approximately $21 million on our Consolidated Balance Sheet during the year ended December 31, 2009, and we recorded $49 million in debt extinguishment costs during the year ended December 31, 2009.

The CCFC Notes and the related guarantees are secured, subject to certain exceptions and permitted liens, by all real and personal property of CCFC and CCFC's material subsidiaries (including the CCFC Guarantors), consisting primarily of six natural gas power plants as well as the equity interests in CCFC and the CCFC Guarantors. The CCFC Notes are not guaranteed by Calpine Corporation and are without recourse to Calpine Corporation or any of our other non-CCFC or CCFC Finance subsidiaries or assets; however, CCFC generates the majority of its cash flows from an intercompany tolling agreement with CES and has various service agreements in place with other subsidiaries of Calpine Corporation. The CCFC Notes mature on June 1, 2016 and the weighted average interest rates, which includes the amortization of deferred financing costs and debt discount, was 8.9% for both 2011 and 2010.

Capital Lease Obligations

The following is a schedule by year of future minimum lease payments under capital leases and failed sale-leaseback transactions together with the present value of the net minimum lease payments as of December 31, 2011 (in millions):

	Sale-Leaseback Transactions[1]	Capital Lease	Total
2012	$ 41	$ 40	$ 81
2013	38	38	76
2014	26	39	65
2015	25	37	62
2016	25	40	65
Thereafter	143	200	343
Total minimum lease payments	298	394	692
Less: Amount representing interest	110	170	280
Present value of net minimum lease payments	$ 188	$ 224	$ 412

(1) Amounts are accounted for as financing transactions under U.S. GAAP and are included in our project financing, notes payable and other amounts above.

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 37 years (including lease renewal options). Some of the lease agreements contain customary restrictions on dividends up to Calpine Corporation, additional debt and further encumbrances similar to those typically found in project financing agreements. At both December 31, 2011 and 2010, the asset balances for the leased assets totaled approximately $1.0 billion with accumulated amortization of $340 million and $312 million, respectively. See Note 15 for discussion of capital leases guaranteed by Calpine Corporation.

Corporate Revolving Facility and Other Letters of Credit Facilities

The table below represents amounts issued under our letter of credit facilities as of December 31, 2011 and 2010 (in millions):

	2011	2010
Corporate Revolving Facility[1]	$ 440	$ 443
CDHI[2]	193	165
NDH Project Debt credit facility[3]	—	34
Various project financing facilities	130	69
Total	$ 763	$ 711

(1) When we entered into our $1.0 billion Corporate Revolving Facility on December 10, 2010, the letters of credit issued under our First Lien Credit Facility were either replaced with letters of credit issued under our Corporate Revolving Facility or back-stopped by an irrevocable standby letter of credit issued by a third party. Our letters of credit under our Corporate Revolving Facility at December 31, 2010 include those that were back-stopped of approximately $83 million. The back-stopped letters of credit were returned and extinguished during 2011.

(2) On January 10, 2012, we increased the CDHI letter of credit facility to $300 million and extended the maturity date to January 2, 2016.

(3) We repaid and terminated the NDH Project Debt on March 9, 2011.

The Corporate Revolving Facility represents our primary revolving facility. Borrowings under the Corporate Revolving Facility bear interest, at our option, at either a base rate or LIBOR rate. Base rate borrowings shall be at the base rate, plus an applicable margin ranging from 2.00% to 2.25% as provided in the Corporate Revolving Facility credit agreement. Base rate is defined as the higher of (i) the Federal Funds Effective Rate, as published by the Federal Reserve Bank of New York, plus 0.50% and (ii) the rate the administrative agent announces from time to time as its prime per annum rate. LIBOR rate borrowings shall be at the British Bankers' Association Interest Settlement Rates for the interest period as selected by us as a one, two, three, six or, if agreed by all relevant lenders, nine or twelve month interest period, plus an applicable margin ranging from 3.00% to 3.25%. Interest payments are due on the last business day of each calendar quarter for base rate loans and the earlier of (i) the last day of the interest period selected or (ii) each day that is three months (or a whole multiple thereof) after the first day for the interest period selected for LIBOR rate loans. Letter of credit fees for issuances of letters of credit include fronting fees equal to that percentage per annum as may be separately agreed upon between us and the issuing lenders and a participation fee for the lenders equal to the applicable interest margin for LIBOR rate borrowings. Drawings under letters of credit shall be repaid within two business days or be converted into borrowings as provided in the Corporate Revolving Facility credit agreement. We will incur an unused commitment fee ranging from 0.50% to 0.75% on the unused amount of commitments under the Corporate Revolving Facility.

The Corporate Revolving Facility does not contain any requirements for mandatory prepayments, except in the case of certain designated asset sales in excess of $3 billion in the aggregate. However, we may voluntarily repay, in whole or in part, the Corporate Revolving Facility, together with any accrued but unpaid interest, with prior notice and without premium or penalty. Amounts repaid may be reborrowed, and we may also voluntarily reduce the commitments under the Corporate Revolving Facility without premium or penalty. The Corporate Revolving Facility matures December 10, 2015.

The Corporate Revolving Facility is guaranteed and secured by each of our current domestic subsidiaries that was a guarantor under the First Lien Credit Facility and will also be additionally guaranteed by our future domestic subsidiaries that are required to provide such a guarantee in accordance with the terms of the Corporate Revolving Facility. The Corporate Revolving Facility ranks equally in right of payment with all of our and the guarantors' other existing and future senior indebtedness and will be effectively subordinated in right of payment to all existing and future liabilities of our subsidiaries that do not guarantee the Corporate Revolving Facility. The Corporate Revolving Facility also requires compliance with financial covenants that include a minimum cash interest coverage ratio and a maximum net leverage ratio.

CDHI

We also have a letter of credit facility related to CDHI which matures on December 11, 2012, under which up to $200 million is available for letters of credit. On January 10, 2012, we amended the CDHI letter of credit facility to increase the facility to $300 million and extend the maturity date to January 2, 2016.

Fair Value of Debt

We record our debt instruments based on contractual terms, net of any applicable premium or discount. We did not elect to apply the alternative U.S. GAAP provisions of the fair value option for recording financial assets and financial liabilities. We measured the fair value of our debt instruments as of December 31, 2011 and 2010, using market information including credit default swap rates and historical default information, quoted market prices or dealer quotes for the identical liability when traded as an asset and discounted cash flow analyses based on our current borrowing rates for similar types of borrowing arrangements. The following table details the fair values and carrying values of our debt instruments as of December 31, 2011 and 2010 (in millions):

	2011		2010	
	Fair Value	Carrying Value	Fair Value	Carrying Value
First Lien Notes	$ 6,219	$ 5,892	$ 4,695	$ 4,691
Project financing, notes payable and other[(1)]	1,467	1,504	1,673	1,708
Term Loan and New Term Loan	1,615	1,646	—	—
CCFC Notes	1,070	972	1,067	965
NDH Project Debt	—	—	1,303	1,258
First Lien Credit Facility	—	—	1,182	1,184
Total	$ 10,371	$ 10,014	$ 9,920	$ 9,806

(1) Excludes leases that are accounted for as failed sale-leaseback transactions under U.S. GAAP and included in our project financing, notes payable and other balance.

7. Assets and Liabilities with Recurring Fair Value Measurements

Cash Equivalents — Highly liquid investments which meet the definition of cash equivalents, primarily investments in money market accounts, are included in both our cash and cash equivalents and in restricted cash on our Consolidated Balance Sheets. 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. Our cash equivalents are classified within level 1 of the fair value hierarchy.

Margin Deposits and Margin Deposits Held by Us Posted by Our Counterparties — Margin deposits and margin deposits held by us posted by our counterparties represent cash collateral paid between our counterparties and us to support our commodity contracts. Our margin deposits and margin deposits held by us posted by our counterparties are generally cash and cash equivalents and are classified within level 1 of the fair value hierarchy.

Derivatives — The primary factors affecting the fair value of our derivative instruments at any point in time are the volume of open derivative positions (MMBtu, MWh and $ notional amounts); market price levels, primarily for power and natural gas; our credit standing and that of our counterparties; and prevailing interest rates for our interest rate swaps. Prices for power and natural gas and interest rates are volatile, which can result in material changes in the fair value measurements reported in our financial statements in the future.

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

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

Our level 2 fair value derivative instruments primarily consist of interest rate swaps and OTC power and natural gas forwards for which market-based pricing inputs are observable. Generally, we obtain our level 2 pricing inputs from market sources such as the Intercontinental Exchange and Bloomberg. To the extent we obtain prices from brokers in the marketplace, we have procedures in place to ensure that prices represent executable prices for market participants. 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, correlation, volatility, as well as other relevant economic measures. Substantially all of these assumptions are observable in the marketplace throughout the full term of the instrument, can be derived from observable data or are supported by observable levels at which transactions are executed in the marketplace.

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

The following tables present our financial assets and liabilities that were accounted for at fair value on a recurring basis as of December 31, 2011 and 2010, by level within the fair value hierarchy. Financial assets and liabilities are classified in their entirety based on the lowest level of input that is significant to the fair value measurement. Our assessment of the significance of a particular input to the fair value measurement requires judgment and may affect our estimate of the fair value of our assets and liabilities and their placement within the fair value hierarchy levels.

	Assets and Liabilities with Recurring Fair Value Measures as of December 31, 2011			
	Level 1	Level 2	Level 3	Total
	(in millions)			
Assets:				
Cash equivalents[1]	$ 1,415	$ —	$ —	$ 1,415
Margin deposits	140	—	—	140
Commodity instruments:				
Commodity futures contracts	1,043	—	—	1,043
Commodity forward contracts[2]	—	74	37	111
Interest rate swaps	—	10	—	10
Total assets	$ 2,598	$ 84	$ 37	$ 2,719
Liabilities:				
Margin deposits held by us posted by our counterparties	$ 34	$ —	$ —	$ 34
Commodity instruments:				
Commodity futures contracts	899	—	—	899
Commodity forward contracts[2]	—	184	20	204
Interest rate swaps	—	320	—	320
Total liabilities	$ 933	$ 504	$ 20	$ 1,457

	Assets and Liabilities with Recurring Fair Value Measures as of December 31, 2010			
	Level 1	Level 2	Level 3	Total
	(in millions)			
Assets:				
Cash equivalents[1]	$ 1,297	$ —	$ —	$ 1,297
Margin deposits	162	—	—	162
Commodity instruments:				
Commodity futures contracts	550	—	—	550
Commodity forward contracts[2]	—	287	54	341
Interest rate swaps	—	4	—	4
Total assets	$ 2,009	$ 291	$ 54	$ 2,354
Liabilities:				
Margin deposits held by us posted by our counterparties	$ 6	$ —	$ —	$ 6
Commodity instruments:				
Commodity futures contracts	574	—	—	574
Commodity forward contracts[2]	—	119	24	143
Interest rate swaps	—	371	—	371
Total liabilities	$ 580	$ 490	$ 24	$ 1,094

(1) As of December 31, 2011 and 2010, we had cash equivalents of $1,249 million and $1,094 million included in cash and cash equivalents and $166 million and $203 million included in restricted cash, respectively.

(2) Includes OTC swaps and options.

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 years ended December 31, 2011, 2010 and 2009 (in millions):

	2011	2010	2009
Balance, beginning of period	$ 30	$ 38	$ 105
Realized and unrealized gains (losses):			
Included in net income:			
Included in operating revenues[1]	5	7	14
Included in fuel and purchased energy expense[2]	—	—	5
Included in OCI	2	2	(4)
Purchases, issuances and settlements:			
Settlements	(18)	(20)	(48)
Transfers in and/or out of level 3[3]:			
Transfers into level 3[4]	(2)	—	—
Transfers out of level 3[5]	—	3	(34)
Balance, end of period	$ 17	$ 30	$ 38
Change in unrealized gains relating to instruments still held at end of period[2]	$ 5	$ 7	$ 19

(1) For power contracts and Heat Rate swaps and options, included on our Consolidated Statements of Operations.

(2) For natural gas contracts, swaps and options, included on our Consolidated Statements of Operations.

(3) We transfer amounts among levels of the fair value hierarchy as of the end of each period. There were no significant transfers into/out of level 1 during the years ended December 31, 2011, 2010 and 2009.

(4) We had $2 million in losses transferred out of level 2 into level 3 for the year ended December 31, 2011, due to changes in market liquidity in various power and natural gas markets.There were no significant transfers into level 3 for the years ended December 31, 2010 and 2009.

(5) There were no significant transfers out of level 3 for the year ended 2011. We had $3 million in losses and $(34) million in (gains) transferred out of level 3 into level 2 for the years ended December 31, 2010 and 2009, respectively, due to changes in market liquidity in various power markets.

8. Derivative Instruments

Types of Derivative Instruments and Volumetric Information

Commodity Instruments — We are exposed to changes in prices for the purchase and sale of power, natural gas and other energy commodities. We use derivatives, which include physical commodity contracts and financial commodity instruments such as OTC and exchange traded swaps, futures, options, forward agreements and instruments that settle on the power price to natural gas price relationships (Heat Rate swaps and options) or instruments that settle on power price relationships between delivery points for the purchase and sale of power and natural gas to attempt to maximize the risk-adjusted returns by economically hedging a portion of the commodity price risk associated with our assets. By entering into these transactions, we are able to economically hedge a portion of our Spark Spread at estimated generation and prevailing price levels.

Interest Rate Swaps — A portion of our debt is indexed to base rates, primarily LIBOR. We have historically used interest rate swaps to adjust the mix between fixed and floating rate debt to hedge our interest rate risk for potential adverse changes in interest rates.

As of December 31, 2011, the maximum length of our PPAs extend approximately 23 years into the future and the maximum length of time over which we were hedging using commodity and interest rate derivative cash flow hedging instruments was 1 and 12 years, respectively.

As of December 31, 2011 and 2010, the net forward notional buy (sell) position of our outstanding commodity and interest rate swap contracts that did not qualify under the normal purchase normal sale exemption were as follows (in millions):

Derivative Instruments	Notional Amounts	
	2011	2010
Power (MWh)	(21)	(50)
Natural gas (MMBtu)	(200)	31
Interest rate swaps[(1)]	$ 5,639	$ 6,171

(1) Approximately $4.1 billion and $3.3 billion at December 31, 2011 and 2010, respectively, related to variable rate debt that was converted to fixed rate debt in 2011 and 2010.

Certain of our derivative instruments contain credit-contingent provisions that require us to maintain a minimum credit rating from each of the major credit rating agencies. If our credit rating were to be downgraded, it could require us to post additional collateral or could potentially allow our counterparty to request immediate, full settlement on certain derivative instruments in liability positions. Currently, we do not believe that it is probable that any additional collateral posted as a result of a one credit downgrade would be material. The aggregate fair value of our derivative liabilities with credit-contingent provisions as of December 31, 2011, was $138 million for which we have posted collateral of $90 million by posting margin deposits or granted additional first priority liens on the assets currently subject to first priority liens under our First Lien Notes, Corporate Revolving Facility, Term Loan and New Term Loan. However, if our credit rating were downgraded, we estimate that additional collateral of $2 million would be required and that no counterparty could request immediate, full settlement.

Accounting for Derivative Instruments

We recognize all derivative instruments that qualify for derivative accounting treatment as either assets or liabilities and measure those instruments at fair value unless they qualify for, and we elect, the normal purchase normal sale exemption. For transactions in which we elect the normal purchase normal sale exemption, gains and losses are not reflected on our Consolidated Statements of Operations until the period of delivery. Revenues and fuel costs derived from instruments that qualify for hedge accounting or represent an economic hedge are recorded in the same financial statement line item as the item being hedged. Hedge accounting requires us to formally document, designate and assess the effectiveness of transactions that receive hedge accounting. We present the cash flows from our derivatives in the same category as the item being hedged (or economically hedged) within operating activities or investing activities (in the case of settlements for our interest rate swaps formerly hedging our First Lien Credit Facility term loans or interest rate swap breakage costs associated with interest rate swaps formerly hedging project debt) 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.

Cash Flow Hedges — We report the effective portion of the unrealized gain or loss on a derivative instrument designated and qualifying as a cash flow hedging instrument as a component of OCI and reclassify such gains and losses into earnings in the same period during which the hedged forecasted transaction affects earnings. Gains and losses due to ineffectiveness on commodity hedging instruments are recognized currently in earnings as a component of operating revenues (for power contracts and swaps), fuel and purchased energy expense (for natural gas contracts and swaps) and interest expense (for interest rate swaps except as discussed below). If it is determined that the forecasted transaction is no longer probable of occurring, then hedge accounting will be discontinued prospectively and future changes in fair value are recorded in earnings. If the hedging instrument is terminated or de-designated prior to the occurrence of the hedged forecasted transaction, the net accumulated gain or loss associated with the changes in fair value of the hedge instrument remains deferred in AOCI until such time as the forecasted transaction impacts earnings or until it is determined that the forecasted transaction is probable of not occurring. Upon repayment of our NDH Project Debt and other project debt, we terminated and settled the interest rate swaps related to these debt instruments and recorded $17 million to loss on interest rate derivatives during 2011. See Note 6 for further information about the repayment of the NDH Project Debt as well as the repayment of other project debt with proceeds from our New Term Loan.

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

Interest Rate Swaps Formerly Hedging our First Lien Credit Facility and Other Project Debt — During 2010, we repaid approximately $3.5 billion of our First Lien Credit Facility term loans, which had approximately $3.3 billion notional amount of interest rate swaps hedging the scheduled variable interest payments, and in January 2011, we repaid the remaining approximately $1.2 billion of First Lien Credit Facility term loans which had approximately $1.0 billion notional amount of interest rate swaps hedging the scheduled variable interest payments. With the repayment of the remaining First Lien Credit Facility term loans, the remaining unrealized losses of approximately $91 million in AOCI related to the interest rate swaps formerly hedging the First Lien Credit Facility, were reclassified out of AOCI and into income as an additional loss on interest rate derivatives during 2011. In addition, we reclassified approximately $17 million in unrealized losses in AOCI to loss on interest rate derivatives during 2011 resulting from the repayment of project debt in 2011. During 2010, we reclassified approximately $206 million out of AOCI and into income as additional loss on interest rate derivatives related to interest rate swaps formerly hedging our First Lien Credit Facility term loans. We have presented the reclassification of unrealized losses from AOCI into income and the changes in fair value and settlements subsequent to the reclassification date of the interest rate swaps formerly hedging our First Lien Credit Facility described above separate from interest expense as loss on interest rate derivatives on our Consolidated Statements of Operations. We also have determined that, based upon current market conditions and consistent with our Risk Management Policy, liquidation of these interest rate swaps is not economically beneficial and additional future losses are limited. Accordingly, we have elected to retain and hold these interest rate swap positions at this time. The interest rate swaps formerly hedging our First Lien Credit Facility term loans substantially mature in 2012.

Derivatives Included on Our Consolidated Balance Sheet

The following tables present the fair values of our net derivative instruments recorded on our Consolidated Balance Sheets by location and hedge type at December 31, 2011 and 2010 (in millions):

	December 31, 2011		
	Interest Rate Swaps	Commodity Instruments	Total Derivative Instruments
Balance Sheet Presentation			
Current derivative assets	$ —	$ 1,051	$ 1,051
Long-term derivative assets	10	103	113
Total derivative assets	$ 10	$ 1,154	$ 1,164
Current derivative liabilities	$ 166	$ 978	$ 1,144
Long-term derivative liabilities	154	125	279
Total derivative liabilities	$ 320	$ 1,103	$ 1,423
Net derivative assets (liabilities)	$ (310)	$ 51	$ (259)

	December 31, 2010		
	Interest Rate Swaps	Commodity Instruments	Total Derivative Instruments
Balance Sheet Presentation			
Current derivative assets	$ —	$ 725	$ 725
Long-term derivative assets	4	166	170
Total derivative assets	$ 4	$ 891	$ 895
Current derivative liabilities	$ 197	$ 521	$ 718
Long-term derivative liabilities	174	196	370
Total derivative liabilities	$ 371	$ 717	$ 1,088
Net derivative assets (liabilities)	$ (367)	$ 174	$ (193)

	December 31, 2011		December 31, 2010	
	Fair Value of Derivative Assets	Fair Value of Derivative Liabilities	Fair Value of Derivative Assets	Fair Value of Derivative Liabilities
Derivatives designated as cash flow hedging instruments:				
Interest rate swaps	$ 10	$ 149	$ 2	$ 143
Commodity instruments	51	18	161	52
Total derivatives designated as cash flow hedging instruments	$ 61	$ 167	$ 163	$ 195
Derivatives not designated as hedging instruments:				
Interest rate swaps	$ —	$ 171	$ 2	$ 228
Commodity instruments	1,103	1,085	730	665
Total derivatives not designated as hedging instruments	$ 1,103	$ 1,256	$ 732	$ 893
Total derivatives	$ 1,164	$ 1,423	$ 895	$ 1,088

Derivatives Included on Our Consolidated Statements of Operations

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

The following tables detail the components of our total mark-to-market activity for both the net realized gain (loss) and the net unrealized gain (loss) recognized from our derivative instruments not designated as hedging instruments and where these components were recorded on our Consolidated Statements of Operations for the years ended December 31, 2011, 2010 and 2009 (in millions):

	2011	2010	2009
Realized gain (loss)			
Interest rate swaps	$ (193)	$ (31)	$ (32)
Commodity derivative instruments	143	114	37
Total realized gain (loss)	$ (50)	$ 83	$ 5
Unrealized gain (loss)[(1)]			
Interest rate swaps	$ 55	$ (199)	$ 8
Commodity derivative instruments	(25)	143	79
Total unrealized gain (loss)	$ 30	$ (56)	$ 87
Total mark-to-market activity, net	$ (20)	$ 27	$ 92

(1) In addition to changes in market value on derivatives not designated as hedges, changes in unrealized gain (loss) also includes de-designation of interest rate swap cash flow hedges and related reclassification from AOCI into income, hedge ineffectiveness and adjustments to reflect changes in credit default risk exposure.

	2011	2010	2009
Realized and unrealized gain (loss)			
Power contracts included in operating revenues	$ (20)	$ (19)	$ 7
Natural gas contracts included in fuel and purchased energy expense	138	276	109
Interest rate swaps included in interest expense	7	(7)	(24)
Loss on interest rate derivatives	(145)	(223)	—
Total mark-to-market activity, net	$ (20)	$ 27	$ 92

Derivatives Included in OCI and AOCI

The following table details the effect of our net derivative instruments that qualified for hedge accounting treatment and are included in OCI and AOCI for the years ended December 31, 2011 and 2010 (in millions):

	Gains (Loss) Recognized in OCI (Effective Portion)		Gain (Loss) Reclassified from AOCI into Income (Effective Portion)[2]		Gain (Loss) Reclassified from AOCI into Income (Ineffective Portion)	
	2011	2010	2011	2010	2011	2010
Interest rate swaps	$ (23)	$ 193	$ (138) [3]	$ (389) [4]	$ (1)	$ —
Commodity derivative instruments	(71)	(27)	163 [1]	248 [1]	(2)	—
Total	$ (94)	$ 166	$ 25	$ (141)	$ (3)	$ —

(1) Included in operating revenues and fuel and purchased energy expense on our Consolidated Statement of Operations.

(2) Cumulative cash flow hedge losses, net of tax, remaining in AOCI were $172 million and $122 million at December 31, 2011 and 2010, respectively. Our other components of AOCI were not material at December 31, 2011 and 2010.

(3) Reclassification of losses from OCI to earnings consisted of $32 million in losses from the reclassification of interest rate contracts due to settlement, $15 million in losses from terminated interest rate contracts due to the repayment of project debt in 2011, and $91 million in losses from existing interest rate contracts reclassified from OCI into earnings due to the refinancing of variable rate First Lien Credit Facility term loans.

(4) Reclassification of losses from OCI to earnings consisted of $183 million in losses from the reclassification of interest rate contracts due to settlement and $206 million in losses from interest rate contracts reclassified from OCI into earnings due to the refinancing of variable rate First Lien Credit Facility term loans.

Assuming constant December 31, 2011 power and natural gas prices and interest rates, we estimate that pre-tax net gains of $15 million would be reclassified from AOCI into earnings during the next 12 months as the hedged transactions settle; however, the actual amounts that will be reclassified will likely vary based on changes in natural gas and power prices as well as interest rates. Therefore, we are unable to predict what the actual reclassification from AOCI into earnings (positive or negative) will be for the next 12 months.

9. Use of Collateral

We use margin deposits, prepayments and letters of credit as credit support with and from our counterparties for commodity procurement and risk management activities. In addition, we have granted additional first priority liens on the assets currently subject to first priority liens under various debt agreements as collateral under certain of our power and natural gas agreements 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 share the benefits of the collateral subject to such first priority liens pro rata with the lenders under our various debt agreements.

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, 2011 and 2010 (in millions):

	2011	2010
Margin deposits[1]	$ 140	$ 162
Natural gas and power prepayments	42	43
Total margin deposits and natural gas and power prepayments with our counterparties[2]	$ 182	$ 205
Letters of credit issued[3]	$ 581	$ 588
First priority liens under power and natural gas agreements[4]	1	—
First priority liens under interest rate swap agreements	318	391
Total letters of credit and first priority liens with our counterparties	$ 900	$ 979
Margin deposits held by us posted by our counterparties[1][5]	$ 34	$ 6
Letters of credit posted with us by our counterparties	—	66
Total margin deposits and letters of credit posted with us by our counterparties	$ 34	$ 72

(1) Balances are subject to master netting arrangements and presented on a gross basis on our Consolidated Balance Sheets. We do not offset fair value amounts recognized for derivative instruments executed with the same counterparty under a master netting arrangement for financial statement presentation.

(2) At December 31, 2011 and 2010, $162 million and $183 million, respectively, were included in margin deposits and other prepaid expense and $20 million and $22 million were included in other assets at December 31, 2011 and 2010, respectively, on our Consolidated Balance Sheets.

(3) When we entered into our Corporate Revolving Facility on December 10, 2010, the letters of credit issued under our First Lien Credit Facility were either replaced by letters of credit issued under the Corporate Revolving Facility or back-stopped by an irrevocable standby letter of credit issued by a third party. Our letters of credit issued under our Corporate Revolving Facility used for our commodity procurement and risk management activities as of December 31, 2010 include those that were back-stopped of approximately $63 million. The back-stopped letters of credit were returned and extinguished during the first quarter of 2011.

(4) At December 31, 2010, the fair value of our commodity derivative instruments collateralized by first priority liens was an asset of $193 million; therefore, there was no collateral exposure at December 31, 2010.

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

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

10. Income Taxes

Income Tax Expense (Benefit)

The jurisdictional components of income (loss) from continuing operations before income tax expense (benefit), attributable to Calpine, for the years ended December 31, 2011, 2010 and 2009, are as follows (in millions):

	2011	2010	2009
U.S.	$ (232)	$ (226)	$ 116
International	20	(4)	13
Total	$ (212)	$ (230)	$ 129

The components of income tax expense (benefit) from continuing operations for the years ended December 31, 2011, 2010 and 2009, consisted of the following (in millions):

	2011	2010	2009
Current:			
Federal	$ (16)	$ (1)	$ (2)
State	12	10	(2)
Foreign	3	3	3
Total current	(1)	12	(1)
Deferred:			
Federal	(33)	(70)	13
State	9	—	4
Foreign	3	(10)	(1)
Total deferred	(21)	(80)	16
Total income tax expense (benefit)	$ (22)	$ (68) [1]	$ 15

(1) Includes approximately $13 million in intraperiod tax expense related to a prior period with an offsetting benefit in OCI.

For the years ended December 31, 2011, 2010 and 2009, our income tax rates did not bear a customary relationship to statutory income tax rates, primarily as a result of the impact of our valuation allowance, state income taxes and changes in unrecognized tax benefits. A reconciliation of the federal statutory rate of 35% to our effective rate from continuing operations for the years ended December 31, 2011, 2010 and 2009, is as follows:

	2011	2010	2009
Federal statutory tax expense (benefit) rate	(35.0)%	(35.0)%	35.0%
State tax expense (benefit), net of federal benefit	6.5	2.8	1.0
Depletion in excess of basis	—	(1.3)	—
Valuation allowances against future tax benefits	56.7	33.6	(139.2)
Valuation allowances related to reconsolidation of CCFC	(36.0)	—	—
Foreign taxes	(0.9)	9.9	(9.2)
Non-deductible reorganization items	0.5	0.3	1.3
Income from cancellation of indebtedness	—	—	69.0
Intraperiod allocation	19.9	(40.1)	45.4
Bankruptcy settlement	(15.7)	—	—
Change in unrecognized tax benefits	(6.6)	0.6	1.4
Permanent differences and other items	0.2	(0.4)	6.9
Effective income tax expense (benefit) rate	(10.4)%	(29.6)%	11.6%

Deferred Tax Assets and Liabilities

The components of the deferred income taxes as of December 31, 2011 and 2010, are as follows (in millions):

	2011	2010
Deferred tax assets:		
NOL and credit carryforwards	$ 3,290	$ 3,138
Taxes related to risk management activities and derivatives	58	18
Reorganization items and impairments	318	422
Foreign capital losses	24	25
Other differences	26	12
Deferred tax assets before valuation allowance	3,716	3,615
Valuation allowance	(2,336)	(2,386)
Total deferred tax assets	1,380	1,229
Deferred tax liabilities: property, plant and equipment	(1,364)	(1,280)
Net deferred tax asset (liability)	16	(51)
Less: Current portion deferred tax asset (liability)	(2)	(4)
Less: Non-current deferred tax asset	18	30
Deferred income tax liability, non-current	$ —	$ (77)

Consolidation of CCFC and Calpine Tax Reporting Groups — For federal income tax reporting purposes, our historical tax reporting group was comprised primarily of two separate groups, CCFC and its subsidiaries, which we referred to as the CCFC group, and Calpine Corporation and its subsidiaries other than CCFC, which we referred to as the Calpine group. During the first quarter of 2011, we elected to consolidate our CCFC and Calpine groups for federal income tax reporting purposes and Calpine will file a consolidated federal income tax return for the year ended December 31, 2011 that will include the CCFC group. As a result of the consolidation, the CCFC group deferred tax liabilities will be eligible to offset existing Calpine group NOLs that were reserved by a valuation allowance. Accordingly, we recorded a one-time federal deferred income tax benefit of approximately $76 million during the first quarter of 2011 to reduce our valuation allowance. For the years ended December 31, 2010 and 2009, the CCFC group was deconsolidated from the Calpine group for federal income tax reporting purposes.

Intraperiod Tax Allocation — In accordance with U.S. GAAP, intraperiod tax allocation provisions require allocation of a tax expense (benefit) to continuing operations due to current OCI gains (losses) and income from discontinued operations with a partial offsetting amount recognized in OCI and discontinued operations. The following table details the effects of our intraperiod tax allocations for the year ended December 31, 2011, 2010 and 2009 (in millions).

	2011	2010	2009
Intraperiod tax allocation expense (benefit) included in continuing operations	$ 42	$ (86)	$ 43
Intraperiod tax allocation expense (benefit) included in discountinued operations	$ —	$ 59	$ —
Intraperiod tax allocation expense (benefit) included in OCI	$ (45)	$ 27	$ (43)

NOL Carryforwards — Our NOL carryforwards consist primarily of federal NOL carryforwards of approximately $7.9 billion, which expire between 2023 and 2031, and NOL carryforwards in 33 states and the District of Columbia totaling approximately $4.2 billion, which expire between 2012 and 2032, substantially all of which are offset with a full valuation allowance. We also have approximately $1.0 billion in foreign NOLs, substantially all of which are offset with a full valuation allowance. The NOL carryforwards available are subject to limitations on their annual usage. 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. Under federal income tax law, our NOL carryforwards can be utilized to reduce future taxable income subject to certain limitations, including if we were to undergo an ownership change as defined by Section 382 of 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 our Plan of Reorganization. However, this ownership change and the resulting annual limitations are not expected to result in the expiration of our NOL carryforwards if we are able to generate sufficient future taxable income within the carryforward periods. At December 31, 2011, approximately $2.4 billion of our $7.9 billion federal NOLs are not subject to annual Section 382 limitations. When considering our cumulative annual Section 382 limitations, in addition to our post-Effective Date NOLs that are not limited, our total unrestricted NOLs are

approximately $6.3 billion. If a subsequent ownership change were to occur as a result of future transactions in our common 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.

Under state income tax laws, our NOL carryforwards can be utilized to reduce future taxable income subject to certain limitations, including if we were to undergo an ownership change as defined by Section 382 of the IRC. During 2011, we analyzed the effect of our change in ownership on the Effective Date for each of our significant states to determine the amount of our NOL limitation. The analysis determined that $640 million of our state NOLs are expected to expire unutilized as a result of statutory limitations on the use of some of our pre-emergence state NOLs as of the Effective Date or the cessation of business operations in various tax jurisdictions. We reduced our deferred tax asset for state NOLs that we are unable to utilize and made an equal reduction in our valuation allowance. The result did not have an impact on our income tax expense in 2011. In 2012 we will continue with our analysis and adjust our state NOLs where appropriate.

To manage the risk of significant limitations on our ability to utilize our tax NOL carryforwards, our amended and restated certificate of incorporation requires our Board of Directors to meet to determine whether to impose certain transfer restrictions on our common stock if, prior to February 1, 2013, our Market Capitalization declines by at least 35% from our Emergence Date Market Capitalization of approximately $8.6 billion (in each case, as defined in and calculated pursuant to our amended and restated certificate of incorporation) and at least 25 percentage points of shift in ownership has occurred with respect to our equity for purposes of Section 382 of the IRC. We believe as of the filing of this Report, neither circumstance was met. Accordingly, the transfer restrictions have not been put in place by our Board of Directors; however, if both of the foregoing events were to occur together and our Board of Directors was to elect to impose them, they could become operative in the future. 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.

Should our Board of Directors elect to impose these restrictions, it will have the authority and discretion to determine and establish the definitive terms of the transfer restrictions, provided that the transfer restrictions apply to purchases by owners of 5% or more of our common stock, including any owners who would become owners of 5% or more of our common stock via such purchase. The transfer restrictions will not apply to the disposition of shares provided they are not purchased by a 5% or more owner.

We had certain intercompany accounts payable/receivable balances that were eliminated as part of the final steps of our emergence from bankruptcy. There was no effect to our federal NOLs, however, there was a reduction in our state NOLs of $44 million which was partially offset by a reduction in current state taxable income of $24 million. The resulting net reduction to our state NOLs was offset by an equal reduction in our valuation allowance. The reduction did not have an impact on our income tax expense in 2011.

As a result of the settlement with holders of the CalGen Third Lien Debt and the final distribution to the holders of allowed unsecured claims in accordance with our Plan of Reorganization in 2011, we recognized approximately $66 million and $39 million for federal and state income tax purposes, respectively, in cancellation of debt income related to this distribution for federal income tax reporting.

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

Canadian Tax Audits — In September 2009, we received notice from the Canadian Revenue Authority, or CRA, of their intent to conduct a limited scope income tax audit on four of our Canadian subsidiaries for the tax years 2005 through 2008. CRA concluded that there were no adjustments on two of the entities but further review was required on the remaining two entities. We have timely provided all supporting documentation and any additional documents requested by the CRA on the remaining two entities, and we believe that the CRA will conclude their audit within the first six months of 2012. Although no formal assessment has been received, based on recent communications, we believe that the CRA may be planning a reassessment; however, we are not currently aware of the nature or amount of the adjustments, if any, and accordingly we have not established a tax reserve. If a reassessment should occur, any adjustment to taxable income would first be offset against any existing NOLs that are available. At this time, we are unable to determine the likelihood whether the outcome would have a material adverse effect on our financial position, results of operations or cash flow.

Valuation Allowance — U.S. GAAP requires that we consider all available evidence, both positive and negative, and tax planning strategies to determine whether, based on the weight of that evidence, a valuation allowance is needed to reduce the value of deferred tax assets. 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, since our emergence from Chapter 11, we are able to consider available tax planning strategies.

As of December 31, 2011, we have provided a valuation allowance of approximately $2.3 billion on certain federal, state and foreign tax jurisdiction deferred tax assets to reduce the amount of these assets to the extent necessary to result in an amount that is more likely than not to be realized. The net change in our valuation allowance was a decrease of $50 million, $186 million and $113 million for the years ended December 31, 2011, 2010 and 2009, respectively; all primarily related to changes in our estimates of our ability to utilize our NOL carryforwards.

Unrecognized Tax Benefits

At December 31, 2011, we had unrecognized tax benefits of $74 million. If recognized, $28 million of our unrecognized tax benefits could impact the annual effective tax rate and $46 million related to deferred tax assets could be offset against the recorded valuation allowance resulting in no impact to our effective tax rate. We also had accrued interest and penalties of $20 million for income tax matters at December 31, 2011. We recognize interest and penalties related to unrecognized tax benefits in income tax expense (benefit). A reconciliation of the beginning and ending amounts of our unrecognized tax benefits for the years ended December 31, 2011, 2010 and 2009, is as follows (in millions):

	2011	2010	2009
Balance, beginning of period	$ (88)	$ (98)	$ (90)
Increases related to prior year tax positions	—	(1)	(11)
Decreases related to prior year tax positions	1	11	2
Settlements	—	—	1
Decrease related to lapse of statute of limitations	13	—	—
Balance, end of period	$ (74)	$ (88)	$ (98)

11. Earnings (Loss) per Share

Pursuant to our Plan of Reorganization, all shares of our common stock outstanding prior to the Effective Date were canceled and the issuance of 485 million new shares of reorganized Calpine Corporation common stock was authorized to resolve allowed unsecured claims. A portion of the 485 million authorized shares was immediately distributed, and the remainder was reserved for distribution to holders of certain disputed claims that, although allowed as of the Effective Date, were unresolved. In June 2011, we settled the largest remaining claim outstanding and began the process of distributing the balance of the reserved shares, which was completed during the third quarter of 2011, pursuant to our Plan of Reorganization. Accordingly, although the reserved shares were not issued and outstanding for the balance of the periods presented, all conditions of distribution had been met for these reserved shares as of the Effective Date, and such shares are considered issued and are included in our calculation of weighted average shares outstanding. We also include restricted stock units for which no future service is required as a condition to the delivery of the underlying common stock in our calculation of weighted average shares outstanding.

As we incurred a net loss for the year ended December 31, 2011, diluted loss per share for this period is computed on the same basis as basic loss per share, as the inclusion of any other potential shares outstanding would be anti-dilutive.

Reconciliations of the amounts used in the basic and diluted earnings (loss) per common share computations for the years ended December 31, 2011, 2010 and 2009, are as follows (shares in thousands):

	2011	2010	2009
Diluted weighted average shares calculation:			
Weighted average shares outstanding (basic)	485,381	486,044	485,659
Share-based awards	—	1,250	660
Weighted average shares outstanding (diluted)	485,381	487,294	486,319

We excluded the following items from diluted earnings (loss) per common share for the years ended December 31, 2011, 2010 and 2009 because they were anti-dilutive (shares in thousands):

	2011	2010	2009
Share-based awards	15,260	14,883	13,158

12. Stock-Based Compensation

Calpine Equity Incentive Plans

The Calpine Equity Incentive Plans provide for the issuance of equity awards to all non-union 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 share-based awards. The equity awards granted under the Calpine Equity Incentive Plans include both graded and cliff vesting options which vest over periods between one and five years, contain contractual terms between approximately five and ten years and are subject to forfeiture provisions under certain circumstances, including termination of employment prior to vesting. At December 31, 2011, there were 567,000 and 27,533,000 shares of our common stock authorized for issuance to participants under the Director Plan and the Equity Plan, respectively.

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

Stock-based compensation expense recognized was $24 million, $24 million and $38 million for the years ended December 31, 2011, 2010 and 2009, respectively. We did not record any significant tax benefits related to stock-based compensation expense in any period as we are not benefiting from a significant portion of our deferred tax assets, including deductions related to stock-based compensation expense. In addition, we did not capitalize any stock-based compensation expense as part of the cost of an asset for the years ended December 31, 2011, 2010 and 2009. At December 31, 2011, there was unrecognized compensation cost of $12 million related to options, $16 million related to restricted stock and nil related to restricted stock units, which is expected to be recognized over a weighted average period of 1.3 years for options, 1.3 years for restricted stock and 0.4 years for restricted stock units. We issue new shares from our share reserves set aside for the Calpine Equity Incentive Plans and employment inducement options when stock options are exercised and for other share-based awards.

A summary of all of our non-qualified stock option activity for the Calpine Equity Incentive Plans for the year ended December 31, 2011, is as follows:

	Number of Shares	Weighted Average Exercise Price	Weighted Average Remaining Term (in years)	Aggregate Intrinsic Value (in millions)
Outstanding — December 31, 2010	17,164,890	$ 17.44	5.6	$ 8
Granted	953,467	$ 14.27		
Exercised	7,554	$ 11.66		
Forfeited	197,316	$ 13.04		
Expired	247,585	$ 17.56		
Outstanding — December 31, 2011	17,665,902	$ 17.32	4.8	$ 26
Exercisable — December 31, 2011	8,297,284	$ 19.49	4.6	$ 2
Vested and expected to vest – December 31, 2011	17,377,738	$ 17.39	4.7	$ 25

The total intrinsic value and the cash proceeds received from our employee stock options exercised were not significant for the years ended December 31, 2011 and 2010. There were no employee stock options exercised during the year ended December 31, 2009.

The fair value of options granted during the years ended December 31, 2011, 2010 and 2009, was determined on the grant date using the Black-Scholes option-pricing model or the Monte Carlo simulation model, as appropriate. Certain assumptions were used in order to estimate fair value for options as noted in the following table.

	2011	2010	2009
Expected term (in years)[1]	6.5	4.0 – 6.5	6.0 – 6.5
Risk-free interest rate[2]	1.7 – 3.2 %	1.3 – 3.3 %	2.3 – 2.9 %
Expected volatility[3]	31.2 – 44.9 %	31.4 – 37.6 %	52.1 – 73.0 %
Dividend yield[4]	—	—	—
Weighted average grant-date fair value (per option)	$ 5.49	$ 1.98	$ 5.67

(1) Expected term calculated using the simplified method prescribed by the SEC due to the lack of sufficient historical exercise data to provide a reasonable basis to estimate the expected term.

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

(3) Volatility calculated using the implied volatility of our exchange traded stock options.

(4) We have never paid cash dividends on our common stock, and it is not anticipated that any cash dividends will be paid on our common stock in the near future.

No restricted stock or restricted stock units have been granted other than under the Calpine Equity Incentive Plans. A summary of our restricted stock and restricted stock unit activity for the Calpine Equity Incentive Plans for the year ended December 31, 2011, is as follows:

	Number of Restricted Stock Awards	Weighted Average Grant-Date Fair Value
Nonvested — December 31, 2010	2,683,117	$ 11.16
Granted	1,636,026	$ 14.37
Forfeited	322,034	$ 12.32
Vested	486,751	$ 14.41
Nonvested — December 31, 2011	3,510,358	$ 12.10

The total fair value of our restricted stock that vested during the years ended December 31, 2011, 2010 and 2009, was approximately $7 million, $4 million and $8 million, respectively.

13. Defined Contribution and Defined Benefit 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 approximately $10 million, $9 million and $9 million for the years ended December 31, 2011, 2010 and 2009, respectively. Employer matching contributions are 100% of the first 5% of compensation a participant defers for the non-union plan. The employee deferral limit is 75% of compensation under both plans.

As part of the Conectiv Acquisition, we assumed approximately $6 million of pension liability for approximately 130 grandfathered union employees who joined Calpine as a result of the Conectiv Acquisition and enrolled them into the New Development Holdings, LLC Union Retirement Plan, a defined benefit plan. PHI retained the pension liability associated with past service cost; however we are responsible for benefits for services after July 1, 2010 and future compensation increases related to past service. During the second half of 2010, we initiated a voluntary retirement incentive program which reduced our pension obligation by 31 employees. Under the New Development Holdings, LLC Union Retirement Plan, retirement benefits are primarily a function of age attained, years of participation, years of service, vesting and level of compensation. As of December 31, 2011 and 2010, our pension assets, liabilities and related costs were not material to us. As of December 31, 2011 and 2010, there were approximately $10 million and $8 million in plan assets and approximately $18 million and $15 million in pension liabilities, respectively. Our net pension liability recorded on our Consolidated Balance Sheets as of December 31, 2011 and 2010, was approximately $8 million and $7 million, respectively. For the years ended December 31, 2011 and 2010, we recognized net periodic benefit costs of approximately $1 million and $9 million, respectively. Net pension benefit costs for 2010 includes a one-time charge to pension expense for a voluntary retirement incentive program of approximately $8 million. The voluntary retirement incentive program was accepted by 31 of the 48 eligible employees that were retained as part of the Conectiv Acquisition allowing these employees the ability to commence receiving retirement benefits early without reducing their overall pension benefits. Our net periodic benefit cost is included in plant operating expense on our Consolidated Statements of Operations. As of December 31, 2011 and 2010, the total amount recognized in AOCI for actuarial losses related to pension obligation was approximately $3 million and nil, respectively.

In making our estimates of our pension obligation and related costs, we utilize discount rates, rates of compensation increases and rates of return on our assets that we believe are reasonable. Due to relatively small size of our pension liability (which is not considered material), significant changes in these assumptions would not have a material effect on our pension liability. During 2011 and 2010, we made contributions of approximately $3 million and $8 million, respectively, and estimated contributions to the pension plan are expected to be approximately $2 million in 2012. Estimated future benefit payments to participants in each of the next five years are expected to be less than $1 million in each year.

14. Capital Structure

Common Stock

Pursuant to our Plan of Reorganization, all shares of our common stock outstanding prior to the Effective Date were canceled and the issuance of 485 million new shares of reorganized Calpine Corporation common stock was authorized to resolve allowed unsecured claims. A portion of the 485 million authorized shares was immediately distributed, and the remainder was reserved for distribution to holders of certain disputed claims that, although allowed as of the Effective Date, were unresolved. In June 2011, we settled the largest remaining claim outstanding and began the process of distributing the balance of the reserved shares, which was completed during the third quarter of 2011, pursuant to our Plan of Reorganization.

Our authorized common stock consists of 1.4 billion shares of Calpine Corporation common stock. Common stock issued as of December 31, 2011 and 2010, was 490,468,815 shares and 444,883,356 shares, respectively, at a par value of $0.001 per share. Common stock outstanding as of December 31, 2011 and 2010, was 481,743,738 shares and 444,435,198 shares, respectively. The table below summarizes our common stock activity for the years ended December 31, 2011, 2010 and 2009.

	Shares Issued	Shares Held in Treasury	Shares Held in Reserve	Inter-Creditor Disputes	Total
Balance, December 31, 2008	429,025,057	(65,032)	48,162,203	9,752,261	486,874,489
Resolution of claims/inter-creditor disputes	13,167,420	—	(3,415,159)	(9,752,261)	—
Shares issued under Calpine Equity Incentive Plans	1,133,350	(262,540)	—	—	870,810
Balance, December 31, 2009	443,325,827	(327,572)	44,747,044	—	487,745,299
Resolution of claims	488,612	—	(488,612)	—	—
Shares issued under Calpine Equity Incentive Plans	1,068,917	(120,586)	—	—	948,331
Balance, December 31, 2010	444,883,356	(448,158)	44,258,432	—	488,693,630
Resolution of claims	44,258,432	—	(44,258,432)	—	—
Shares issued under Calpine Equity Incentive Plans	1,327,027	(139,846)	—	—	1,187,181
Share repurchase program	—	(8,137,073)	—	—	(8,137,073)
Balance, December 31, 2011	490,468,815	(8,725,077)	—	—	481,743,738

Treasury Stock

As of December 31, 2011 and 2010, we had treasury stock of 8,725,077 shares and 448,158 shares, respectively, with a cost of $125 million and $5 million, respectively. On August 23, 2011, we announced that our Board of Directors had authorized the repurchase of up to $300 million in shares of our common stock. The announced share repurchase program did not specify an expiration date. The repurchases may be commenced or suspended from time to time without prior notice. Through the filing of this Report, a total of 8,524,576 shares of our outstanding common stock have been repurchased under this program for approximately $124 million at an average price paid of $14.60 per share. Our treasury stock also consists of our common stock withheld to satisfy federal, state and local income tax withholding requirements for vested employee restricted stock awards. All treasury stock is held at cost.

15. Commitments and Contingencies

Long-Term Service Agreements

As of December 31, 2011, the total estimated commitments for LTSAs associated with turbines installed or in storage were approximately $70 million. These commitments are payable over the terms of the respective agreements, which range from 1 to 7 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.

Power Plant, Land and Other Operating Leases

We have entered into certain long-term operating leases for power plants, extending through 2020, 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. We have also entered into various land and other operating leases for ground facilities and operations, which extend through 2069. Future minimum lease payments under these leases are as follows (in millions):

	Initial Year	2012	2013	2014	2015	2016	Thereafter	Total
Land and other operating leases	various	$ 12	$ 11	$ 11	$ 14	$ 14	$ 431	$ 493
Power plant operating leases:								
Greenleaf	1998	$ 7	$ 7	$ 3	$ —	$ —	$ —	$ 17
KIAC	2000	24	24	24	23	22	74	191
Total power plant leases		$ 31	$ 31	$ 27	$ 23	$ 22	$ 74	$ 208
Total leases		$ 43	$ 42	$ 38	$ 37	$ 36	$ 505	$ 701

During the years ended December 31, 2011, 2010 and 2009, rent expense for power plant and land and other operating leases amounted to $53 million, $60 million and $60 million, respectively.

Production Royalties and Leases

We are obligated 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 consumer price index 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 geothermal power plants for the years ended December 31, 2011, 2010 and 2009, were $22 million, $25 million and $22 million, respectively.

Office and Equipment Leases

We lease our corporate and regional offices, as well as some of our office equipment, under noncancellable operating leases extending through 2020. Future minimum lease payments under these leases are as follows (in millions):

2012	$ 13
2013	12
2014	10
2015	10
2016	9
Thereafter	32
Total	$ 86

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, 2011, 2010 and 2009, rent expense for noncancellable operating leases was $13 million, $12 million and $12 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 power plants. The majority of our purchases are made in the spot market or under index-priced contracts. At December 31, 2011, we had future commitments of approximately $4.6 billion for natural gas purchases under contracts with terms from 1 to 15 years, and one contract with a term of 30 years.

Guarantees and Indemnifications

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 in the ordinary course of such subsidiaries' respective business. Such arrangements include guarantees, standby letters of credit and surety bonds for power and natural gas purchase and sale arrangements and contracts associated with the development, construction, operation and maintenance of our fleet of power plants. 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.

At December 31, 2011, 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	2012	2013	2014	2015	2016	Thereafter	Total
Guarantee of subsidiary debt[1]	$ 76	$ 73	$ 272	$ 36	$ 36	$ 236	$ 729
Standby letters of credit[2][4]	669	45	—	—	—	49	763
Surety bonds[3][4][5]	—	—	—	—	—	4	4
Guarantee of subsidiary operating lease payments[4]	7	7	3	—	—	—	17
Total	$ 752	$ 125	$ 275	$ 36	$ 36	$ 289	$ 1,513

(1) Represents Calpine Corporation guarantees of certain project debt, power plant capital leases and related interest. All guaranteed capital leases are recorded on our Consolidated Balance Sheets.

(2) The standby letters of credit disclosed above represent those disclosed in Note 6.

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

(4) These are contingent off balance sheet obligations.

(5) As of December 31, 2011, $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 issued 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.

Commercial Agreements — In connection with the purchase and sale of power, natural gas and emission allowances to and from third parties with respect to the operation of our power plants, we may be required to guarantee a portion of the obligations of certain of our subsidiaries. These guarantees may include future payment obligations as well as operational performance guarantees and effectively guarantee our future performance under certain agreements.

Purchase and Sale Agreements — 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.

Other — Additionally, we and our subsidiaries from time to time assume other guarantee and indemnification obligations in conjunction with other transactions such as parts supply agreements, construction agreements and equipment lease agreements. These guarantee and indemnification obligations may include future payment obligations and effectively guarantee our future performance under certain agreements.

Our potential exposure under guarantee and indemnification obligations can range from a specified amount to an unlimited dollar amount, depending on the nature of the claim and the particular transaction. Our total maximum exposure under our guarantee and indemnification obligations is not estimable due to uncertainty as to whether claims will be made or how any potential claim will be resolved. As of December 31, 2011, there are no outstanding claims related to our guarantee and indemnification obligations and we do not anticipate that we will be required to make any material payments under our guarantee and indemnification obligations.

Litigation

We are party to various litigation matters, including regulatory and administrative proceedings arising out of the normal course of business. On a quarterly basis, we review our litigation activities and determine if an unfavorable outcome to us is considered "remote," "reasonably possible" or "probable" as defined by U.S. GAAP. Where we determine an unfavorable outcome is probable and is reasonably estimable, we accrue for potential litigation losses. The liability we may ultimately incur with respect to such litigation matters, in the event of a negative outcome, may be in excess of amounts currently accrued, if any; however, we do not expect that the reasonably possible outcome of these litigation matters would, individually or in the aggregate, have a material adverse effect to our financial position, results of operations or cash flows. Where we determine an unfavorable outcome is not probable or reasonably estimable, we do not accrue for any potential litigation loss. The ultimate outcome of these litigation matters cannot presently be determined, nor can the liability that could potentially result from a negative outcome be reasonably estimated. As a result, we give no assurance that such litigation matters would, individually or in the aggregate, not have a material adverse effect to our financial position, results of operations or cash flows. Further, 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.

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

On November 5, 2006, the U.S. Court of Appeals for the Ninth Circuit issued a decision granting the plaintiffs relief by holding that the BLM had not complied with the National Environmental Policy Act, and other procedural requirements and, therefore, held that the lease extensions were invalid. On August 2, 2010, the Ninth Circuit issued a decision upholding the validity of the leases and confirming the court's order to remand the lease extension decisions for further evaluation, including preparation of an environmental impact statement. On November 4, 2010, the United States District Court for the Eastern District of California entered an order remanding the matter to federal agencies to implement the Court's order. We consider this litigation closed and anticipate it will take the federal agencies several years to implement the Court's order to conduct additional analysis. Accordingly, we plan to remove this matter from future filings until, and if and when, future action is taken by the Pit River Tribe.

In addition, in May 2004, the Pit River Tribe and other interested parties filed two separate suits in the District Court seeking to enjoin exploration, construction, and development of the Telephone Flat leases and proposed project at Glass Mountain. These two cases have remained mostly inactive. However, with the favorable resolution of the litigation over validity of the two Fourmile Hill leases, we anticipate the Pit River Tribe and other interested parties may seek to reactivate the two additional suits, and we are in communication with the U.S. Department of Justice regarding how to proceed.

Environmental Matters

We are subject to complex and stringent environmental laws and regulations related to the operation of our power plants. On occasion, we may incur environmental fees, penalties and fines associated with the normal operation of our power plants. We do not, however, have environmental violations or other matters that would have a material impact on our financial condition, results of operations or cash flows or that would significantly change our operations. A summary of our larger environmental matters are as follows:

Environmental Remediation of Certain Assets Acquired from Conectiv — As part of the Conectiv Acquisition on July 1, 2010, we assumed environmental remediation liabilities related to certain of the assets located in New Jersey that are subject to the ISRA. We have accrued or paid $10 million related to these liabilities at December 31, 2011. Pursuant to the Conectiv Purchase Agreement, PHI is responsible for any amounts that exceed $10 million associated with New Jersey environmental remediation liabilities. Our accrual is included in our allocation of the Conectiv Acquisition purchase price. See Note 3 for disclosures related to our Conectiv Acquisition.

Other Contingencies

Distribution of Calpine Common Stock under our Plan of Reorganization — On June 2, 2011, we reached a settlement with holders of the CalGen Third Lien Debt which was funded from the sale of a portion of the shares held in reserve. The U.S.

Bankruptcy Court approved the settlement with the CalGen Third Lien Debt claimants on June 16, 2011 and the settlement agreements were fully implemented in August 2011. As of December 31, 2011, all 485 million shares authorized in the confirmed Plan of Reorganization have been distributed to creditors in accordance with the terms of the Plan of Reorganization. The distribution of the remaining shares did not represent the issuance of new or additional shares and had no impact on our financial position, results of operations or cash flows. During the fourth quarter of 2011, the U.S. Bankruptcy Court issued an order dismissing the Chapter 11 cases that remained open against the U.S. Debtors; thus, all matters related to our voluntary petitions for relief under Chapter 11 of the Bankruptcy Code filed in 2005 and 2006 are resolved and closed.

16. Segment and Significant Customer Information

We assess our business on a regional basis due to the impact on our financial performance of the differing characteristics of these regions, particularly with respect to competition, regulation and other factors impacting supply and demand. At December 31, 2011, our reportable segments were West (including geothermal), Texas, North (including Canada and the assets purchased in the Conectiv Acquisition) and Southeast. We continue to evaluate the optimal manner in which we assess our performance including our segments and future changes may result.

Commodity Margin includes our power and steam revenues, sales of purchased power and physical natural gas, capacity revenue, REC revenue, sales of surplus emission allowances, transmission revenue and expenses, fuel and purchased energy expense, fuel transportation expense, RGGI compliance and other environmental costs, and cash settlements from our marketing, hedging and optimization activities including natural gas transactions hedging future power sales that are included in mark-to-market activity, but excludes the unrealized portion of our mark-to-market activity and other revenues. Commodity Margin is a key operational measure reviewed by our chief operating decision maker to assess the performance of our segments. The tables below show our financial data for our segments for the periods indicated (in millions).

	Year Ended December 31, 2011					
	West	Texas	North	Southeast	Consolidation and Elimination	Total
Revenues from external customers	$ 2,372	$ 2,306	$ 1,336	$ 786	$ —	$ 6,800
Intersegment revenues	12	23	7	135	(177)	—
Total operating revenues	$ 2,384	$ 2,329	$ 1,343	$ 921	$ (177)	$ 6,800
Commodity Margin	$ 1,061	$ 469	$ 704	$ 240	$ —	$ 2,474
Add: Mark-to-market commodity activity, net and other[1][2]	113	(102)	(13)	1	(32)	(33)
Less:						
Plant operating expense	380	235	177	141	(29)	904
Depreciation and amortization expense	192	135	138	90	(5)	550
Sales, general and other administrative expense	43	43	24	22	(1)	131
Other operating expenses[3]	41	3	30	5	(2)	77
(Income) from unconsolidated investments in power plants	—	—	(21)	—	—	(21)
Income (loss) from operations	518	(49)	343	(17)	5	800
Interest expense, net of interest income						751
Loss on interest rate derivatives						145
Debt extinguishment costs and other (income) expense, net						115
Loss before income taxes and discontinued operations						$ (211)

	Year Ended December 31, 2010					
	West	Texas	North	Southeast	Consolidation and Elimination	Total
Revenues from external customers	$ 2,525	$ 2,162	$ 978	$ 880	$ —	$ 6,545
Intersegment revenues	12	22	6	138	(178)	—
Total operating revenues	$ 2,537	$ 2,184	$ 984	$ 1,018	$ (178)	$ 6,545
Commodity Margin	$ 1,080	$ 504	$ 535	$ 272	$ —	$ 2,391
Add: Mark-to-market commodity activity, net and other[1]	69	89	21	22	(30)	171
Less:						
Plant operating expense	351	285	138	123	(29)	868
Depreciation and amortization expense	207	150	111	109	(7)	570
Sales, general and other administrative expense	55	38	45	12	1	151
Other operating expenses[3]	59	2	28	4	(2)	91
Impairment losses	97	—	—	19	—	116
(Gain) on sale of assets, net	—	(119)	—	—	—	(119)
(Income) from unconsolidated investments in power plants	—	—	(16)	—	—	(16)
Income from operations	380	237	250	27	7	901
Interest expense, net of interest income						802
Loss on interest rate derivatives						223
Debt extinguishment costs and other (income) expense, net						106
Loss before income taxes and discontinued operations						$ (230)

	Year Ended December 31, 2009					
	West	Texas	North	Southeast	Consolidation and Elimination	Total
Revenues from external customers	$ 3,311	$ 1,816	$ 558	$ 778	$ —	$ 6,463
Intersegment revenues	28	63	16	97	(204)	—
Total operating revenues	$ 3,339	$ 1,879	$ 574	$ 875	$ (204)	$ 6,463
Commodity Margin	$ 1,245	$ 644	$ 268	$ 304	$ —	$ 2,461
Add: Mark-to-market commodity activity, net and other[1]	143	(40)	46	(5)	(44)	100
Less:						
Plant operating expense	408	232	91	134	3	868
Depreciation and amortization expense	188	129	67	80	(8)	456
Sales, general and other administrative expense	66	63	18	27	—	174
Other operating expenses[3]	73	14	30	11	(32)	96
Impairment losses	4	—	—	—	—	4
(Income) from unconsolidated investments in power plants	(32)	—	(18)	—	—	(50)
Income from operations	681	166	126	47	(7)	1,013
Interest expense, net of interest income						799
Debt extinguishment costs and other (income) expense, net						89
Income before income taxes and discontinued operations						$ 125

(1) Mark-to-market commodity activity represents the unrealized portion of our mark-to-market activity, net, included in operating revenues and fuel and purchased energy expense on our Consolidated Statements of Operations for the years ended December 31, 2011, 2010 and 2009, as well as a non-cash gain from amortization of prepaid power sales agreements for the year ended December 31, 2009.

(2) Includes $12 million of lease levelization and $8 million of contract amortization for the year ended December 31, 2011 related to contracts that became effective in 2011.

(3) Excludes $10 million, $9 million and $5 million of RGGI compliance and other environmental costs for the years ended December 31, 2011, 2010 and 2009, respectively, which are components of Commodity Margin.

Significant Customer

For the year ended December 31, 2011, we had one significant customer, PJM Settlement, Inc., that accounted for more than 10% of our annual consolidated revenues. Our revenues of $742 million from PJM Settlement, Inc. for the year ended December 31, 2011, were attributed to our North segment. Our receivables from PJM Settlement, Inc. were $28 million as of December 31, 2011. We did not have a customer that accounted for more than 10% of our annual consolidated revenues for the years ended December 31, 2010 or 2009.

17. 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, energy commodity market prices 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)			
2011				
Operating revenues	$ 1,459	$ 2,209	$ 1,633	$ 1,499
Income from operations	196	403	183	18
Income (loss) before discontinued operations attributable to Calpine	$ (13)	$ 190	$ (70)	$ (297)
Discontinued operations, net of tax expense, attributable to Calpine	—	—	—	—
Net income (loss) attributable to Calpine	$ (13)	$ 190	$ (70)	$ (297)
Basic earnings (loss) per common share:				
Income (loss) before discontinued operations attributable to Calpine	$ (0.03)	$ 0.39	$ (0.14)	$ (0.61)
Discontinued operations, net of tax expense, attributable to Calpine	—	—	—	—
Net income (loss) attributable to Calpine	$ (0.03)	$ 0.39	$ (0.14)	$ (0.61)
Diluted earnings (loss) per common share:				
Income (loss) before discontinued operations attributable to Calpine	$ (0.03)	$ 0.39	$ (0.14)	$ (0.61)
Discontinued operations, net of tax expense, attributable to Calpine	—	—	—	—
Net income (loss) attributable to Calpine	$ (0.03)	$ 0.39	$ (0.14)	$ (0.61)
2010				
Operating revenues	$ 1,471	$ 2,130	$ 1,430	$ 1,514
Income from operations	89	554	108	150
Income (loss) before discontinued operations attributable to Calpine	$ (186)	$ 198	$ (119)	$ (55)
Discontinued operations, net of tax expense, attributable to Calpine	162	19	4	8
Net income (loss) attributable to Calpine	$ (24)	$ 217	$ (115)	$ (47)
Basic earnings (loss) per common share:				
Income (loss) before discontinued operations attributable to Calpine	$ (0.38)	$ 0.41	$ (0.25)	$ (0.11)
Discontinued operations, net of tax expense, attributable to Calpine	0.33	0.04	0.01	0.01
Net income (loss) attributable to Calpine	$ (0.05)	$ 0.45	$ (0.24)	$ (0.10)
Diluted earnings (loss) per common share:				
Income (loss) before discontinued operations attributable to Calpine	$ (0.38)	$ 0.41	$ (0.25)	$ (0.11)
Discontinued operations, net of tax expense, attributable to Calpine	0.33	0.04	0.01	0.01
Net income (loss) attributable to Calpine	$ (0.05)	$ 0.45	$ (0.24)	$ (0.10)

CALPINE CORPORATION AND SUBSIDIARIES

SCHEDULE II VALUATION AND QUALIFYING ACCOUNTS

Description	Balance at Beginning of Year	Charged to Expense	Charged to Other Accounts	Deductions[1]	Balance at End of Year
			(in millions)		
Year ended December 31, 2011					
Allowance for doubtful accounts	$ 2	$ 7	$ 4	$ —	$ 13
Deferred tax asset valuation allowance	2,386	(50)	—	—	2,336
Year ended December 31, 2010					
Allowance for doubtful accounts	$ 14	$ (12)	$ —	$ —	$ 2
Deferred tax asset valuation allowance	2,572	(186)	—	—	2,386
Year ended December 31, 2009					
Allowance for doubtful accounts	$ 42	$ 2	$ —	$ (30)	$ 14
Deferred tax asset valuation allowance	2,685	(113)	—	—	2,572

(1) Represents write-offs of accounts considered to be uncollectible and previously reserved.

Board of Directors

J. Stuart Ryan [N]
Chairman of the Board
Chief Executive Officer, Aggregates USA and
Founding Owner and President, Rydout LLC

Frank Cassidy [C]
Retired President and Chief Operating Officer
PSEG Power LLC

Jack A. Fusco
President and Chief Executive Officer, Calpine Corp.

Robert C. Hinckley [A][N]
Chairman and Managing Director, MCL Intellectual
Property LLC

David C. Merritt [A]
President, BC Partners, Inc.

W. Benjamin Moreland [A]
President and Chief Executive Officer
Crown Castle International Corp.

Robert A. Mosbacher, Jr. [C][N]
Chairman, Mosbacher Energy Company

William E. Oberndorf [C]
Founding Partner, SPO Advisory Corp.

Denise M. O'Leary [C][N]
Private Venture Capital Investor

[A] Audit Committee
[C] Compensation Committee
[N] Nominating and Governance Committee

Executive Management

Jack A. Fusco
President and Chief Executive Officer

John B. (Thad) Hill
Executive Vice President and Chief Operating Officer

Gary M. Germeroth
Executive Vice President and Chief Risk Officer

W. Thaddeus Miller
Executive Vice President, Chief Legal Officer and
Corporate Secretary

Zamir Rauf
Executive Vice President and Chief Financial Officer

General Information

Corporate Headquarters
Calpine Corporation
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
Pricewaterhouse Coopers LLP
Houston, Texas

Transfer Agent
Computershare, Inc.
P.O. Box 43078
Providence, RI 02940-3078
877-745-9351

Stock Information
Calpine Corporation's common stock is listed on the NYSE under the symbol CPN.

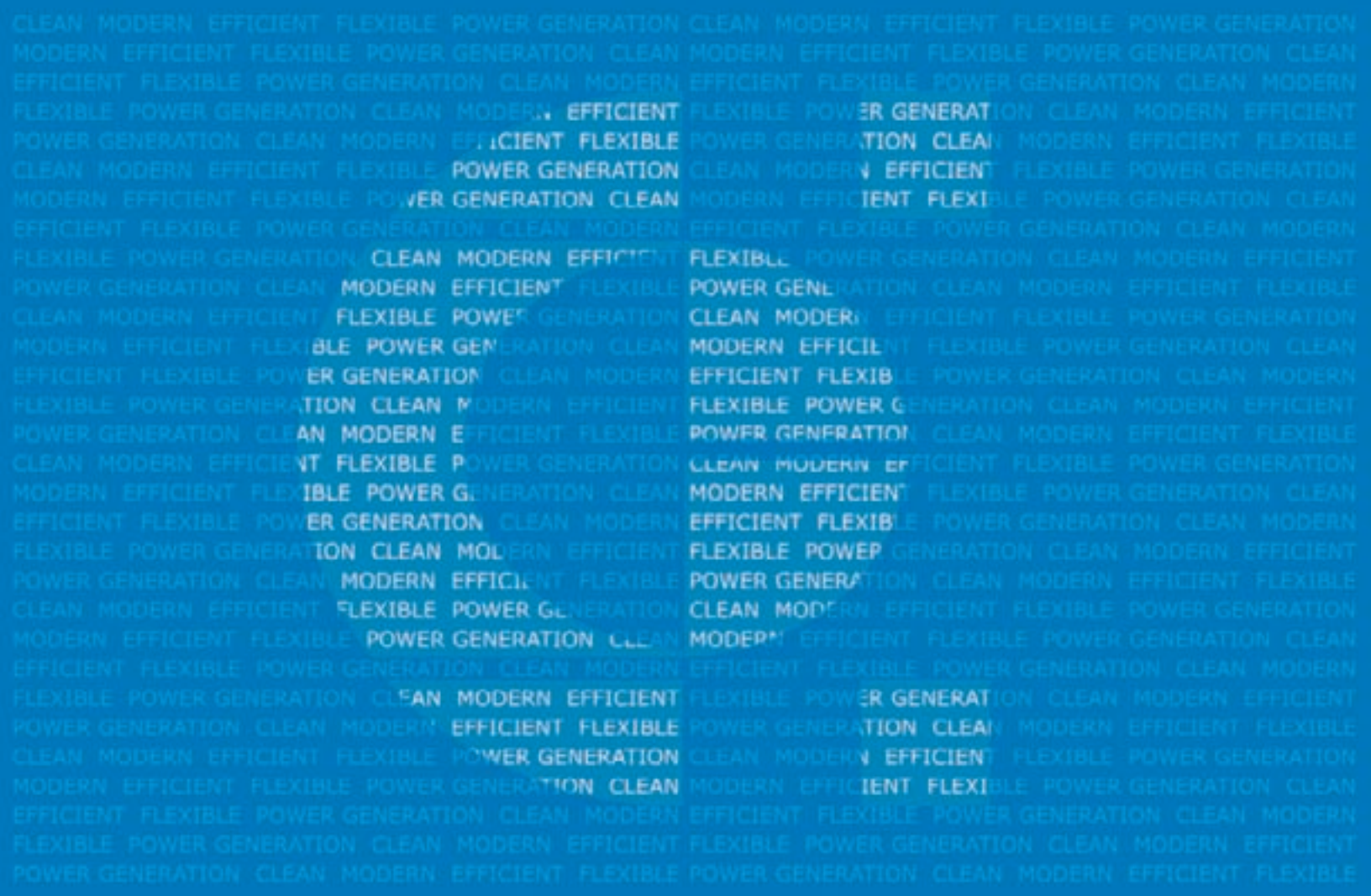
Form 10-K
The Company's Annual Report on Form 10-K for the year ended December 31, 2011, as filed with the Securities and Exchange Commission, is included in this report. Additional copies may be obtained without charge by writing:

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 Tuesday, May 15, 2012, at 8 a.m. Central Time at our corporate offices located at 717 Texas Ave., 10th floor, Houston, TX 77002. All shareholders are cordially invited to attend.

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, 2011, 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.

DESIGN: ARTISAN FIELD INC., HOUSTON



Calpine Corporation
717 Texas Avenue, Suite 1000
Houston, Texas 77002
(713) 830-2000

WWW.CALPINE.COM