10-Q 1 cpn_10qx06302015.htm CALPINE 10-Q FOR QUARTERLY PERIOD ENDED JUNE 30, 2015

UNITED STATES
SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

Form 10-Q

(Mark One)

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

For the quarterly period ended June 30, 2015

Or

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

For the transition period from to
Commission File No. 001-12079

Calpine Corporation

(A Delaware Corporation)
I.R.S. Employer Identification No. 77-0212977

717 Texas Avenue, Suite 1000, Houston, Texas 77002
Telephone: (713) 830-2000

Not Applicable
(Former Address)

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. 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 whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See definitions of “large accelerated filer,” “accelerated filer,” and “smaller reporting company” in Rule 12b-2 of the Exchange Act. (Check one):

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

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

Indicate the number of shares outstanding of each of the registrant’s classes of common stock, as of the latest practicable date: 360,092,812 shares of common stock, par value $0.001, were outstanding as of July 28, 2015.

CALPINE CORPORATION AND SUBSIDIARIES

REPORT ON FORM 10-Q
For the Quarter Ended June 30, 2015

INDEX

DEFINITIONS

As used in this report for the quarter ended June 30, 2015 (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
2014 Form 10-K	Calpine Corporation's Annual Report on Form 10-K for the year ended December 31, 2014, filed with the SEC on February 13, 2015
2018 First Lien Term Loans	Collectively, the $1.3 billion first lien senior secured term loan dated March 9, 2011 and the $360 million first lien senior secured term loan dated June 17, 2011
2019 First Lien Term Loan	The $835 million first lien senior secured term loan, dated October 9, 2012, among Calpine Corporation, as borrower, the lenders party hereto, Morgan Stanley Senior Funding, Inc., as administrative agent and Goldman Sachs Credit Partners L.P., as collateral agent
2020 First Lien Term Loan	The $390 million first lien senior secured term loan, dated October 23, 2013, among Calpine Corporation, as borrower, the lenders party hereto, Citibank, N.A., as administrative agent and Goldman Sachs Credit Partners L.P., as collateral agent
2022 First Lien Notes	The $750 million aggregate principal amount of 6.0% senior secured notes due 2022, issued October 31, 2013
2022 First Lien Term Loan	The $1.6 billion first lien senior secured term loan, dated May 28, 2015, among Calpine Corporation, as borrower, the lenders party hereto, Morgan Stanley Senior Funding, Inc., as administrative agent and Goldman Sachs Credit Partners L.P., as collateral agent
2023 First Lien Notes	The $1.2 billion aggregate principal amount of 7.875% senior secured notes due 2023, issued January 14, 2011
2023 Senior Unsecured Notes	The $1.25 billion aggregate principal amount of 5.375% senior unsecured notes due 2023, issued July 22, 2014
2024 First Lien Notes	The $490 million aggregate principal amount of 5.875% senior secured notes due 2024, issued October 31, 2013
2024 Senior Unsecured Notes	The $650 million aggregate principal amount of 5.5% senior unsecured notes due 2024, issued February 3, 2015
2025 Senior Unsecured Notes	The $1.55 billion aggregate principal amount of 5.75% senior unsecured notes due 2025, issued July 22, 2014
Adjusted EBITDA	EBITDA as adjusted for the effects of (a) impairment charges, (b) major maintenance expense, (c) operating lease expense, (d) gains or losses on commodity derivative mark-to-market activity, (e) adjustments to reflect only the Adjusted EBITDA from our unconsolidated investments, (f) adjustments to exclude the Adjusted EBITDA related to the noncontrolling interest, (g) stock-based compensation expense, (h) gains or losses on sales, dispositions or retirements of assets, (i) non-cash gains and losses from foreign currency translations, (j) gains or losses on the repurchase, modification or extinguishment of debt, (k) non-cash GAAP-related adjustments to levelize revenues from tolling agreements 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 power generation as a percent of total potential power 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

ABBREVIATION	DEFINITION
Btu	British thermal unit(s), a measure of heat content
CAISO	California Independent System Operator
Calpine Equity Incentive Plans	Collectively, the Director Plan and the Equity Plan, which provide for grants of equity awards to Calpine non-union 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
CCFC	Calpine Construction Finance Company, L.P., an indirect, wholly-owned subsidiary of Calpine
CCFC Term Loans	Collectively, the $900 million first lien senior secured term loan and the $300 million first lien senior secured term loan entered into on May 3, 2013, and the $425 million first lien senior secured term loan entered into on February 26, 2014, between CCFC, as borrower, and Goldman Sachs Lending Partners, LLC, as administrative agent and as collateral agent, and the lenders party thereto
CDHI	Calpine Development Holdings, Inc., an indirect, wholly-owned subsidiary of Calpine
CFTC	Commodity Futures Trading Commission
Champion Energy	Champion Energy Marketing, LLC, which owns a retail electric provider that serves residential, governmental, commercial and industrial customers in deregulated electricity markets in Texas, Illinois, Pennsylvania, Ohio, New Jersey, Maryland, Massachusetts and New York
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, environmental compliance expense and realized settlements from our marketing, hedging and optimization activities including natural gas transactions hedging future power sales, but excludes 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, environmental compliance expense, and realized settlements from our marketing, hedging, optimization and trading activities, but excludes 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 realized settlements from our marketing, hedging, optimization and trading activities, but excludes our mark-to-market activity
Company	Calpine Corporation, a Delaware corporation, and its subsidiaries

ABBREVIATION	DEFINITION
Corporate Revolving Facility	The $1.5 billion aggregate amount revolving credit facility credit agreement, dated as of December 10, 2010, as amended on June 27, 2013 and July 30, 2014, 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
Director Plan	The Amended and Restated Calpine Corporation 2008 Director Incentive Plan
EBITDA	Net income (loss) attributable to Calpine before net (income) loss attributable to the noncontrolling interest, interest, taxes, depreciation and amortization
EPA	U.S. Environmental Protection Agency
Equity Plan	The Amended and Restated Calpine Corporation 2008 Equity Incentive Plan
ERCOT	Electric Reliability Council of Texas
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 Notes	Collectively, the 2022 First Lien Notes, the 2023 First Lien Notes and the 2024 First Lien Notes
First Lien Term Loans	Collectively, the 2018 First Lien Term Loans, the 2019 First Lien Term Loan, the 2020 First Lien Term Loan and the 2022 First Lien Term Loan
GE	General Electric International, Inc.
Geysers Assets	Our geothermal power plant assets, including our steam extraction and gathering assets, located in northern California consisting of 14 operating power plants
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)
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
IRS	U.S. Internal Revenue Service
ISO(s)	Independent System Operator(s)
ISO-NE	ISO New England Inc., an independent nonprofit RTO serving states in the New England area, including Connecticut, Maine, Massachusetts, New Hampshire, Rhode Island and Vermont
KWh	Kilowatt hour(s), a measure of power produced, purchased or sold
LIBOR	London Inter-Bank Offered Rate

Market Heat Rate(s)	The regional power price divided by the corresponding regional natural gas price
MMBtu	Million Btu
MW	Megawatt(s), a measure of plant capacity

ABBREVIATION	DEFINITION
MWh	Megawatt hour(s), a measure of power produced, purchased or sold
NOL(s)	Net operating loss(es)
NYMEX	New York Mercantile Exchange
OCI	Other Comprehensive Income
OTC	Over-the-Counter
PJM	PJM Interconnection is a RTO that coordinates the movement of wholesale electricity in all or parts of Delaware, Illinois, Indiana, Kentucky, Maryland, Michigan, New Jersey, North Carolina, Ohio, Pennsylvania, Tennessee, Virginia, West Virginia and the District of Columbia
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
PUCT	Public Utility Commission of Texas
REC(s)	Renewable energy credit(s)
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
RPS	Renewable Portfolio Standard
RTO(s)	Regional Transmission Organization(s)
SEC	U.S. Securities and Exchange Commission
Securities Act	U.S. Securities Act of 1933, as amended
Senior Unsecured Notes	Collectively, the 2023 Senior Unsecured Notes, the 2024 Senior Unsecured Notes and the 2025 Senior Unsecured Notes
Spark Spread(s)	The difference between the sales price of power per MWh and the cost of natural gas to produce it
Steam Adjusted Heat Rate	The adjusted Heat Rate for our natural gas-fired power plants, excluding peakers, calculated by dividing (a) the fuel consumed in Btu reduced by the net equivalent Btu in steam exported to a third party by (b) the KWh generated. Steam Adjusted Heat Rate is a measure of fuel efficiency, so the lower our Steam Adjusted Heat Rate, the lower our cost of generation
TSR	Total shareholder return
U.S. GAAP	Generally accepted accounting principles in the U.S.
VAR	Value-at-risk

VIE(s)	Variable interest entity(ies)
Whitby	Whitby Cogeneration Limited Partnership, a 50% partnership interest between certain of our subsidiaries and a third party, which operates Whitby, a 50 MW natural gas-fired, simple-cycle cogeneration power plant located in Ontario, Canada

Forward-Looking Statements

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, seasonality of demand, 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 and extent to which we hedge risks;
- Laws, regulations and market rules in the markets in which we participate and our ability to effectively respond to changes in laws, regulations or market rules or the interpretation thereof including those related to the environment, derivative transactions and market design in the regions in which we operate;
- Our ability to manage our liquidity needs, access the capital markets when necessary and comply with covenants under our Senior Unsecured Notes, First Lien Notes, First Lien Term Loans, Corporate Revolving Facility, CCFC Term Loans and other existing financing obligations;
- 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 water 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;
- Structural changes in the supply and demand of power, resulting from the development of new fuels or technologies and demand-side management tools (such as distributed generation, power storage and other technologies);
- 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, droughts 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 that may arise from noncompliance with market rules promulgated by the SEC, CFTC, FERC and other regulatory bodies; and
- Other risks identified in this Report, in our 2014 Form 10-K and in other reports filed by us with the SEC.

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 to 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 — FINANCIAL INFORMATION

Item 1. ***Financial Statements***

CALPINE CORPORATION AND SUBSIDIARIES
CONSOLIDATED CONDENSED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in millions, except share and per share amounts)			
Operating revenues:				
Commodity revenue	$ 1,407	$ 1,766	$ 3,045	$ 3,814
Mark-to-market gain	31	169	34	83
Other revenue	4	4	9	7
Operating revenues	1,442	1,939	3,088	3,904
Operating expenses:				
Fuel and purchased energy expense:				
Commodity expense	734	1,106	1,811	2,476
Mark-to-market (gain) loss	32	28	(35)	15
Fuel and purchased energy expense	766	1,134	1,776	2,491
Plant operating expense	272	274	532	539
Depreciation and amortization expense	160	147	318	300
Sales, general and other administrative expense	30	38	67	71
Other operating expenses	20	21	40	43
Total operating expenses	1,248	1,614	2,733	3,444
(Income) from unconsolidated investments in power plants	(7)	(4)	(12)	(13)
Income from operations	201	329	367	473
Interest expense	158	169	312	335
Interest (income)	(1)	(2)	(2)	(3)
Debt modification and extinguishment costs	13	—	32	1
Other (income) expense, net	5	6	7	16
Income before income taxes	26	156	18	124
Income tax expense (benefit)	5	15	4	(4)
Net income	21	141	14	128
Net income attributable to the noncontrolling interest	(2)	(2)	(5)	(6)
Net income attributable to Calpine	$ 19	$ 139	$ 9	$ 122
Basic earnings per common share attributable to Calpine:				
Weighted average shares of common stock outstanding (in thousands)	366,975	416,507	369,938	418,296
Net income per common share attributable to Calpine — basic	$ 0.05	$ 0.33	$ 0.02	$ 0.29
Diluted earnings per common share attributable to Calpine:				
Weighted average shares of common stock outstanding (in thousands)	369,946	421,348	373,404	422,697
Net income per common share attributable to Calpine — diluted	$ 0.05	$ 0.33	$ 0.02	$ 0.29

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

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED CONDENSED STATEMENTS OF COMPREHENSIVE INCOME
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
	(in millions)			
Net income	$ 21	$ 141	$ 14	$ 128
Cash flow hedging activities:				
Gain (loss) on cash flow hedges before reclassification adjustment for cash flow hedges realized in net income	2	(22)	(16)	(35)
Reclassification adjustment for loss on cash flow hedges realized in net income	12	13	24	26
Foreign currency translation gain (loss)	4	6	(8)	—
Income tax expense	—	—	—	—
Other comprehensive income (loss)	18	(3)	—	(9)
Comprehensive income	39	138	14	119
Comprehensive (income) attributable to the noncontrolling interest	(4)	(1)	(6)	(5)
Comprehensive income attributable to Calpine	$ 35	$ 137	$ 8	$ 114

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

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED CONDENSED BALANCE SHEETS
(Unaudited)

	June 30, 2015	December 31, 2014
	(in millions, except share and per share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents ($254 and $229 attributable to VIEs)	$ 422	$ 717
Accounts receivable, net of allowance of $3 and $4	595	648
Inventories	477	447
Margin deposits and other prepaid expense	152	148
Restricted cash, current ($93 and $106 attributable to VIEs)	162	195
Derivative assets, current	1,607	2,058
Other current assets	32	7
Total current assets	3,447	4,220
Property, plant and equipment, net ($4,260 and $4,342 attributable to VIEs)	13,147	13,190
Restricted cash, net of current portion ($47 and $48 attributable to VIEs)	48	49
Investments in power plants	87	95
Long-term derivative assets	637	439
Other assets ($172 and $164 attributable to VIEs)	391	385
Total assets	$ 17,757	$ 18,378
LIABILITIES & STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 443	$ 580
Accrued interest payable	133	165
Debt, current portion ($148 and $150 attributable to VIEs)	198	199
Derivative liabilities, current	1,407	1,782
Other current liabilities	355	473
Total current liabilities	2,536	3,199
Debt, net of current portion ($3,168 and $3,242 attributable to VIEs)	11,493	11,083
Long-term derivative liabilities	453	444
Other long-term liabilities	274	221
Total liabilities	14,756	14,947
Commitments and contingencies (see Note 11)		
Stockholders' equity:		
Preferred stock, $0.001 par value per share; authorized 100,000,000 shares, none issued and outstanding	—	—
Common stock, $0.001 par value per share; authorized 1,400,000,000 shares, 504,252,268 and 502,287,022 shares issued, respectively, and 361,150,393 and 381,921,264 shares outstanding, respectively	1	1
Treasury stock, at cost, 143,101,875 and 120,365,758 shares, respectively	(2,810)	(2,345)
Additional paid-in capital	12,463	12,440
Accumulated deficit	(6,531)	(6,540)
Accumulated other comprehensive loss	(179)	(178)
Total Calpine stockholders' equity	2,944	3,378

Noncontrolling interest		57		53
Total stockholders’ equity		3,001		3,431
Total liabilities and stockholders’ equity	$	17,757	$	18,378

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

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED CONDENSED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30,	
	2015	2014
	(in millions)	
Cash flows from operating activities:		
Net income	$ 14	$ 128
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation and amortization expense(1)	342	322
Deferred income taxes	3	(12)
Mark-to-market activity, net	(70)	(70)
(Income) from unconsolidated investments in power plants	(12)	(13)
Return on unconsolidated investments in power plants	13	13
Stock-based compensation expense	12	22
Other	2	2
Change in operating assets and liabilities:		
Accounts receivable	29	(212)
Derivative instruments, net	(36)	(109)
Other assets	(118)	(40)
Accounts payable and accrued expenses	(205)	378
Other liabilities	45	(60)
Net cash provided by operating activities	19	349
Cash flows from investing activities:		
Purchases of property, plant and equipment	(279)	(258)
Purchase of Guadalupe Energy Center	—	(656)
Decrease in restricted cash	34	14
Other	(1)	—
Net cash used in investing activities	(246)	(900)
Cash flows from financing activities:		
Borrowings under CCFC Term Loans and First Lien Term Loans	1,592	420
Repayment of CCFC Term Loans and First Lien Term Loans	(1,613)	(23)
Borrowings under Senior Unsecured Notes	650	—
Repurchase of First Lien Notes	(147)	—
Borrowings from project financing, notes payable and other	—	2
Repayments of project financing, notes payable and other	(85)	(55)
Financing costs	(17)	(10)
Stock repurchases	(454)	(297)
Proceeds from exercises of stock options	6	15
Net cash provided by (used in) financing activities	(68)	52
Net decrease in cash and cash equivalents	(295)	(499)
Cash and cash equivalents, beginning of period	717	941
Cash and cash equivalents, end of period	$ 422	$ 442

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

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED CONDENSED STATEMENTS OF CASH FLOWS — (CONTINUED)
(Unaudited)

	Six Months Ended June 30,	
	2015	2014
	(in millions)	
Cash paid during the period for:		
Interest, net of amounts capitalized	$ 322	$ 288
Income taxes	$ 17	$ 16
Supplemental disclosure of non-cash investing and financing activities:		
Change in capital expenditures included in accounts payable	$ (20)	$ 13
Additions to property, plant and equipment through capital lease	$ 9	$ —

(1) Includes depreciation and amortization included in fuel and purchased energy expense and interest expense on our Consolidated Condensed Statements of Operations.

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

NOTES TO CONSOLIDATED CONDENSED FINANCIAL STATEMENTS
June 30, 2015
(Unaudited)

1. Basis of Presentation and Summary of Significant Accounting Policies

We are a 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 (included in our West segment), Texas (included in our Texas segment) and the Northeast region (included in our East segment) 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 purchase primarily natural gas and some fuel oil as fuel for our power plants and engage in related natural gas transportation and storage transactions. We purchase electric transmission rights to deliver power to our customers. Additionally, consistent with our Risk Management Policy, we enter into natural gas, power and other physical and financial contracts to hedge certain business risks and optimize our portfolio of power plants.

Basis of Interim Presentation — The accompanying unaudited, interim Consolidated Condensed Financial Statements of Calpine Corporation, a Delaware corporation, and consolidated subsidiaries have been prepared pursuant to the rules and regulations of the SEC. In the opinion of management, the Consolidated Condensed Financial Statements include the normal, recurring adjustments necessary for a fair statement of the information required to be set forth therein. Certain information and note disclosures, normally included in financial statements prepared in accordance with U.S. GAAP, have been condensed or omitted from these statements pursuant to such rules and regulations and, accordingly, these financial statements should be read in conjunction with our audited Consolidated Financial Statements for the year ended December 31, 2014, included in our 2014 Form 10-K. The results for interim periods are not indicative of the results for the entire year primarily due to acquisitions and disposals of assets, seasonal fluctuations in our revenues, timing of major maintenance expense, variations resulting from the application of the method to calculate the provision for income tax for interim periods, volatility of commodity prices and mark-to-market gains and losses from commodity and interest rate derivative contracts.

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 Condensed Financial Statements. Actual results could differ from those estimates.

Reclassifications — We have reclassified certain prior year amounts for comparative purposes. These reclassifications did not have a material impact on our financial condition, results of operations or cash flows.

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.

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 are expected to 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 Condensed Balance Sheets and Statements of Cash Flows.

The table below represents the components of our restricted cash as of June 30, 2015 and December 31, 2014 (in millions):

	June 30, 2015			December 31, 2014		
	Current	Non-Current	Total	Current	Non-Current	Total
Debt service	$ 16	$ 25	$ 41	$ 10	$ 25	$ 35
Rent reserve	—	—	—	4	—	4
Construction/major maintenance	50	19	69	54	17	71
Security/project/insurance	93	4	97	127	5	132
Other	3	—	3	—	2	2
Total	$ 162	$ 48	$ 210	$ 195	$ 49	$ 244

Property, Plant and Equipment, Net — At June 30, 2015 and December 31, 2014, the components of property, plant and equipment are stated at cost less accumulated depreciation as follows (in millions):

	June 30, 2015	December 31, 2014	Depreciable Lives
Buildings, machinery and equipment	$ 16,422	$ 16,059	3 – 47 Years
Geothermal properties	1,320	1,294	13 – 58 Years
Other	208	203	3 – 47 Years
	17,950	17,556	
Less: Accumulated depreciation	5,236	4,984	
	12,714	12,572	
Land	121	120	
Construction in progress	312	498	
Property, plant and equipment, net	$ 13,147	$ 13,190	

Capitalized Interest — The total amount of interest capitalized was $4 million and $6 million for the three months ended June 30, 2015 and 2014, respectively, and $9 million and $12 million for the six months ended June 30, 2015 and 2014, respectively.

Treasury Stock — During the six months ended June 30, 2015, we repurchased a total of 22.1 million shares of our outstanding common stock for approximately $454 million at an average price of $20.50 per share. Additionally, we withheld shares with a value of $11 million to satisfy tax withholding obligations associated with the vesting of restricted stock awarded to employees and with net share employee stock option exercises under the Equity Plan.

New Accounting Standards and Disclosure Requirements

Revenue Recognition — In May 2014, the FASB issued Accounting Standards Update 2014-09, "Revenue from Contracts with Customers." The comprehensive new revenue recognition standard will supersede all existing revenue recognition guidance. The core principle of the standard is that a company should recognize revenue to depict the transfer of promised goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. The standard also requires expanded disclosures surrounding revenue recognition. The standard was effective for fiscal periods beginning after December 15, 2016, including interim periods within that reporting period and allows for either full retrospective or modified retrospective adoption with early adoption being prohibited. In July 2015, the FASB approved a proposal to defer the effective date of Accounting Standards Update 2014-09 for public entities by one year, which would result in the standard being effective for fiscal years and interim periods within those fiscal years beginning after December 15, 2017. The proposal would also permit entities to early adopt, but only as of the original effective date. We are currently assessing the future impact this standard may have on our financial condition, results of operations or cash flows.

Consolidation — In February 2015, the FASB issued Accounting Standards Update 2015-02, "Amendments to the Consolidation Analysis." This standard amends the consolidation model used in determining whether a reporting entity should consolidate the financial results of certain of its partially- and wholly-owned subsidiaries. All of our subsidiaries are subject to reevaluation under the revised consolidation model. Specifically, the amendments (i) modify the evaluation of whether limited partnerships and similar legal entities are voting interest entities or VIEs, (ii) eliminate the presumption that a general partner should consolidate the financial results of a limited partnership, (iii) affect the consolidation analysis of reporting entities that are involved with VIEs, particularly those that have fee arrangements and related party relationships and (iv) provide an exception for certain types of entities. This standard is effective for fiscal periods beginning after December 15, 2015, including interim periods within that reporting period and allows for either full retrospective or modified retrospective adoption with early adoption permitted. We do not anticipate a material impact on our financial condition, results of operations or cash flows as a result of adopting this standard.

Debt Issuance Costs — In April 2015, the FASB issued Accounting Standards Update 2015-03, "Simplifying the Presentation of Debt Issuance Costs." The standard requires debt issuance costs related to a recognized debt liability to be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, which is consistent with the presentation of debt discounts. The standard is effective for fiscal years beginning after December 15, 2015, including interim periods within that reporting period and requires retrospective adoption with early adoption permitted. We do not anticipate a material impact on our financial condition, results of operations or cash flows as a result of adopting this standard.

Cloud Computing Arrangements — In April 2015, the FASB issued Accounting Standards Update 2015-05, "Customer's Accounting for Fees Paid in a Cloud Computing Arrangement." This standard provides guidance regarding whether a cloud computing arrangement represents a software license or a service contract. The standard is effective for fiscal years beginning after December 15, 2015, including interim periods and allows for either prospective or retrospective adoption with early adoption permitted. We are currently assessing the future impact this standard may have on our financial condition, results of operations or cash flows.

Inventory — In July 2015, the FASB issued Accounting Standards Update 2015-11, "Simplifying the Measurement of Inventory." This standard changes the inventory valuation method from the lower of cost or market to the lower of cost or net realizable value for inventory valued under the first-in, first-out or average cost methods. The standard is effective for fiscal years beginning after December 15, 2016, including interim periods and requires prospective adoption with early adoption permitted. We do not anticipate a material impact on our financial condition, results of operations or cash flows as a result of adopting this standard.

2. Acquisitions

Acquisition of Champion Energy

On July 20, 2015, we announced that we have entered into an agreement, through our indirect, wholly-owned subsidiary Calpine Energy Services Holdco LLC, to purchase Champion Energy Marketing, LLC from Champion Energy Holdings, LLC, which owns a 75% interest, and EDF Trading North America, LLC, which owns a 25% interest, for approximately $240 million, excluding working capital adjustments. Champion Energy, a leading retail electric provider, is expected to serve approximately 22 million MWh of commercial, industrial and residential customer load in 2015, concentrated in Texas, PJM and the Northeast U.S. where Calpine has a substantial power generation presence. The addition of this well-established retail sales organization is expected to provide us an important outlet for directly reaching a much greater portion of the load we serve. We expect the transaction to close by the fourth quarter of 2015, subject to regulatory approvals, and will fund the acquisition with cash on hand.

Acquisition of Fore River Energy Center

On November 7, 2014, we, through our indirect, wholly-owned subsidiary Calpine Fore River Energy Center, LLC, completed the purchase of Fore River Energy Center, a power plant with a nameplate capacity of 809 MW, and related plant inventory from a subsidiary of Exelon Corporation, for approximately $530 million, excluding working capital adjustments. During the six months ended June 30, 2015, there were no material adjustments made to the initial purchase price allocation recorded in the fourth quarter of 2014 related to our acquisition of Fore River Energy Center. Although the purchase price allocation has not been finalized, we do not expect to record any material adjustments to the preliminary purchase price allocation nor do we expect to recognize any goodwill as a result of this acquisition.

3. Variable Interest Entities and Unconsolidated Investments

We consolidate all of our VIEs where we have determined that we are the primary beneficiary. There were no changes to our determination of whether we are the primary beneficiary of our VIEs for the six months ended June 30, 2015. See Note 5 in our 2014 Form 10-K for further information regarding our VIEs.

VIE Disclosures

Our consolidated VIEs include natural gas-fired power plants with an aggregate capacity of 10,266 MW and 10,365 MW at June 30, 2015 and December 31, 2014, 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. Other than

amounts contractually required, we provided support to these VIEs in the form of cash and other contributions of nil during each of the three and six months ended June 30, 2015 and nil and $40 million during the three and six months ended June 30, 2014, respectively.

Unconsolidated VIEs and Investments in Power Plants

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. 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. Whitby is a limited partnership between certain of our subsidiaries 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.

We account for these entities under the equity method of accounting and include our net equity interest in investments in power plants on our Consolidated Condensed Balance Sheets. At June 30, 2015 and December 31, 2014, our equity method investments included on our Consolidated Condensed Balance Sheets were comprised of the following (in millions):

	Ownership Interest as of June 30, 2015	June 30, 2015	December 31, 2014
Greenfield LP	50%	$ 78	$ 78
Whitby	50%	9	17
Total investments in power plants		$ 87	$ 95

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; therefore, the debt of our unconsolidated investments is not reflected on our Consolidated Condensed Balance Sheets. At June 30, 2015 and December 31, 2014, equity method investee debt was approximately $312 million and $342 million, respectively, and based on our pro rata share of each of the investments, our share of such debt would be approximately $156 million and $171 million at June 30, 2015 and December 31, 2014, respectively.

Our equity interest in the net income from Greenfield LP and Whitby for the three and six months ended June 30, 2015 and 2014, is recorded in (income) from unconsolidated investments in power plants on our Consolidated Condensed Statements of Operations. The following table sets forth details of our (income) from unconsolidated investments in power plants for the periods indicated (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Greenfield LP	$ (4)	$ —	$ (6)	$ (5)
Whitby	(3)	(4)	(6)	(8)
Total	$ (7)	$ (4)	$ (12)	$ (13)

Distributions from Greenfield LP were nil during each of the three and six months ended June 30, 2015 and 2014. Distributions from Whitby were $13 million during each of the three and six months ended June 30, 2015 and nil and $13 million during the three and six months ended June 30, 2014, respectively.

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) from GE that may be exercised between years 2017 and 2024. GE holds a put option whereby they can require us to purchase the power plant, if certain plant performance criteria are met by 2025. We determined that we are not the primary beneficiary of the Inland Empire power plant, and we do not consolidate it due to the fact that GE directs the most significant activities of the power plant including operations and maintenance.

Significant Unconsolidated Subsidiaries — Greenfield LP and Whitby met the criteria of significant unconsolidated subsidiaries for the six months ended June 30, 2015, based upon the relationship of our equity income from our investment to our consolidated net income before taxes. Aggregated summarized financial data for the six months ended June 30, 2015 and 2014 are set forth below (in millions):

Condensed Combined Statements of Operations
of Our Unconsolidated Subsidiaries
(Unaudited)

	Six Months Ended June 30,	
	2015	**2014**
Revenues	$ 98	$ 149
Operating expenses	66	111
Income from operations	32	38
Interest expense, net of interest income	10	12
Other (income) expense, net	(1)	—
Net income	$ 23	$ 26

4. Debt

Our debt at June 30, 2015 and December 31, 2014, was as follows (in millions):

	June 30, 2015	December 31, 2014
Senior Unsecured Notes	$ 3,450	$ 2,800
First Lien Term Loans	2,787	2,799
First Lien Notes	1,928	2,075
Project financing, notes payable and other	1,737	1,810
CCFC Term Loans	1,588	1,596
Capital lease obligations	201	202
Subtotal	11,691	11,282
Less: Current maturities	198	199
Total long-term debt	$ 11,493	$ 11,083

Our effective interest rate on our consolidated debt, excluding the impacts of capitalized interest and mark-to-market gains (losses) on interest rate swaps, decreased to 5.5% for the six months ended June 30, 2015, from 6.1% for the same period in 2014. The issuance of our Senior Unsecured Notes in July 2014 and February 2015 and our 2022 First Lien Term Loan in May 2015 allowed us to reduce our overall cost of debt by replacing a portion of our First Lien Notes and all of our 2018 First Lien Term Loans with debt carrying lower interest rates.

Senior Unsecured Notes

The amounts outstanding under our Senior Unsecured Notes are summarized in the table below (in millions):

	June 30, 2015	December 31, 2014
2023 Senior Unsecured Notes	$ 1,250	$ 1,250
2024 Senior Unsecured Notes	650	—
2025 Senior Unsecured Notes	1,550	1,550
Total Senior Unsecured Notes	$ 3,450	$ 2,800

In February 2015, we issued $650 million in aggregate principal amount of 5.5% senior unsecured notes due 2024 in a public offering. The 2024 Senior Unsecured Notes bear interest at 5.5% per annum with interest payable semi-annually on February 1 and August 1 of each year, beginning on August 1, 2015. The 2024 Senior Unsecured Notes were issued at par, mature on February 1, 2024 and contain substantially similar covenants, qualifications, exceptions and limitations as our 2023 Senior

Unsecured Notes and 2025 Senior Unsecured Notes. We used the net proceeds received from the issuance of our 2024 Senior Unsecured Notes to replenish cash on hand used for the acquisition of Fore River Energy Center in the fourth quarter of 2014, to repurchase approximately $147 million of our 2023 First Lien Notes and for general corporate purposes. During the first quarter of 2015, we recorded approximately $9 million in deferred financing costs related to the issuance of our 2024 Senior Unsecured Notes and approximately $19 million in debt extinguishment costs related to the partial repurchase of our 2023 First Lien Notes.

First Lien Term Loans

The amounts outstanding under our First Lien Term Loans are summarized in the table below (in millions):

	June 30, 2015	December 31, 2014
2018 First Lien Term Loans	$ —	$ 1,597
2019 First Lien Term Loan	812	816
2020 First Lien Term Loan	384	386
2022 First Lien Term Loan	1,591	—
Total First Lien Term Loans	$ 2,787	$ 2,799

On May 28, 2015, we entered into our $1.6 billion 2022 First Lien Term Loan. We used the net proceeds received, together with operating cash on hand, to repay the 2018 First Lien Term Loans. The 2022 First Lien Term Loan matures on May 27, 2022 and bears interest, at our option, at either (i) the base rate, equal to the highest of (a) the Federal Funds effective rate plus 0.50% per annum, (b) the Prime Rate or (c) the Eurodollar rate for a one month interest period plus 1.0% (in each case, as such terms are defined in the 2022 First Lien Term Loan credit agreement), plus an applicable margin of 1.75%, or (ii) LIBOR plus 2.75% per annum subject to a LIBOR floor of 0.75%. An aggregate amount equal to 0.25% of the aggregate principal amount of the 2022 First Lien Term Loan will be payable at the end of each quarter commencing in September 2015. The 2022 First Lien Term Loan contains substantially similar covenants, qualifications, exceptions and limitations as the First Lien Term Loans and First Lien Notes.

We accounted for this transaction as a debt modification rather than an extinguishment of debt and, accordingly, did not record any debt extinguishment costs associated with the repayment of our 2018 First Lien Term Loans. However, in accordance with the accounting guidance for debt modification and extinguishment, we recorded approximately $13 million in debt modification costs associated with issuance costs and approximately $6 million in deferred financing costs related to the 2022 First Lien Term Loan during the second quarter of 2015.

First Lien Notes

The amounts outstanding under our First Lien Notes are summarized in the table below (in millions):

	June 30, 2015	December 31, 2014
2022 First Lien Notes	$ 745	$ 745
2023 First Lien Notes(1)	693	840
2024 First Lien Notes	490	490
Total First Lien Notes	$ 1,928	$ 2,075

(1) On February 3, 2015, we repurchased approximately $147 million of our 2023 First Lien Notes with the proceeds from our 2024 Senior Unsecured Notes, as described in further detail above.

Corporate Revolving Facility and Other Letters of Credit Facilities

The table below represents amounts issued under our letter of credit facilities at June 30, 2015 and December 31, 2014 (in millions):

	June 30, 2015	December 31, 2014
Corporate Revolving Facility[(1)]	$ 179	$ 223
CDHI	244	214
Various project financing facilities	219	207
Total	$ 642	$ 644

(1) The Corporate Revolving Facility represents our primary revolving facility.

Fair Value of Debt

We record our debt instruments based on contractual terms, net of any applicable premium or discount. The following table details the fair values and carrying values of our debt instruments at June 30, 2015 and December 31, 2014 (in millions):

	June 30, 2015		December 31, 2014	
	Fair Value	Carrying Value	Fair Value	Carrying Value
Senior Unsecured Notes	$ 3,347	$ 3,450	$ 2,832	$ 2,800
First Lien Term Loans	2,768	2,787	2,769	2,799
First Lien Notes	2,059	1,928	2,247	2,075
Project financing, notes payable and other[(1)]	1,660	1,629	1,734	1,688
CCFC Term Loans	1,564	1,588	1,540	1,596
Total	$ 11,398	$ 11,382	$ 11,122	$ 10,958

(1) Excludes a lease that is accounted for as a failed sale-leaseback transaction under U.S. GAAP.

We measure the fair value of our Senior Unsecured Notes, First Lien Term Loans, First Lien Notes and CCFC Term Loans using market information, including quoted market prices or dealer quotes for the identical liability when traded as an asset (categorized as level 2). We measure the fair value of our project financing, notes payable and other debt instruments using discounted cash flow analyses based on our current borrowing rates for similar types of borrowing arrangements (categorized as level 3). We do not have any debt instruments with fair value measurements categorized as level 1 within the fair value hierarchy.

5. 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 our restricted cash on our Consolidated Condensed 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 Posted with Us by Our Counterparties — Margin deposits and margin deposits posted with us by our counterparties represent cash collateral paid between our counterparties and us to support our commodity contracts. Our margin deposits and margin deposits posted with us 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); changing commodity market prices, primarily 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. 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 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. We use other qualitative assessments 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 power and natural gas swaps, futures and options traded on the NYMEX or Intercontinental Exchange.

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 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 may consist of 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 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. 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.

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. The following tables present our financial assets and liabilities that were accounted for at fair value on a recurring basis as of June 30, 2015 and December 31, 2014, by level within the fair value hierarchy:

	Assets and Liabilities with Recurring Fair Value Measures as of June 30, 2015			
	Level 1	Level 2	Level 3	Total
	(in millions)			
Assets:				
Cash equivalents[1]	$ 577	$ —	$ —	$ 577
Margin deposits	103	—	—	103
Commodity instruments:				
Commodity exchange traded futures and swaps contracts	1,684	—	—	1,684
Commodity forward contracts[2]	—	284	273	557
Interest rate swaps	—	3	—	3
Total assets	$ 2,364	$ 287	$ 273	$ 2,924
Liabilities:				
Margin deposits posted with us by our counterparties	$ 53	$ —	$ —	$ 53
Commodity instruments:				
Commodity exchange traded futures and swaps contracts	1,506	—	—	1,506
Commodity forward contracts[2]	—	219	30	249
Interest rate swaps	—	105	—	105
Total liabilities	$ 1,559	$ 324	$ 30	$ 1,913

	Assets and Liabilities with Recurring Fair Value Measures as of December 31, 2014			
	Level 1	Level 2	Level 3	Total
	(in millions)			
Assets:				
Cash equivalents[1]	$ 896	$ —	$ —	$ 896
Margin deposits	96	—	—	96
Commodity instruments:				
Commodity exchange traded futures and swaps contracts	2,134	—	—	2,134
Commodity forward contracts[2]	—	195	164	359
Interest rate swaps	—	4	—	4
Total assets	$ 3,126	$ 199	$ 164	$ 3,489
Liabilities:				
Margin deposits posted with us by our counterparties	$ 47	$ —	$ —	$ 47
Commodity instruments:				
Commodity exchange traded futures and swaps contracts	1,870	—	—	1,870
Commodity forward contracts[2]	—	163	79	242
Interest rate swaps	—	114	—	114
Total liabilities	$ 1,917	$ 277	$ 79	$ 2,273

(1) As of June 30, 2015 and December 31, 2014, we had cash equivalents of $367 million and $679 million included in cash and cash equivalents and $210 million and $217 million included in restricted cash, respectively.

(2) Includes OTC swaps and options.

At June 30, 2015 and December 31, 2014, the derivative instruments classified as level 3 primarily included commodity contracts, which are classified as level 3 because the contract terms relate to a delivery location or tenor for which observable market rate information is not available. The fair value of the net derivative position classified as level 3 is predominantly driven by market commodity prices. The following table presents quantitative information for the unobservable inputs used in our most significant level 3 fair value measurements at June 30, 2015 and December 31, 2014:

Quantitative Information about Level 3 Fair Value Measurements

	June 30, 2015			
	Fair Value, Net Asset (Liability)	**Valuation Technique**	**Significant Unobservable Input**	**Range**
	(in millions)			
Power Contracts	$ 237	Discounted cash flow	Market price (per MWh)	$12.68 — $121.40/MWh
Power Congestion Products	$ 7	Discounted cash flow	Market price (per MWh)	$(19.56) — $19.56/MWh

	December 31, 2014			
	Fair Value, Net Asset (Liability)	**Valuation Technique**	**Significant Unobservable Input**	**Range**
	(in millions)			
Power Contracts	$ 74	Discounted cash flow	Market price (per MWh)	$14.00 — $122.79/MWh
Natural Gas Contracts	$ 5	Discounted cash flow	Market price (per MMBtu)	$1.00 — $10.86/MMBtu
Power Congestion Products	$ 9	Discounted cash flow	Market price (per MWh)	$(19.56) — $19.56/MWh

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 periods indicated (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	**2014**	**2015**	**2014**
Balance, beginning of period	$ 203	$ 8	$ 85	$ 14
Realized and mark-to-market gains (losses):				
Included in net income:				
Included in operating revenues[1]	45	(7)	176	(15)
Included in fuel and purchased energy expense[2]	—	—	2	6
Purchases and settlements:				
Purchases	2	—	4	—
Settlements	(10)	(3)	(21)	(6)
Transfers in and/or out of level 3[3]:				
Transfers into level 3[4]	—	2	—	—
Transfers out of level 3[5]	3	(9)	(3)	(8)
Balance, end of period	$ 243	$ (9)	$ 243	$ (9)
Change in unrealized gains (losses) relating to instruments still held at end of period	$ 45	$ (7)	$ 178	$ (9)

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(1) For power contracts and other power-related products, included on our Consolidated Condensed Statements of Operations.

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

(3) We transfer amounts among levels of the fair value hierarchy as of the end of each period. There were no transfers into or out of level 1 for each of the three and six months ended June 30, 2015 and 2014.

(4) There were no transfers out of level 2 into level 3 for each of the three and six months ended June 30, 2015 and for the six months ended June 30, 2014. We had $2 million in gains transferred out of level 2 into level 3 for the three months ended June 30, 2014, due to changes in market liquidity in various power markets.

(5) We had $3 million in losses and $(9) million in gains transferred out of level 3 into level 2 for the three months ended June 30, 2015 and 2014, respectively, and $(3) million and $(8) million in gains transferred out of level 3 into level 2 for the six months ended June 30, 2015 and 2014, respectively, due to changes in market liquidity in various power markets.

6. 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, environmental products 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.

We also engage in limited trading activities related to our commodity derivative portfolio as authorized by our Board of Directors and monitored by our Chief Risk Officer and Risk Management Committee of senior management. These transactions are executed primarily for the purpose of providing improved price and price volatility discovery, greater market access, and profiting from our market knowledge, all of which benefit our asset hedging activities. Our trading gains and losses were not material for the three and six months ended June 30, 2015 and 2014.

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 June 30, 2015, the maximum length of time over which we were hedging using interest rate derivative instruments designated as cash flow hedges was 8 years.

As of June 30, 2015 and December 31, 2014, the net forward notional buy (sell) position of our outstanding commodity and interest rate swap contracts that did not qualify or were not designated under the normal purchase normal sale exemption were as follows (in millions):

	Notional Amounts	
Derivative Instruments	**June 30, 2015**	**December 31, 2014**
Power (MWh)	(99)	(62)
Natural gas (MMBtu)	874	291
Environmental credits (Tonnes)	3	—
Interest rate swaps	$ 1,411	$ 1,431

Certain of our derivative instruments contain credit risk-related contingent provisions that require us to maintain collateral balances consistent with our credit ratings. 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 notch downgrade from its current level would be material. The aggregate fair value of our derivative liabilities with credit risk-related contingent provisions as of June 30, 2015, was $12 million for which we have posted collateral of $9 million by posting margin deposits or granting additional first priority liens on the assets currently subject to first priority liens under our First Lien Notes, First Lien Term Loans and Corporate Revolving Facility. However, if our credit rating were downgraded by one notch from its current level, we estimate that additional collateral of $14 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 Condensed Statements of Operations until the period of delivery. Revenues and expenses derived from instruments that qualified 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 on our Consolidated Condensed Statements of Cash Flows unless they contain an other-than-insignificant financing element in which case their cash flows are classified within financing activities.

Cash Flow Hedges — We only apply hedge accounting to our interest rate derivative instruments. We report the effective portion of the mark-to-market gain or loss on our interest rate swaps 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 interest rate hedging instruments are recognized currently in earnings as a component of interest expense. 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.

Derivatives Not Designated as Hedging Instruments — We enter into power, natural gas, interest rate and environmental product 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 commodity derivatives not designated as hedging instruments are recognized currently in earnings and are separately stated on our Consolidated Condensed Statements of Operations in mark-to-market gain/loss as a component of operating revenues (for power and Heat Rate swaps and options) and fuel and purchased energy expense (for natural gas contracts, environmental product contracts, swaps and options). Changes in fair value of interest rate derivatives not designated as hedging instruments are recognized currently in earnings as interest expense.

Derivatives Included on Our Consolidated Condensed Balance Sheets

The following tables present the fair values of our derivative instruments recorded on our Consolidated Condensed Balance Sheets by location and hedge type at June 30, 2015 and December 31, 2014 (in millions):

	June 30, 2015		
	Commodity Instruments	Interest Rate Swaps	Total Derivative Instruments
Balance Sheet Presentation			
Current derivative assets	$ 1,607	$ —	$ 1,607
Long-term derivative assets	634	3	637
Total derivative assets	$ 2,241	$ 3	$ 2,244
Current derivative liabilities	$ 1,365	$ 42	$ 1,407
Long-term derivative liabilities	390	63	453
Total derivative liabilities	$ 1,755	$ 105	$ 1,860
Net derivative asset (liabilities)	$ 486	$ (102)	$ 384

	December 31, 2014		
	Commodity Instruments	Interest Rate Swaps	Total Derivative Instruments
Balance Sheet Presentation			
Current derivative assets	$ 2,058	$ —	$ 2,058
Long-term derivative assets	435	4	439
Total derivative assets	$ 2,493	$ 4	$ 2,497
Current derivative liabilities	$ 1,738	$ 44	$ 1,782
Long-term derivative liabilities	374	70	444

Total derivative liabilities	$ 2,112	$ 114	$ 2,226
Net derivative asset (liabilities)	$ 381	$ (110)	$ 271

	June 30, 2015		December 31, 2014	
	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	$ 3	$ 105	$ 4	$ 112
Total derivatives designated as cash flow hedging instruments	$ 3	$ 105	$ 4	$ 112
Derivatives not designated as hedging instruments:				
Commodity instruments	$ 2,241	$ 1,755	$ 2,493	$ 2,112
Interest rate swaps	—	—	—	2
Total derivatives not designated as hedging instruments	$ 2,241	$ 1,755	$ 2,493	$ 2,114
Total derivatives	$ 2,244	$ 1,860	$ 2,497	$ 2,226

We elected not to offset fair value amounts recognized as derivative instruments on our Consolidated Condensed Balance Sheets that are executed with the same counterparty under master netting arrangements or other contractual netting provisions negotiated with the counterparty. Our netting arrangements include a right to set off or net together purchases and sales of similar products in the margining or settlement process. In some instances, we have also negotiated cross commodity netting rights which allow for the net presentation of activity with a given counterparty regardless of product purchased or sold. We also post cash collateral in support of our derivative instruments which may also be subject to a master netting arrangement with the same counterparty.

The tables below set forth our net exposure to derivative instruments after offsetting amounts subject to a master netting arrangement with the same counterparty at June 30, 2015 and December 31, 2014 (in millions):

	June 30, 2015			
		Gross Amounts Not Offset on the Consolidated Condensed Balance Sheets		
	Gross Amounts Presented on our Consolidated Condensed Balance Sheets	Derivative Asset (Liability) not Offset on the Consolidated Condensed Balance Sheets	Margin/Cash (Received) Posted [(1)]	Net Amount
Derivative assets:				
Commodity exchange traded futures and swaps contracts	$ 1,684	$ (1,506)	$ (178)	$ —
Commodity forward contracts	557	(231)	(9)	317
Interest rate swaps	3	—	—	3
Total derivative assets	$ 2,244	$ (1,737)	$ (187)	$ 320
Derivative (liabilities):				
Commodity exchange traded futures and swaps contracts	$ (1,506)	$ 1,506	$ —	$ —
Commodity forward contracts	(249)	231	9	(9)
Interest rate swaps	(105)	—	—	(105)
Total derivative (liabilities)	$ (1,860)	$ 1,737	$ 9	$ (114)
Net derivative assets (liabilities)	$ 384	$ —	$ (178)	$ 206

	December 31, 2014							
	Gross Amounts Not Offset on the Consolidated Condensed Balance Sheets							
	Gross Amounts Presented on our Consolidated Condensed Balance Sheets		Derivative Asset (Liability) not Offset on the Consolidated Condensed Balance Sheets		Margin/Cash (Received) Posted (1)		Net Amount	
Derivative assets:								
Commodity exchange traded futures and swaps contracts	$	2,134	$	(1,865)	$	(269)	$	—
Commodity forward contracts		359		(222)		—		137
Interest rate swaps		4		—		—		4
Total derivative assets	$	2,497	$	(2,087)	$	(269)	$	141
Derivative (liabilities):								
Commodity exchange traded futures and swaps contracts	$	(1,870)	$	1,865	$	5	$	—
Commodity forward contracts		(242)		222		10		(10)
Interest rate swaps		(114)		—		—		(114)
Total derivative (liabilities)	$	(2,226)	$	2,087	$	15	$	(124)
Net derivative assets (liabilities)	$	271	$	—	$	(254)	$	17

(1) Negative balances represent margin deposits posted with us by our counterparties related to our derivative activities that are subject to a master netting arrangement. Positive balances reflect margin deposits and natural gas and power prepayments posted by us with our counterparties related to our derivative activities that are subject to a master netting arrangement. See Note 7 for a further discussion of our collateral.

Derivatives Included on Our Consolidated Condensed 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 Condensed Statements of Operations as a component of mark-to-market activity within our earnings.

The following tables detail the components of our total activity for both the net realized gain (loss) and the net mark-to-market gain (loss) recognized from our derivative instruments in earnings and where these components were recorded on our Consolidated Condensed Statements of Operations for the periods indicated (in millions):

	Three Months Ended June 30,				Six Months Ended June 30,			
	2015		2014		2015		2014	
Realized gain (loss)[(1)]								
Commodity derivative instruments	$	104	$	18	$	163	$	(21)
Total realized gain (loss)	$	104	$	18	$	163	$	(21)
Mark-to-market gain (loss)[(2)]								
Commodity derivative instruments	$	(1)	$	141	$	69	$	68
Interest rate swaps		—		1		1		2
Total mark-to-market gain (loss)	$	(1)	$	142	$	70	$	70
Total activity, net	$	103	$	160	$	233	$	49

(1) Does not include the realized value associated with derivative instruments that settle through physical delivery.

(2)

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

	Three Months Ended June 30,				Six Months Ended June 30,			
	2015		2014		2015		2014	
Realized and mark-to-market gain (loss)								
Derivatives contracts included in operating revenues	$	115	$	158	$	234	$	(79)
Derivatives contracts included in fuel and purchased energy expense		(12)		1		(2)		126
Interest rate swaps included in interest expense		—		1		1		2
Total activity, net	$	103	$	160	$	233	$	49

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 periods indicated (in millions):

	Three Months Ended June 30,				Three Months Ended June 30,				
	Gain (Loss) Recognized in OCI (Effective Portion)				Gain (Loss) Reclassified from AOCI into Income (Effective Portion)[3][4]				
	2015		2014		2015		2014		Affected Line Item on the Consolidated Condensed Statements of Operations
Interest rate swaps[1][2]	$	14	$	(9)	$	(12)	$	(13)	Interest expense

	Six Months Ended June 30,				Six Months Ended June 30,				
	Gain (Loss) Recognized in OCI (Effective Portion)				Gain (Loss) Reclassified from AOCI into Income (Effective Portion)[3][4]				
	2015		2014		2015		2014		Affected Line Item on the Consolidated Condensed Statements of Operations
Interest rate swaps[1][2]	$	8	$	(9)	$	(24)	$	(26)	Interest expense

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(1) We did not record any gain (loss) on hedge ineffectiveness related to our interest rate swaps designated as cash flow hedges during the three and six months ended June 30, 2015 and 2014.

(2) We recorded an income tax expense of nil for each of the three and six months ended June 30, 2015 and 2014, in AOCI related to our cash flow hedging activities.

(3) Cumulative cash flow hedge losses attributable to Calpine, net of tax, remaining in AOCI were $142 million and $149 million at June 30, 2015 and December 31, 2014, respectively. Cumulative cash flow hedge losses attributable to the noncontrolling interest, net of tax, remaining in AOCI were $11 million and $12 million at June 30, 2015 and December 31, 2014, respectively.

(4) Includes a loss of $5 million and $10 million for the three and six months ended June 30, 2014, respectively, that was reclassified from AOCI to interest expense, where the hedged transactions are no longer expected to occur.

We estimate that pre-tax net losses of $46 million would be reclassified from AOCI into interest expense 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 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.

7. 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 June 30, 2015 and December 31, 2014 (in millions):

	June 30, 2015	December 31, 2014
Margin deposits[1]	$ 103	$ 96
Natural gas and power prepayments	25	22
Total margin deposits and natural gas and power prepayments with our counterparties[2]	$ 128	$ 118
Letters of credit issued	$ 452	$ 450
First priority liens under power and natural gas agreements	24	48
First priority liens under interest rate swap agreements	106	116
Total letters of credit and first priority liens with our counterparties	$ 582	$ 614
Margin deposits posted with us by our counterparties[1][3]	$ 53	$ 47
Letters of credit posted with us by our counterparties	52	61
Total margin deposits and letters of credit posted with us by our counterparties	$ 105	$ 108

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(1) Balances are subject to master netting arrangements and presented on a gross basis on our Consolidated Condensed 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, and we do not offset amounts recognized for the right to reclaim, or the obligation to return, cash collateral with corresponding derivative instrument fair values. See Note 6 for further discussion of our derivative instruments subject to master netting arrangements.

(2) At June 30, 2015 and December 31, 2014, $114 million and $109 million, respectively, were included in margin deposits and other prepaid expense and $14 million and $9 million, respectively, were included in other assets on our Consolidated Condensed Balance Sheets.

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

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

8. Income Taxes

Income Tax Expense (Benefit)

The table below shows our consolidated income tax expense (benefit) from continuing operations (excluding noncontrolling interest) and our effective tax rates for the periods indicated (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Income tax expense (benefit)	$ 5	$ 15	$ 4	$ (4)
Effective tax rate	21%	10%	31%	(3)%

Our income tax rates do not bear a customary relationship to statutory income tax rates primarily as a result of the impact of our NOLs, changes in unrecognized tax benefits and valuation allowances. For the three and six months ended June 30, 2015 and 2014, our income tax expense (benefit) is largely comprised of discrete tax items and estimated state and foreign income taxes in jurisdictions where we do not have NOLs. See Note 10 in our 2014 Form 10-K for further information regarding our NOLs.

Income Tax Audits — We remain subject to periodic audits and reviews by taxing authorities; however, we do not expect these audits will have a material effect on our tax provision. Any NOLs we claim in future years to reduce taxable income could

be subject to IRS examination regardless of when the NOLs occurred. Any adjustment of state or federal returns would likely result in a reduction of deferred tax assets rather than a cash payment of income taxes in tax jurisdictions where we have NOLs.

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 earnings history, we are unable to assume future profits; however, we are able to consider available tax planning strategies.

Unrecognized Tax Benefits — At June 30, 2015, we had unrecognized tax benefits of $54 million. If recognized, $13 million of our unrecognized tax benefits could impact the annual effective tax rate and $41 million, related to deferred tax assets, could be offset against the recorded valuation allowance resulting in no impact on our effective tax rate. We had accrued interest and penalties of $11 million for income tax matters at June 30, 2015. We recognize interest and penalties related to unrecognized tax benefits in income tax benefit on our Consolidated Condensed Statements of Operations.

9. Earnings per Share

We include restricted stock units for which no future service is required as a condition to the delivery of the underlying common stock in our calculation of weighted average shares outstanding. Reconciliations of the amounts used in the basic and diluted earnings per common share computations for the three and six months ended June 30, 2015 and 2014, are as follows (shares in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Diluted weighted average shares calculation:				
Weighted average shares outstanding (basic)	366,975	416,507	369,938	418,296
Share-based awards	2,971	4,841	3,466	4,401
Weighted average shares outstanding (diluted)	369,946	421,348	373,404	422,697

We excluded the following items from diluted earnings per common share for the three and six months ended June 30, 2015 and 2014, because they were anti-dilutive (shares in thousands):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Share-based awards	5,042	2,854	5,042	5,066

10. Stock-Based Compensation

Equity Classified Share-Based Awards

Stock-based compensation expense recognized for our equity classified share-based awards was $7 million and $8 million for the three months ended June 30, 2015 and 2014, respectively, and $16 million and $17 million for the six months ended June 30, 2015 and 2014, 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 six months ended June 30, 2015 and 2014. At June 30, 2015, there was unrecognized compensation cost of $38 million related to restricted stock which is expected to be recognized over a weighted average period of 1.5 years.

A summary of our restricted stock and restricted stock unit activity for the Calpine Equity Incentive Plans for the six months ended June 30, 2015, is as follows:

	Number of Restricted Stock Awards		Weighted Average Grant-Date Fair Value
Nonvested — December 31, 2014	4,201,868	$	18.01
Granted	1,572,761	$	21.42
Forfeited	157,807	$	19.40
Vested	1,577,169	$	16.52
Nonvested — June 30, 2015	4,039,653	$	19.86

The total fair value of our restricted stock and restricted stock units that vested during the six months ended June 30, 2015 and 2014 was approximately $33 million and $30 million, respectively.

Liability Classified Share-Based Awards

Performance share units granted under the Equity Plan are settled in cash with payouts based on the relative performance of Calpine's TSR over a three-year performance period compared with the TSR performance of the S&P 500 companies over the same period. The performance share units vest on the last day of the performance period and will be settled in cash; thus, these awards are classified as a liability and measured at fair value using a Monte Carlo simulation model at each reporting date until settlement. Stock-based compensation expense recognized related to our liability classified share-based awards was $(6) million and $4 million for the three months ended June 30, 2015 and 2014, respectively, and $(4) million and $5 million for the six months ended June 30, 2015 and 2014, respectively.

A summary of our performance share unit activity for the six months ended June 30, 2015, is as follows:

	Number of Performance Share Units		Weighted Average Grant-Date Fair Value
Nonvested — December 31, 2014	867,479	$	21.93
Granted	365,667	$	23.91
Forfeited	45,654	$	22.09
Vested[(1)]	8,254	$	22.56
Nonvested — June 30, 2015	1,179,238	$	22.53

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(1) In accordance with the applicable performance share unit agreements, performance share units granted to employees who meet the retirement eligibility requirements stipulated in the Equity Plan are fully vested upon the later of the date on which the employee becomes eligible to retire or one-year anniversary of the grant date.

For a further discussion of the Calpine Equity Incentive Plans, see Note 12 in our 2014 Form 10-K.

11. Commitments and Contingencies

Litigation

We are party to various litigation matters, including regulatory and administrative proceedings arising out of the normal course of business. At the present time, we do not expect that the outcome of any of these proceedings, individually or in the aggregate, will have a material adverse effect on our financial condition, results of operations or cash flows.

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 on our financial condition, 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 on our financial condition, results of operations or cash flows.

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 operation of our power plants. At the present time, we do not 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.

Bay Area Air Quality Management District ("BAAQMD"). On March 13, 2014, the Hearing Board of the BAAQMD entered into a stipulated conditional order for abatement agreed to by Russell City Energy Company, LLC ("RCEC"), our indirect, majority-owned subsidiary, and the BAAQMD concerning a violation of the vendor-guaranteed water droplet drift rate for RCEC's cooling tower discovered during initial performance testing. RCEC installed additional drift eliminators and came into compliance with its water droplet drift rate on April 17, 2014. The BAAQMD issued a notice of violation for this event on April 24, 2015. The BAAQMD continues to reserve its rights to assert any penalty claims associated with this violation and RCEC continues to reserve its rights to assert any defenses to such claims in future proceedings.

12. Segment 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. During the third quarter of 2014, we altered the composition of our geographic segments to combine our former North and Southeast segments into one segment which was renamed the East segment. This change reflects the manner in which our geographic information is presented internally to our chief operating decision maker following the sale of six power plants in July 2014 that composed a substantial portion of our former Southeast segment. Thus, beginning in the third quarter of 2014, our reportable segments were West (including geothermal), Texas and East (including Canada). We continue to evaluate the manner in which we assess our performance, including our segments, which may result in future changes to the composition of our geographic segments.

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).

	Three Months Ended June 30, 2015				
	West	Texas	East	Consolidation and Elimination	Total
Revenues from external customers	$ 421	$ 570	$ 451	$ —	$ 1,442
Intersegment revenues	—	5	2	(7)	—
Total operating revenues	$ 421	$ 575	$ 453	$ (7)	$ 1,442
Commodity Margin	$ 240	$ 170	$ 247	$ —	$ 657
Add: Mark-to-market commodity activity, net and other[1]	(14)	10	30	(7)	19
Less:					
Plant operating expense	120	82	77	(7)	272
Depreciation and amortization expense	65	50	45	—	160
Sales, general and other administrative expense	6	15	9	—	30
Other operating expenses	10	2	8	—	20
(Income) from unconsolidated investments in power plants	—	—	(7)	—	(7)
Income from operations	25	31	145	—	201
Interest expense, net of interest income					157
Debt modification costs and other (income) expense, net					18
Income before income taxes					$ 26

	Three Months Ended June 30, 2014				
	West	Texas	East	Consolidation and Elimination	Total
Revenues from external customers	$ 487	$ 960	$ 492	$ —	$ 1,939
Intersegment revenues	1	3	27	(31)	—
Total operating revenues	$ 488	$ 963	$ 519	$ (31)	$ 1,939
Commodity Margin[2]	$ 228	$ 177	$ 227	$ —	$ 632
Add: Mark-to-market commodity activity, net and other[1]	21	184	(24)	(8)	173
Less:					
Plant operating expense	95	83	103	(7)	274
Depreciation and amortization expense	58	48	40	1	147
Sales, general and other administrative expense	7	18	12	1	38
Other operating expenses	15	1	9	(4)	21
(Income) from unconsolidated investments in power plants	—	—	(4)	—	(4)
Income from operations	74	211	43	1	329
Interest expense, net of interest income					167
Other (income) expense, net					6
Income before income taxes					$ 156

	Six Months Ended June 30, 2015				
	West	Texas	East	Consolidation and Elimination	Total
Revenues from external customers	$ 936	$ 1,151	$ 1,001	$ —	$ 3,088
Intersegment revenues	2	8	4	(14)	—
Total operating revenues	$ 938	$ 1,159	$ 1,005	$ (14)	$ 3,088
Commodity Margin	$ 458	$ 319	$ 415	$ —	$ 1,192
Add: Mark-to-market commodity activity, net and other[3]	105	51	(22)	(14)	120
Less:					
Plant operating expense	226	171	149	(14)	532
Depreciation and amortization expense	132	99	87	—	318
Sales, general and other administrative expense	16	32	19	—	67
Other operating expenses	20	4	16	—	40
(Income) from unconsolidated investments in power plants	—	—	(12)	—	(12)
Income from operations	169	64	134	—	367
Interest expense, net of interest income					310
Debt modification and extinguishment costs and other (income) expense, net					39
Income before income taxes					$ 18

	Six Months Ended June 30, 2014				
	West	Texas	East	Consolidation and Elimination	Total
Revenues from external customers	$ 978	$ 1,607	$ 1,319	$ —	$ 3,904
Intersegment revenues	3	15	44	(62)	—
Total operating revenues	$ 981	$ 1,622	$ 1,363	$ (62)	$ 3,904
Commodity Margin[2]	$ 430	$ 298	$ 549	$ —	$ 1,277
Add: Mark-to-market commodity activity, net and other[3]	50	138	(35)	(17)	136
Less:					
Plant operating expense	200	173	182	(16)	539
Depreciation and amortization expense	118	90	91	1	300
Sales, general and other administrative expense	17	30	24	—	71
Other operating expenses	27	3	16	(3)	43
(Income) from unconsolidated investments in power plants	—	—	(13)	—	(13)
Income from operations	118	140	214	1	473
Interest expense, net of interest income					332
Debt extinguishment costs and other (income) expense, net					17
Income before income taxes					$ 124

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(1) Includes $(18) million and $(27) million of lease levelization and $3 million and $3 million of amortization expense for the three months ended June 30, 2015 and 2014, respectively.

(2)

Commodity Margin related to the six power plants sold in our East segment on July 3, 2014, was $42 million and $81 million for the three and six months ended June 30, 2014, respectively.

(3) Includes $(42) million and $(56) million of lease levelization and $7 million and $7 million of amortization expense for the six months ended June 30, 2015 and 2014, respectively.

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

Forward-Looking Information

This Management's Discussion and Analysis of Financial Condition and Results of Operations should be read in conjunction with our accompanying Consolidated Condensed Financial Statements and related Notes. See the cautionary statement regarding forward-looking statements at the beginning of this Report for a description of important factors that could cause actual results to differ from expected results.

Introduction and Overview

We are one of the largest wholesale power generators 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 (included in our West segment), Texas (included in our Texas segment) and the Northeast region (included in our East segment) 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. As a result of our investment in cleaner power generation, we have become a recognized leader in developing, constructing, owning and operating an environmentally responsible portfolio of flexible and reliable power plants.

In order to manage our various physical assets and contractual obligations, we execute commodity and commodity transportation agreements within the guidelines of our Risk Management Policy. We purchase primarily natural gas and some fuel oil as fuel for our power plants and engage in related natural gas transportation and storage transactions. We purchase electric transmission rights to deliver power to our customers. We also enter into natural gas, power and other physical and financial contracts to hedge certain business risks and optimize our portfolio of power plants. Seasonality and weather can have a significant impact on our results of operations and are also considered in our hedging and optimization activities.

Our capital allocation philosophy seeks to maximize levered cash returns to equity on a per share basis. We currently consider the repurchases of our own shares of common stock as an attractive investment opportunity, and we utilize the expected returns from this investment as the benchmark against which we evaluate all other capital allocation decisions. We believe this philosophy closely aligns our objectives with those of our shareholders.

Our goal is to be recognized as the premier power generation company in the U.S. as measured by our employees, shareholders, customers and policy-makers 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, and by pursuing opportunities to improve our fleet performance and reduce operating costs. We continue to make significant progress to deliver financially disciplined growth, to enhance shareholder value through disciplined capital allocation including the return of capital to shareholders and to manage the balance sheet for future growth and success with the following achievements during 2015:

- We produced approximately 54 million MWh of electricity during the six months ended June 30, 2015.
- Our entire fleet achieved a forced outage factor of 1.7% and a starting reliability of 98% during the six months ended June 30, 2015.
- In 2015, through the filing of this Report, we repurchased a total of 23.3 million shares of our common stock for approximately $475 million at an average price of $20.42 per share.
- In February 2015, we issued $650 million in aggregate principal amount of 5.5% senior unsecured notes due 2024. We used the net proceeds to replenish cash on hand used for the acquisition of Fore River Energy Center in the fourth quarter of 2014, to repurchase approximately $147 million of our 2023 First Lien Notes and for general corporate purposes.
- In May 2015, we repaid our 2018 First Lien Term Loans with the proceeds from the 2022 First Lien Term Loan which extended the maturity and reduced the interest rate on approximately $1.6 billion of corporate debt.
- In June 2015, our Garrison Energy Center commenced commercial operations, bringing online approximately 309 MW of combined-cycle, natural gas-fired capacity.
- During the second quarter of 2015, we began construction of our 760 MW York 2 Energy Center and expect commercial operations to commence during the second quarter of 2017.

- In July 2015, we entered into an agreement to purchase Champion Energy for approximately $240 million, excluding working capital adjustments. The addition of this well-established retail sales organization is expected to provide us an important outlet for directly reaching a much greater portion of the load we serve.
- We successfully originated several new contracts with customers in our West, Texas and East segments, including those related to our Delta Energy Center, Geysers Assets, Mankato Power Plant and Texas power plant fleet. The execution of two of these PPAs with customers in Texas and the East will facilitate the construction of a 418 MW natural gas-fired peaking power plant to be co-located with our Guadalupe Energy Center and the 345 MW expansion of our Mankato Power Plant.

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 and East (including Canada).

Our portfolio, including partnership interests, consists of 83 power plants, including one under construction, located throughout 18 states in the U.S. and in Canada, with an aggregate current generation capacity of 26,587 MW and 760 MW under construction. Our fleet, including projects under construction, consists of 67 natural gas-fired combustion turbine-based plants, one fuel oil-fired steam-based plant, 14 geothermal steam turbine-based plants and one photovoltaic solar plant. Our segments have an aggregate generation capacity of 7,425 MW in the West, 9,427 MW in Texas and 9,735 MW with an additional 760 MW under construction in the East.

Legislative and Regulatory Update

We are subject to complex and stringent energy, environmental and other laws and regulations at the federal, state and local levels as well as rules within the ISO and RTO markets in which we participate. Federal and state legislative and regulatory actions, including those by ISO/RTOs, continue to change how our business is regulated. We are actively participating in these debates at the federal, regional, state and ISO/RTO levels. Significant updates are discussed below. For a further discussion of the environmental and other governmental regulations that affect us, see "— Governmental and Regulatory Matters" in Part I, Item 1 of our 2014 Form 10-K.

CAISO

The CPUC and CAISO continue to evaluate capacity procurement policies and products for the California power market. With the expectation of significant increases in renewables, both entities are evaluating the need for operational flexibility, including the ability to start and ramp quickly as well as the ability to operate efficiently at low output levels or cycle off. We are an active participant in these discussions and support products and policies that would provide appropriate compensation for the required attributes. As these proceedings are ongoing, we cannot predict the ultimate impact on our financial condition, results of operations or cash flows, though we believe our fleet offers many features that can, and do, provide operational flexibility to the power markets.

ERCOT

The PUCT is considering changes regarding its approach to resource adequacy, including price formation. ERCOT successfully launched the Operating Reserve Demand Curve ("ORDC") functionality on June 1, 2014. This application produces a price "adder" to the clearing price of energy that increases as reserve capacity declines. As follow up to the ORDC, ERCOT has implemented a stakeholder approved reliability deployment adder that reflects the value of ISO out of merit actions and corrects real time price reversals. The adder became effective prior to the 2015 peak summer season. The PUCT continues to consider the appropriate reliability standard that should be used to set ERCOT's planning reserve margin. As these proceedings are ongoing and the timing of these changes is uncertain, we cannot predict the ultimate impact on our financial condition, results of operations or cash flows.

PJM

PJM experienced several unusual cold weather events during January 2014. PJM maintained system reliability, but the system was challenged. In order to address some of these challenges, PJM filed proposed capacity market rule changes in December 2014 which include stronger performance incentives and more significant penalties for failure to perform during peak power system conditions. On June 9, 2015, the FERC approved PJM's proposed changes with minor alterations, and on July 22, 2015, the FERC granted rehearing of its June 9, 2015 order in order to permit qualifying demand response and energy efficiency resources to participate in the transition auctions. As a result of the FERC's orders, PJM scheduled the start of its 2018/2019 base residual auction to take place on August 10, 2015. The dates for the transition auctions for the 2016/2017 and 2017/2018 delivery periods have not yet been established. All of these auctions will include the capacity performance measures approved by the FERC. We support PJM's capacity market rule changes and believe that, overall, they enhance the competitiveness and reliability of the PJM power market.

ISO-NE

ISO-NE continues to express concern related to the adequacy of natural gas transmission infrastructure and, for the past two years, has taken various out-of-market actions to ensure winter reliability over the near term for states in the northeast region. The FERC is currently considering proposals to extend the winter reliability program for an additional three year period. Over the longer term, the FERC has approved significant changes to the operation of the region's capacity market that became effective with the 2015 Forward Capacity Auction ("FCA"). The ISO's new "Pay for Performance" capacity market will result in significantly higher penalties for assets that fail to perform during shortage events beginning with the 2018-2019 commitment period. The prospect of these performance requirements, combined with recent capacity retirements in the region, resulted in significantly higher 2015 FCA clearing prices than were seen in recent years. The FERC also approved a two-year extension of the "lock-in" period for new generation, allowing new generating assets that clear an FCA to lock in their cleared price for a total of seven years.

Cross-State Air Pollution Rule ("CSAPR") and Mercury and Air Toxics Standards ("MATS")

On April 29, 2014, the U.S. Supreme Court in *EME Homer City Generation v. EPA* ruled in favor of the EPA by reversing and remanding the decision of the U.S. Court of Appeals for the District of Columbia Circuit ("D.C. Circuit") invalidating CSAPR. On October 23, 2014, the D.C. Circuit lifted the stay so that CSAPR can be fully implemented. On December 3, 2014, the EPA issued administrative regulations and a Notice of Data Availability that clearly defined requirements for implementation of CSAPR. As a result of the U.S. Supreme Court ruling and the EPA's subsequent regulations, CSAPR became effective on January 1, 2015, including all of the original provisions of CSAPR, with a three year delay on the timelines proposed in the original rule provisions. The D.C. Circuit heard oral arguments regarding the remaining legal issues on February 25, 2015.

On April 15, 2014, the D.C. Circuit rejected all legal challenges to the EPA's MATS regulation in the *White Stallion Energy Center, LLC, et al v. EPA.* case, which included challenges by over 20 states, industry groups and companies. In response to further challenges by the petitioners, the U.S. Supreme Court granted petitions for certiorari in November 2014 and heard oral arguments on March 25, 2015. On June 29, 2015, the U.S. Supreme Court reversed the decision of the D.C. Circuit and remanded the case for further action. At this time, the ultimate outcome of this case on remand cannot be determined. However, the MATS rule took effect on April 15, 2015, and remains in effect until further action by the D.C. Circuit. Many of the announced retirements and emissions control installations undertaken to comply with MATS have already occurred.

CSAPR and MATS primarily impact coal-fired power plants, and therefore judicial decisions related to these rules do not directly affect our business. However, we believe that well-founded regulations protecting health and the environment could benefit our competitive position by better recognizing the value of our investments in clean power generation technology.

GHG Emissions

In January 2014, the EPA proposed New Source Performance Standards ("NSPS") for GHG emissions from new power plants, which are to be finalized within a reasonable period. In June 2014, the EPA proposed the Clean Power Plan which requires a reduction in GHG emissions from existing power plants of 30% from 2005 levels by 2030. According to the EPA, the Clean Power Plan is to be finalized by August 2015 with state plans to implement these guidelines to be finalized by August 2016 with a possible extension to 2017. The Clean Power Plan provides states flexibility in meeting the requirements including increasing energy efficiency measures, adding renewable generation and increasing dispatch of natural gas-fired generation. In June 2014, the EPA also proposed GHG NSPS provisions for modified and reconstructed sources (the "Modification/Reconstruction Rule"). In January 2015, the EPA announced that the GHG NSPS, the Modification/Reconstruction Rule and the Clean Power Plan would be finalized by summer 2015. We believe that our competitive position is enhanced by regulations that ensure all power plants take the necessary steps to reduce their pollutant emissions.

Demand Response Resources Under National Emissions Standard for Hazardous Air Pollutants ("NESHAP")

The FERC's Order No. 745 regarding compensation of demand response in the energy market was appealed to the D.C. Circuit. In May 2014, the D.C. Circuit issued an order vacating and remanding Order No. 745 on the basis that the FERC does not have jurisdiction to regulate demand response in the energy market. On January 15, 2015, the FERC and several other entities filed petitions for certiorari with the U.S. Supreme Court, asking for review of the D.C. Circuit's decision. Also, on October 20, 2014, the D.C. Circuit granted the FERC's request for a stay of the decision. In May 2015, the U.S. Supreme Court granted the petitions for certiorari and oral argument is expected to be heard in the fall of 2015. The stay will remain in place until final disposition by the U.S. Supreme Court.

On January 30, 2013, the EPA finalized amendments to the NESHAP for Reciprocating Internal Combustion Engines ("RICE"). The final rule creates an exemption from otherwise applicable air emission requirements for uncontrolled "emergency" diesel-fired backup generators to operate for up to 100 hours per year for "emergency demand response" ("the 100-Hour Rule") and up to 50 hours per year in certain non-emergency situations as part of a financial arrangement with another entity.

On May 1, 2015, the D.C. Circuit vacated the RICE NESHAP 100-Hour Rule and further modified its original ruling on July 21, 2015. The EPA has since filed motions seeking further action from the D.C. Circuit, and Calpine and the other petitioners are preparing responsive filings. Administrative and judicial challenges continue and we cannot predict the outcome of this litigation.

Clean Water Act - Waters of the United States

On June 29, 2015, the EPA published the "Clean Water Rule: Definition of "Waters of the United States", redefining and broadening the scope of Clean Water Act jurisdiction. The rule will become effective on August 28, 2015. We do not anticipate a significant impact to our business as a result of the Clean Water Rule.

California: GHG - Cap-and-Trade Regulation

California's AB 32 requires the state to reduce statewide GHG emissions to 1990 levels by 2020. To meet this benchmark, the CARB has promulgated a number of regulations, including the Cap-and-Trade Regulation and Mandatory Reporting Rule, which took effect on January 1, 2012. These regulations have since been amended by the CARB several times.

Under the Cap-and-Trade Regulation, the first compliance period for covered entities like Calpine began on January 1, 2013 and ended on December 31, 2014. The second and third compliance periods, wherein the program applies to a broader scope of entities, including transportation fuels and natural gas distribution, run through the end of 2017 and 2020, respectively. Covered entities must surrender compliance instruments, which include both allowances and offset credits, in an amount equivalent to their GHG emissions.

On January 1, 2014, the California Cap-and-Trade market was officially linked to the GHG Cap-and-Trade market in Quebec. The first joint GHG allowance auction occurred on November 25, 2014. Joint auctions of allowances issued by both jurisdictions, which can be used interchangeably, are held quarterly.

On May 22, 2014, the CARB approved its first update to the Climate Change Scoping Plan pursuant to AB 32. The updated scoping plan states that California is on track to meet its 2020 emissions target and makes recommendations for how the state can achieve the goal established by a 2005 executive order of reducing statewide GHG emissions to 80% below 1990 levels by 2050, including recommending the establishment of a mid-term emissions target for 2030. On April 29, 2015, California Governor Jerry Brown issued an executive order that establishes a new interim GHG reduction target of 40% below 1990 levels by 2030 and orders the CARB to update the Climate Change Scoping Plan to express the 2030 target in tons of GHG emissions.

Legislation has also been introduced that would enact both the 2050 and 2030 goals into law and authorize the CARB to continue relying in part upon market-based mechanisms, such as the Cap-and-Trade Regulation, to achieve those goals. The CARB is also considering possible reliance upon the Cap-and-Trade Regulation as a component of any state plan that would be required pursuant to the EPA-proposed Clean Power Plan.

On April 13, 2015, Ontario's Premier Kathleen Wynne announced that the Canadian province will be developing a Cap-and-Trade program and intends to join the linked California-Quebec market. Several rulemaking steps would need to occur before an Ontario Cap-and-Trade system could be linked with the California program, including that the California governor would need to make findings regarding the equivalence and enforceability of Ontario's GHG emission reduction program and the CARB would need to adopt an amendment to the Cap-and-Trade Regulation.

Overall, we support AB 32 and expect the net impact of the Cap-and-Trade Regulation to be beneficial to Calpine. We also believe we are well positioned to comply with the Cap-and-Trade Regulation.

California RPS

California's current RPS requires retail power providers to generate or procure 33% of the power they sell to retail customers from renewable resources by 2020, with intermediate targets leading up to 2020. Under California's RPS, 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 certain 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 our role as an energy service provider, we are subject to the RPS requirements and continue to meet our compliance obligations. The RPS also provides opportunities to market the output from the Geysers. The net impact of the RPS has been to increase the need for flexible thermal generation but it also has depressed wholesale electricity prices. The California Legislature is currently considering increasing the RPS to 50% by 2030. It is unclear whether behind-the-meter solar, which generally is not used for RPS compliance currently, would count towards a 50% RPS.

RESULTS OF OPERATIONS FOR THE THREE MONTHS ENDED JUNE 30, 2015 AND 2014

Below are our results of operations for the three months ended June 30, 2015 as compared to the same period in 2014 (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.

	2015	2014	Change	% Change
Operating revenues:				
Commodity revenue	$ 1,407	$ 1,766	$ (359)	(20)
Mark-to-market gain	31	169	(138)	(82)
Other revenue	4	4	—	—
Operating revenues	1,442	1,939	(497)	(26)
Operating expenses:				
Fuel and purchased energy expense:				
Commodity expense	734	1,106	372	34
Mark-to-market loss	32	28	(4)	(14)
Fuel and purchased energy expense	766	1,134	368	32
Plant operating expense	272	274	2	1
Depreciation and amortization expense	160	147	(13)	(9)
Sales, general and other administrative expense	30	38	8	21
Other operating expenses	20	21	1	5
Total operating expenses	1,248	1,614	366	23
(Income) from unconsolidated investments in power plants	(7)	(4)	3	75
Income from operations	201	329	(128)	(39)
Interest expense	158	169	11	7
Interest (income)	(1)	(2)	(1)	(50)
Debt modification costs	13	—	(13)	#
Other (income) expense, net	5	6	1	17
Income before income taxes	26	156	(130)	(83)
Income tax expense	5	15	10	67
Net income	21	141	(120)	(85)
Net income attributable to the noncontrolling interest	(2)	(2)	—	—
Net income attributable to Calpine	$ 19	$ 139	$ (120)	(86)

	2015	2014	Change	% Change
Operating Performance Metrics:				
MWh generated (in thousands)[(1)]	26,954	23,085	3,869	17
Average availability	86.0%	88.1%	(2.1)%	(2)
Average total MW in operation[(1)]	25,757	28,368	(2,611)	(9)
Average capacity factor, excluding peakers	53.4%	41.7%	11.7 %	28
Steam Adjusted Heat Rate	7,329	7,433	104	1

\# Variance of 100% or greater

(1)

Represents generation and capacity from power plants that we both consolidate and operate and excludes Greenfield LP, Whitby, Freeport Energy Center, 21.5% of Hidalgo Energy Center and 25% each of Freestone Energy Center and Russell City Energy Center.

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 of 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 $13 million for the three months ended June 30, 2015, compared to the same period in 2014, primarily due to:

- higher generation across all segments during the second quarter of 2015 resulting from lower natural gas prices in the East and Texas and stronger market conditions in June 2015 in the West resulting from warmer weather and a decrease in hydroelectric generation in the Pacific Northwest; and
- higher contribution from hedges across all of our segments; partially offset by
- the net impact of our portfolio management activities, including the sale of six power plants with a total capacity of 3,498 MW in our East segment in July 2014, the acquisition of our Fore River Energy Center in November 2014, the commencement of commercial operations at our Garrison Energy Center in June 2015 and the completion of the expansions of our Deer Park and Channel Energy Centers in June 2014; and
- lower regulatory capacity revenue in PJM.

Generation increased 17% primarily due to the market conditions described above. Our average total MW in operation decreased by 2,611 MW, or 9%, primarily due to the aforementioned changes in our power plant portfolio.

Mark-to-market gain/loss on our derivative hedge position had an unfavorable variance of $142 million for the three months ended June 30, 2015, compared to the same period in 2014, primarily driven by a decrease in forward ERCOT power prices during the three months ended June 30, 2014.

Plant operating expense decreased by $2 million for the three months ended June 30, 2015, compared to the same period in 2014. Our normal, recurring plant operating expense, after excluding a decrease of $9 million attributable to power plant portfolio changes detailed above, decreased by $5 million during the second quarter of 2015 compared to the second quarter of 2014. The overall decrease was partially offset by a net increase of $12 million related to an increase in major maintenance expense resulting from our plant outage schedule and costs from scrap parts related to outages, net of a decrease in stock-based compensation expense and other miscellaneous costs.

Depreciation and amortization expense increased by $13 million for the three months ended June 30, 2015, compared to the same period in 2014, primarily due to asset retirement obligation costs associated with the expiration of the lease for the Greenleaf 1 and 2 Power Plants.

Sales, general and other administrative expenses decreased by $8 million for the three months ended June 30, 2015, compared to the same period in 2014, primarily due to a decrease in the fair value of stock-based compensation awards.

Interest expense decreased by $11 million for the three months ended June 30, 2015, compared to the same period in 2014, primarily due to a decrease in our annual effective interest rate on our consolidated debt, excluding the impacts of capitalized interest and mark-to-market gains (losses) on interest rate swaps, to 5.5% for the three months ended June 30, 2015, from 6.1% for the three months ended June 30, 2014. The issuance of our Senior Unsecured Notes in July 2014 and February 2015 and our 2022 First Lien Term Loan in May 2015 allowed us to reduce our overall cost of debt by replacing a portion of our First Lien Notes and all of our 2018 First Lien Term Loans with debt carrying lower interest rates.

Debt modification costs for the three months ended June 30, 2015 consisted of $13 million in costs related to the issuance of our 2022 First Lien Term Loan in May 2015.

During the three months ended June 30, 2015, we recorded income tax expense of $5 million compared to $15 million for the same period in 2014. The favorable period-over-period change primarily resulted from a decrease in income tax expense associated with a decrease in our pre-tax income during the three months ended June 30, 2015 compared to the same period in 2014 partially offset by an increase resulting from tax law changes.

RESULTS OF OPERATIONS FOR THE SIX MONTHS ENDED JUNE 30, 2015 AND 2014

Below are our results of operations for the six months ended June 30, 2015 as compared to the same period in 2014 (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.

	2015	2014	Change	% Change
Operating revenues:				
Commodity revenue	$ 3,045	$ 3,814	$ (769)	(20)
Mark-to-market gain	34	83	(49)	(59)
Other revenue	9	7	2	29
Operating revenues	3,088	3,904	(816)	(21)
Operating expenses:				
Fuel and purchased energy expense:				
Commodity expense	1,811	2,476	665	27
Mark-to-market (gain) loss	(35)	15	50	#
Fuel and purchased energy expense	1,776	2,491	715	29
Plant operating expense	532	539	7	1
Depreciation and amortization expense	318	300	(18)	(6)
Sales, general and other administrative expense	67	71	4	6
Other operating expenses	40	43	3	7
Total operating expenses	2,733	3,444	711	21
(Income) from unconsolidated investments in power plants	(12)	(13)	(1)	(8)
Income from operations	367	473	(106)	(22)
Interest expense	312	335	23	7
Interest (income)	(2)	(3)	(1)	(33)
Debt modification and extinguishment costs	32	1	(31)	#
Other (income) expense, net	7	16	9	56
Income before income taxes	18	124	(106)	(85)
Income tax expense (benefit)	4	(4)	(8)	#
Net income	14	128	(114)	(89)
Net income attributable to the noncontrolling interest	(5)	(6)	1	17
Net income attributable to Calpine	$ 9	$ 122	$ (113)	(93)

	2015	2014	Change	% Change
Operating Performance Metrics:				
MWh generated (in thousands)(1)	52,521	46,062	6,459	14
Average availability	87.7%	88.3%	(0.6)%	(1)
Average total MW in operation(1)	25,763	28,031	(2,268)	(8)
Average capacity factor, excluding peakers	52.7%	42.4%	10.3 %	24
Steam Adjusted Heat Rate	7,296	7,393	97	1

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Variance of 100% or greater

(1)

Represents generation and capacity from power plants that we both consolidate and operate and excludes Greenfield LP, Whitby, Freeport Energy Center, 21.5% of Hidalgo Energy Center and 25% each of Freestone Energy Center and Russell City Energy Center.

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 of 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 $104 million for the six months ended June 30, 2015, compared to the same period in 2014, primarily due to:

- a significant decrease in power and natural gas prices in our East segment in the first quarter of 2015 compared to the prior year period, given the unusually high price levels experienced during the polar vortex events in the first quarter of 2014;
- the net impact of our portfolio management activities, including the sale of six power plants with a total capacity of 3,498 MW in our East segment in July 2014, the acquisition of our Guadalupe and Fore River Energy Centers in February and November 2014, respectively, the commencement of commercial operations at our Garrison Energy Center in June 2015 and the completion of the expansions of our Deer Park and Channel Energy Centers in June 2014; and
- lower regulatory capacity revenue in PJM; partially offset by
- higher contribution from hedges which more than offset lower on-peak Spark Spreads across all of our segments, excluding the impact of the polar vortex events experienced during the first quarter of 2014; and
- higher generation in Texas resulting from lower natural gas prices, which drove lower systemwide coal-fired generation during the first half of 2015.

Generation increased 14% primarily due to higher generation in Texas due to the factors described above. Our average total MW in operation decreased by 2,268 MW, or 8%, primarily due to the aforementioned changes in our power plant portfolio.

Plant operating expense decreased by $7 million for the six months ended June 30, 2015, compared to the same period in 2014. Our normal, recurring plant operating expense, after excluding a decrease of $17 million attributable to power plant portfolio changes detailed above, decreased by $1 million during the first half of 2015 compared to the same period in 2014. The overall decrease was partially offset by a net increase of $11 million related to an increase in major maintenance expense resulting from our plant outage schedule and costs from scrap parts related to outages, net of a decrease in stock-based compensation expense and other miscellaneous costs.

Depreciation and amortization expense increased by $18 million for the six months ended June 30, 2015, compared to the same period in 2014, primarily due to asset retirement obligation costs associated with the expiration of the lease for the Greenleaf 1 and 2 Power Plants.

Sales, general and other administrative expenses decreased by $4 million for the six months ended June 30, 2015, compared to the same period in 2014, primarily due to a decrease in the fair value of stock-based compensation awards.

Interest expense decreased by $23 million for the six months ended June 30, 2015, compared to the same period in 2014, primarily due to a decrease in our annual effective interest rate on our consolidated debt, excluding the impacts of capitalized interest and mark-to-market gains (losses) on interest rate swaps, to 5.5% for the six months ended June 30, 2015, from 6.1% for the six months ended June 30, 2014. The issuance of our Senior Unsecured Notes in July 2014 and February 2015 and our 2022 First Lien Term Loan in May 2015 allowed us to reduce our overall cost of debt by replacing a portion of our First Lien Notes and all of our 2018 First Lien Term Loans with debt carrying lower interest rates.

Debt modification and extinguishment costs for the six months ended June 30, 2015, consisted of $19 million in connection with the repurchase of approximately $147 million of our 2023 First Lien Notes, which is comprised of $18 million of prepayment penalties and $1 million associated with the write-off of deferred financing costs, and $13 million in costs related to the issuance of our 2022 First Lien Term Loan in May 2015.

During the six months ended June 30, 2015, we recorded income tax expense of $4 million compared to an income tax benefit of $4 million for the same period in 2014. The unfavorable period-over-period change primarily resulted from a one-time tax benefit recorded during the first quarter of 2014 associated with the reorganization of certain Calpine subsidiaries as well as an increase resulting from tax law changes, partially offset by a decrease in tax expense due to a decrease in pre-tax income during the six months ended June 30, 2015 compared to the same period in 2014.

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, environmental compliance expense, and realized settlements from our marketing, hedging, optimization and trading activities, but excludes 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 12 of the Notes to Consolidated Condensed Financial Statements for a reconciliation of Commodity Margin to income from operations by segment.

Commodity Margin by Segment for the Three Months Ended June 30, 2015 and 2014

The following tables show our Commodity Margin and related operating performance metrics by segment for the three months ended June 30, 2015 and 2014 (exclusive of the noncontrolling interest). In the comparative tables below, favorable variances are shown without brackets while unfavorable variances are shown with brackets. The MWh generated by segment below represent generation from power plants that we both consolidate and operate.

West:	2015	2014	Change	% Change
Commodity Margin (in millions)	$ 240	$ 228	$ 12	5
Commodity Margin per MWh generated	$ 28.47	$ 33.68	$ (5.21)	(15)
MWh generated (in thousands)	8,430	6,770	1,660	25
Average availability	82.8%	91.6%	(8.8)%	(10)
Average total MW in operation	7,524	7,524	—	—
Average capacity factor, excluding peakers	54.7%	44.0%	10.7 %	24
Steam Adjusted Heat Rate	7,325	7,377	52	1

West — Commodity Margin in our West segment increased by $12 million, or 5%, for the three months ended June 30, 2015 compared to the three months ended June 30, 2014, primarily due to higher contribution from hedges and increased generation due to stronger market conditions in June 2015, despite weaker market conditions in April and May 2015, resulting from warmer weather and a decrease in hydroelectric generation in the Pacific Northwest. In addition, Commodity Margin increased due to higher REC revenues associated with our Geysers Assets resulting from more favorable REC pricing in 2015. Average availability decreased 10% due to an increase in planned outages during the second quarter of 2015 compared to the same period in 2014.

Texas:	2015	2014	Change	% Change
Commodity Margin (in millions)	$ 170	$ 177	$ (7)	(4)
Commodity Margin per MWh generated	$ 15.19	$ 18.65	$ (3.46)	(19)
MWh generated (in thousands)	11,194	9,489	1,705	18
Average availability	87.7%	90.8%	(3.1)%	(3)
Average total MW in operation	9,191	8,885	306	3
Average capacity factor, excluding peakers	55.8%	48.9%	6.9 %	14

Steam Adjusted Heat Rate	7,078	7,282	204	3

Texas — Commodity Margin in our Texas segment decreased by $7 million, or 4%, for the three months ended June 30, 2015 compared to the three months ended June 30, 2014, due to lower on-peak Spark Spreads resulting from lower natural gas prices, the impact of which was partially offset by an 18% increase in generation also resulting from lower natural gas prices that drove lower systemwide coal-fired generation during the second quarter of 2015. The decrease in Commodity Margin was also partially offset by higher contribution from hedges and the expansions of our Deer Park and Channel Energy Centers which were completed in June 2014. Our average total MW in operation increased 306 MW, or 3%, primarily due to the expansions of our Deer Park and Channel Energy Centers.

East:	2015	2014	Change	% Change
Commodity Margin (in millions)	$ 247	$ 227	$ 20	9
Commodity Margin per MWh generated	$ 33.70	$ 33.26	$ 0.44	1
MWh generated (in thousands)	7,330	6,826	504	7
Average availability	87.0%	83.6%	3.4%	4
Average total MW in operation	9,042	11,959	(2,917)	(24)
Average capacity factor, excluding peakers	48.7%	32.9%	15.8%	48
Steam Adjusted Heat Rate	7,738	7,694	(44)	(1)

East — Commodity Margin in our East segment increased by $62 million for the three months ended June 30, 2015 compared to the three months ended June 30, 2014, after excluding a decrease of $42 million resulting from the sale of six power plants with a total capacity of 3,498 MW on July 3, 2014. The increase in Commodity Margin was primarily due to the acquisition of our 731 MW Fore River Energy Center in November 2014, the commencement of commercial operations at our 309 MW Garrison Energy Center in June 2015 partially offset by the retirements of our 34 MW Cedar Energy Center, 60 MW Missouri Avenue Energy Center and 77 MW Middle Energy Center in May 2015, higher Spark Spreads on our open position driven by lower natural gas prices, which also drove a 7% increase in generation, and higher contribution from hedges during the second quarter of 2015 compared to the second quarter of 2014. The increase in Commodity Margin was partially offset by lower regulatory capacity revenues in PJM during the three months ended June 30, 2015 compared to the same period in 2014. Average Total MW in Operation decreased by 2,917 MW, or 24%, primarily due to the aforementioned power plant portfolio changes.

Commodity Margin by Segment for the Six Months Ended June 30, 2015 and 2014

The following tables show our Commodity Margin and related operating performance metrics by segment for the six months ended June 30, 2015 and 2014 (exclusive of the noncontrolling interest). In the comparative tables below, favorable variances are shown without brackets while unfavorable variances are shown with brackets. The MWh generated by segment below represent generation from power plants that we both consolidate and operate.

West:	2015	2014	Change	% Change
Commodity Margin (in millions)	$ 458	$ 430	$ 28	7
Commodity Margin per MWh generated	$ 29.20	$ 27.56	$ 1.64	6
MWh generated (in thousands)	15,683	15,601	82	1
Average availability	85.6%	90.3%	(4.7)%	(5)
Average total MW in operation	7,524	7,524	—	—
Average capacity factor, excluding peakers	51.2%	51.1%	0.1 %	—
Steam Adjusted Heat Rate	7,314	7,301	(13)	—

West — Commodity Margin in our West segment increased by $28 million, or 7%, for the six months ended June 30, 2015 compared to the six months ended June 30, 2014, primarily due to higher contribution from hedges and higher REC revenues associated with our Geysers Assets resulting from more favorable REC pricing in 2015. The increase in Commodity Margin was partially offset by lower on-peak Spark Spreads resulting from lower natural gas prices for the six months ended June 30, 2015 compared to the six months ended June 30, 2014. Average availability decreased 5% due to an increase in planned outages during the second quarter of 2015 compared to the same period in 2014.

Texas:	2015	2014	Change	% Change
Commodity Margin (in millions)	$ 319	$ 298	$ 21	7
Commodity Margin per MWh generated	$ 14.03	$ 18.21	$ (4.18)	(23)
MWh generated (in thousands)	22,738	16,366	6,372	39
Average availability	87.9%	86.9%	1.0%	1
Average total MW in operation	9,191	8,521	670	8
Average capacity factor, excluding peakers	57.0%	44.2%	12.8%	29
Steam Adjusted Heat Rate	7,087	7,227	140	2

Texas — Commodity Margin in our Texas segment increased by $21 million, or 7%, for the six months ended June 30, 2015 compared to the six months ended June 30, 2014, due to the acquisition of our 1,000 MW Guadalupe Energy Center on February 26, 2014, the expansions of our Deer Park and Channel Energy Centers which were completed in June 2014, higher contribution from hedges and a 39% increase in generation resulting from lower natural gas prices, which drove lower systemwide coal-fired generation during the first half of 2015. The increase in Commodity Margin was partially offset by lower on-peak Spark Spreads also resulting from lower natural gas prices during the first half of 2015 compared to the first half of 2014. Our average total MW in operation increased 670 MW, or 8%, primarily resulting from the acquisition of Guadalupe Energy Center and the expansions of our Deer Park and Channel Energy Centers.

East:	2015	2014	Change	% Change
Commodity Margin (in millions)	$ 415	$ 549	$ (134)	(24)
Commodity Margin per MWh generated	$ 29.43	$ 38.95	$ (9.52)	(24)
MWh generated (in thousands)	14,100	14,095	5	—
Average availability	89.3%	88.0%	1.3%	1
Average total MW in operation	9,048	11,986	(2,938)	(25)
Average capacity factor, excluding peakers	48.3%	34.1%	14.2%	42
Steam Adjusted Heat Rate	7,629	7,678	49	1

East — Commodity Margin in our East segment decreased by $53 million for the six months ended June 30, 2015 compared to the six months ended June 30, 2014, after excluding a decrease of $81 million resulting from the sale of six power plants with a total capacity of 3,498 MW on July 3, 2014. The decrease in Commodity Margin was primarily due to a significant decrease in power and natural gas prices in the first quarter of 2015 compared to the prior year period, given the unusually high price levels experienced during the polar vortex events in the first quarter of 2014, as well as lower regulatory capacity revenues in PJM. The decrease in Commodity Margin was partially offset by the acquisition of our 731 MW Fore River Energy Center in November 2014 and the commencement of commercial operations at our 309 MW Garrison Energy Center in June 2015, partially offset by the retirements of our 34 MW Cedar Energy Center, 60 MW Missouri Avenue Energy Center and 77 MW Middle Energy Center in May 2015, and higher contribution from hedges during the first half of 2015 compared to the first half of 2014. Average total MW in operation decreased 2,938 MW, or 25%, primarily due to the aforementioned power plant portfolio changes.

Adjusted EBITDA

We define Adjusted EBITDA, a non-GAAP financial measure, 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. 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 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 mark-to-market gains or losses from accounting for derivatives, adjustments to exclude the Adjusted EBITDA related to the noncontrolling interest, 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, modification or extinguishment of debt, non-cash GAAP-related adjustments to levelize revenues from tolling agreements and any extraordinary, unusual or non-recurring items plus 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.

During the third quarter of 2014, we altered the composition of our geographic segments to combine our former North and Southeast segments into one segment which was renamed the East segment. This change reflects the manner in which our geographic information is presented internally to our chief operating decision maker following the sale of six power plants in July 2014 that composed a substantial portion of our former Southeast segment. Thus, beginning in the third quarter of 2014, our reportable segments are West (including geothermal), Texas and East (including Canada). The tables below have been revised to present our segments on this basis for all periods.

The tables below provide a reconciliation of Adjusted EBITDA to our income from operations on a segment basis and to net income attributable to Calpine on a consolidated basis for the periods indicated (in millions).

	Three Months Ended June 30, 2015				
	West	Texas	East	Consolidation and Elimination	Total
Net income attributable to Calpine					$ 19
Net income attributable to the noncontrolling interest					2
Income tax expense					5
Debt modification costs and other (income) expense, net					18
Interest expense, net of interest income					157
Income from operations	$ 25	$ 31	$ 145	$ —	$ 201
Add:					
Adjustments to reconcile income from operations to Adjusted EBITDA:					
Depreciation and amortization expense, excluding deferred financing costs(1)	65	49	45	—	159
Major maintenance expense	41	24	25	—	90
Operating lease expense	1	—	7	—	8
Mark-to-market (gain) loss on commodity derivative activity	40	(3)	(36)	—	1
Adjustments to reflect Adjusted EBITDA from unconsolidated investments and exclude the noncontrolling interest(2)	(4)	—	8	—	4
Stock-based compensation expense	1	—	—	—	1
Loss on dispositions of assets	—	2	—	—	2
Acquired contract amortization	—	—	3	—	3
Other	(18)	1	5	—	(12)
Total Adjusted EBITDA	$ 151	$ 104	$ 202	$ —	$ 457

	Three Months Ended June 30, 2014				
	West	Texas	East[3]	Consolidation and Elimination	Total
Net income attributable to Calpine					$ 139
Net income attributable to the noncontrolling interest					2
Income tax expense					15
Other (income) expense, net					6
Interest expense, net of interest income					167
Income from operations	$ 74	$ 211	$ 43	$ 1	$ 329
Add:					
Adjustments to reconcile income from operations to Adjusted EBITDA:					
Depreciation and amortization expense, excluding deferred financing costs[1]	58	48	40	—	146
Major maintenance expense	18	20	34	—	72
Operating lease expense	2	—	6	—	8
Mark-to-market (gain) loss on commodity derivative activity	10	(177)	26	—	(141)
Adjustments to reflect Adjusted EBITDA from unconsolidated investments and exclude the noncontrolling interest[2]	(2)	—	8	—	6
Stock-based compensation expense	2	6	4	—	12
Loss on dispositions of assets	1	—	—	—	1
Acquired contract amortization	—	—	3	—	3
Other	(23)	1	—	(1)	(23)
Total Adjusted EBITDA	$ 140	$ 109	$ 164	$ —	$ 413

	Six Months Ended June 30, 2015				
	West	Texas	East	Consolidation and Elimination	Total
Net income attributable to Calpine					$ 9
Net income attributable to the noncontrolling interest					5
Income tax expense					4
Debt modification and extinguishment costs and other (income) expense, net					39
Interest expense, net of interest income					310
Income from operations	$ 169	$ 64	$ 134	$ —	$ 367
Add:					
Adjustments to reconcile income from operations to Adjusted EBITDA:					
Depreciation and amortization expense, excluding deferred financing costs[1]	130	99	87	—	316
Major maintenance expense	66	55	47	—	168
Operating lease expense	4	—	13	—	17
Mark-to-market (gain) loss on commodity derivative activity	(47)	(36)	14	—	(69)
Adjustments to reflect Adjusted EBITDA from unconsolidated investments and exclude the noncontrolling interest[2]	(7)	—	16	—	9
Stock-based compensation expense	5	5	2	—	12
Loss on dispositions of assets	—	2	1	—	3
Acquired contract amortization	—	—	7	—	7
Other	(42)	1	6	—	(35)
Total Adjusted EBITDA	$ 278	$ 190	$ 327	$ —	$ 795

	Six Months Ended June 30, 2014				
	West	Texas	East[3]	Consolidation and Elimination	Total
Net income attributable to Calpine					$ 122
Net income attributable to the noncontrolling interest					6
Income tax benefit					(4)
Debt extinguishment costs and other (income) expense, net					17
Interest expense, net of interest income					332
Income from operations	$ 118	$ 140	$ 214	$ 1	$ 473
Add:					
Adjustments to reconcile income from operations to Adjusted EBITDA:					
Depreciation and amortization expense, excluding deferred financing costs[1]	116	90	91	—	297
Major maintenance expense	46	57	50	—	153
Operating lease expense	4	—	13	—	17
Mark-to-market (gain) loss on commodity derivative activity	14	(124)	42	—	(68)
Adjustments to reflect Adjusted EBITDA from unconsolidated investments and exclude the noncontrolling interest[2]	(6)	—	15	—	9
Stock-based compensation expense	6	9	7	—	22
Loss on dispositions of assets	1	—	—	—	1
Acquired contract amortization	—	—	7	—	7
Other	(46)	1	(6)	(1)	(52)
Total Adjusted EBITDA	$ 253	$ 173	$ 433	$ —	$ 859

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

(2) Adjustments to reflect Adjusted EBITDA from unconsolidated investments include (gain) loss on mark-to-market activity of nil for the three and six months ended June 30, 2015 and 2014.

(3) Adjusted EBITDA related to the six power plants sold in our East segment on July 3, 2014 was $23 million and $43 million for the three and six months ended June 30, 2014, respectively.

LIQUIDITY AND CAPITAL RESOURCES

We maintain a strong focus on liquidity. We manage our liquidity to help provide access to sufficient funding to meet our business needs and financial obligations throughout business cycles.

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

The following table provides a summary of our liquidity position at June 30, 2015 and December 31, 2014 (in millions):

	June 30, 2015	December 31, 2014
Cash and cash equivalents, corporate[1]	$ 345	$ 460
Cash and cash equivalents, non-corporate	77	257
Total cash and cash equivalents	422	717
Restricted cash	210	244
Corporate Revolving Facility availability	1,321	1,277
CDHI letter of credit facility availability	56	86
Total current liquidity availability	$ 2,009	$ 2,324

(1) Includes $53 million and $47 million of margin deposits posted with us by our counterparties at June 30, 2015 and December 31, 2014, respectively.

Our principal source for future liquidity is cash flows generated from our operations. 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. See "Cash Flow Activities" below for a further discussion of our change in cash and cash equivalents.

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.

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 funds that are not FDIC insured. We place our cash, cash equivalents and restricted cash in what we believe to be creditworthy financial institutions.

We have never paid cash dividends on our common stock. Future cash dividends, if any, may be authorized 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 July 15, 2015, an increase of $1/MMBtu in natural gas prices would result in an increase of collateral required by approximately $249 million. If natural gas prices decreased by $1/MMBtu, we estimate that our collateral requirements would decrease by approximately $246 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 and the regional characteristics of each power market. We estimate that at July 15, 2015, an increase of 500 Btu/KWh in the Market Heat Rate would result in an increase in collateral required by approximately $60 million. If Market Heat Rates were to fall at a similar rate, we estimate that our collateral required would decrease by $58 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 are executed.

In order to effectively manage our future Commodity Margin, we have economically hedged a portion of our generation and natural gas portfolio mostly through power and natural gas forward physical and financial transactions; however, we currently remain susceptible to significant price movements for 2015 and beyond. In addition to the price of natural gas, our Commodity Margin is highly dependent on other factors such as:

- the level of Market Heat Rates;
- our continued ability to successfully hedge our Commodity Margin;
- changes in U.S. macroeconomic conditions;
- maintaining acceptable availability levels for our fleet;
- the impact of current and pending environmental regulations in the markets in which we participate;
- improving the efficiency and profitability of our operations;
- increasing future contractual cash flows; and
- our significant counterparties performing under their contracts with us.

Additionally, scheduled outages related to the life cycle of our power plant fleet in addition to unscheduled outages may result in maintenance expenditures that are disproportionate in differing periods. In order to manage such liquidity requirements, we maintain additional liquidity availability in the form of our Corporate Revolving Facility (noted in the table above), letters of credit and the ability to issue first priority liens for collateral support. It is difficult to predict future developments and the amount of credit support that we may need to provide should such conditions occur, we experience another economic recession or energy commodity prices increase significantly.

Letter of Credit Facilities

The table below represents amounts issued under our letter of credit facilities at June 30, 2015 and December 31, 2014 (in millions):

	June 30, 2015	December 31, 2014
Corporate Revolving Facility(1)	$ 179	$ 223
CDHI	244	214
Various project financing facilities	219	207
Total	$ 642	$ 644

(1) The Corporate Revolving Facility represents our primary revolving facility.

Capital Management

In connection with our goals of enhancing long-term shareholder value, we have completed, made progress toward completing or initiated certain key capital management transactions during 2015, as further described below.

Share Repurchase Program

In 2015, through the filing of this Report, we have repurchased a total of 23.3 million shares of our common stock for approximately $475 million at an average price of $20.42 per share.

2024 Senior Unsecured Notes

In February 2015, we issued $650 million in aggregate principal amount of 5.5% senior unsecured notes due 2024 in a public offering and used the net proceeds to replenish cash on hand used for the acquisition of Fore River Energy Center in the fourth quarter of 2014, to repurchase approximately $147 million of our 2023 First Lien Notes and for general corporate purposes.

See Note 4 of the Notes to Consolidated Condensed Financial Statements for a further description of our 2024 Senior Unsecured Notes.

2022 First Lien Term Loan

In May 2015, we repaid our 2018 First Lien Term Loans with the proceeds from the 2022 First Lien Term Loan which extended the maturity and reduced the interest rate on approximately $1.6 billion of corporate debt. See Note 4 of the Notes to Consolidated Condensed Financial Statements for a further description of our 2022 First Lien Term Loan.

Managing and Growing our Portfolio

Our goal is to continue to grow our presence in core markets with an emphasis on acquisitions, expansions or modernizations 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 actively seek to divest non-core assets where we can find opportunities to do so accretively. In addition, we believe that modernizations 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, modernizations and strategic asset sales are discussed below.

Garrison Energy Center — Our Garrison Energy Center commenced commercial operations in June 2015, bringing online approximately 309 MW of combined-cycle, natural gas-fired capacity. The power plant features one combustion turbine, one heat recovery steam generator and one steam turbine, and is expected to be dual-fuel capable by this winter. We are in the early stages of development of a second phase of the Garrison Energy Center.

York 2 Energy Center — York 2 Energy Center is a 760 MW dual fuel combined-cycle project that will be co-located with our York Energy Center in Peach Bottom Township, Pennsylvania. Once complete, the power plant will feature two combustion turbines, two heat recovery steam generators and one steam turbine. The project's capacity cleared PJM's 2017/2018 base residual auction. The project is now under construction, and we expect COD during the second quarter of 2017. PJM has completed the feasibility study for increasing York 2 Energy Center's planned capacity by 70 MW, and the queue position has entered the system impact study stage.

Guadalupe Peaking Energy Center — In April 2015, we executed an agreement with Guadalupe Valley Electric Cooperative ("GVEC") that will facilitate the construction of a 418 MW natural gas-fired peaking power plant to be co-located with our Guadalupe Energy Center. Under the terms of the agreement, construction of the Guadalupe Peaking Energy Center ("GPEC") may commence at our discretion, so long as the power plant reaches COD between the dates of June 1, 2017, and June 1, 2019. When the power plant begins commercial operation, GVEC will purchase a 50% ownership interest in GPEC. Once built, GPEC will feature two fast-ramping combustion turbines capable of responding to peaks in power demand. This project represents a mutually beneficial response to our customer's desire to have direct access to peaking generation resources, as it leverages the benefits of our existing site and development rights and our construction and operating expertise, as well as our customer's ability to fund its investment at attractive rates, all while affording us the flexibility of timing the plant's construction in response to market pricing signals.

Mankato Power Plant Expansion — By order dated February 5, 2015, the Minnesota Public Utilities Commission concluded a competitive resource acquisition proceeding and selected a 345 MW expansion of our Mankato Power Plant, authorizing execution of a 20-year PPA between Calpine and Xcel Energy. The PPA was executed in April 2015 and remains subject to approval by the North Dakota Public Service Commission. Commercial operation of the expanded capacity may commence as early as the summer of 2018, subject to requisite regulatory approvals and applicable contract conditions.

PJM and ISO-NE Development Opportunities — We are currently evaluating opportunities to develop additional projects in the PJM and ISO-NE market areas that feature cost advantages such as existing infrastructure and favorable transmission queue positions. These projects are continuing to advance entitlements (such as permits, zoning and transmission) for their potential future development when economical.

Osprey Energy Center — We executed an asset sale agreement during the fourth quarter of 2014 for the sale of our Osprey Energy Center to Duke Energy Florida, Inc. for approximately $166 million, excluding working capital and other adjustments. In accordance with the asset sale agreement, the sale will be consummated in January 2017 upon the conclusion of a 27-month PPA. In July 2015, the transaction was approved by the FERC, and the Florida Public Service Commission voted to approve the Florida Commission Hearing Officer's Recommended Order approving the transaction. This sale represents a strategic disposition of a power plant in a wholesale power market dominated by regulated utilities.

Turbine Modernization — We continue to move forward with our turbine modernization program. Through June 30, 2015, we have completed the upgrade of thirteen Siemens and eight GE turbines totaling approximately 210 MW and have committed to upgrade three additional turbines. In addition, we have begun a program to update our dual-fueled turbines at certain of our power plants in our East segment.

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 in 2015 is as follows:

Retail Acquisition

- In July 2015, we entered into an agreement to purchase Champion Energy for approximately $240 million, excluding working capital adjustments. Champion Energy, a leading retail electric provider, is expected to serve approximately 22 million MWh of commercial, industrial and residential customer load in 2015, concentrated in Texas, PJM and the Northeast U.S. where Calpine has a substantial power generation presence. The addition of this well-established retail sales organization is expected to provide us an important outlet for directly reaching a much greater portion of the load we serve.

West

- We entered into a new three-year PPA with Marin Clean Energy to provide up to 65 MW of power from our Delta Energy Center and other northern California power plants commencing in April 2015 and extending through December 2017.
- Our ten-year PPA with Southern California Edison for 225 MW of capacity and renewable energy from our Geysers Assets commencing in June 2017 was approved by the CPUC in the first quarter of 2015.
- We entered into a new ten-year PPA with Southern California Edison for 50 MW of capacity and renewable energy from our Geysers Assets commencing in January 2018. The PPA remains subject to approval by the CPUC.

Texas

- We entered into a new three-year PPA with Brazos Electric Power Cooperative to provide 300 MW of power from our Texas power plant fleet commencing in January 2016.
- We entered into a new three-year PPA with Pedernales Electric Cooperative to provide approximately 140 MW of power from our Texas power plant fleet commencing in January 2017.
- We entered into a new two-year PPA with Guadalupe Valley Electric Cooperative to provide approximately 270 MW of power from our Texas power plant fleet commencing in June 2017. The execution of this PPA will facilitate the construction of a 418 MW natural gas-fired peaking power plant to be co-located with our Guadalupe Energy Center.

East

- We entered into a new 20-year PPA with Xcel Energy to provide up to 345 MW of capacity and energy from our Mankato Power Plant expansion when commercial operations commence and transmission-related upgrades have been completed.

NOLs

We have significant NOLs that will provide future tax deductions when we generate sufficient taxable income during the applicable carryover periods. At December 31, 2014, our consolidated federal NOLs totaled approximately $6.9 billion.

Cash Flow Activities

The following table summarizes our cash flow activities for the six months ended June 30, 2015 and 2014 (in millions):

	2015	2014
Beginning cash and cash equivalents	$ 717	$ 941
Net cash provided by (used in):		
Operating activities	19	349
Investing activities	(246)	(900)
Financing activities	(68)	52

Net decrease in cash and cash equivalents	(295)	(499)
Ending cash and cash equivalents	$ 422	$ 442

Net Cash Provided By Operating Activities

Cash provided by operating activities for the six months ended June 30, 2015, was $19 million compared to cash provided by operating activities of $349 million for the six months ended June 30, 2014. The decrease was primarily due to:

- *Income from operations* — Income from operations, adjusted for non-cash items, decreased by $85 million for the six months ended June 30, 2015, compared to the six months ended June 30, 2014. Non-cash items consist primarily of depreciation and amortization, income from unconsolidated investments in power plants and mark-to-market activity. The decrease in income from operations was primarily driven by a $104 million decrease in Commodity revenue, net of Commodity expense, primarily from our East segment due to higher power and natural gas prices during first quarter of 2014 resulting from extreme weather driven by the polar vortex, lower regulatory capacity revenue in PJM and portfolio changes, partially offset by higher contribution from hedges and higher generation in Texas resulting from lower natural gas prices for the six months ended June 30, 2015, compared to the six months ended June 30, 2014. See "Results of Operations for the Six Months Ended June 30, 2015 and 2014" above for further discussion of these changes.

- *Working capital employed* — Working capital employed increased by $174 million for the six months ended June 30, 2015, compared to the six months ended June 30, 2014, after adjusting for changes in debt, restricted cash and mark-to-market related balances which did not impact cash provided by operating activities. The increase was primarily due to the change in net margining requirements and an increase in the purchase of environmental allowances for the six months ended June 30, 2015 compared to the six months ended June 30, 2014.

- *Interest paid* — Cash paid for interest increased by $34 million to $322 million for the six months ended June 30, 2015, from $288 million for the six months ended June 30, 2014. The increase was primarily due to our refinancing activity and the timing of interest payments.

- *Debt modification and extinguishment payments* — During the six months ended June 30, 2015, we made cash payments of $13 million related to the issuance costs associated with our 2022 First Lien Term Loan, and cash payments of $18 million related to the repayment penalties of a portion of our 2023 First Lien Notes. There was no similar activity for the six months ended June 30, 2014.

Net Cash Used In Investing Activities

Cash used in investing activities for the six months ended June 30, 2015 was $246 million compared to $900 million for the six months ended June 30, 2014. The decrease was primarily due to:

- *Purchase of Guadalupe Energy Center* — During the six months ended June 30, 2014, we purchased a natural gas-fired, combined-cycle power plant located in Guadalupe County, Texas for $656 million. There were no acquisitions during the six months ended June 30, 2015.

- *Capital expenditures* — Capital expenditures for the six months ended June 30, 2015, were $279 million, an increase of $21 million, compared to expenditures of $258 million for the six months ended June 30, 2014. The increase was primarily due to higher expenditures on construction projects and outages during the six months ended June 30, 2015, as compared to the six months ended June 30, 2014.

- *Restricted cash* — Restricted cash decreased $34 million for the six months ended June 30, 2015, compared to a decrease of $14 million for the six months ended June 30, 2014. The decrease was primarily due to payments for principal and interest on project debt and an increase in payments for operating expenses on RCEC, in addition to an increase in funding of the major maintenance reserve account for our Pasadena Power Plant.

Net Cash Provided By (Used In) Financing Activities

Cash used in financing activities was $68 million for the six months ended June 30, 2015, compared to cash provided by financing activities of $52 million for the six months ended June 30, 2014. The decrease was primarily due to:

- *CCFC refinancing* — During the six months ended June 30, 2014, we received proceeds of $420 million under the CCFC Term Loans, which were used to fund a portion of the purchase price paid in connection with the acquisition of the Guadalupe Energy Center. There was no similar activity during the six months ended June 30, 2015.

- *Issuance of First Lien Term Loans* — During the six months ended June 30, 2015, we received proceeds of approximately $1.6 billion from the issuance of the 2022 First Lien Term Loan which was used together with operating cash on hand to repay the 2018 First Lien Term Loan. There was no similar activity during the six months ended June 30, 2014.

- *Issuance of Senior Unsecured Notes* — During the six months ended June 30, 2015, we received proceeds of $650 million from the issuance of the 2024 Senior Unsecured Notes which were used to replenish cash on hand used for the acquisition of Fore River Energy Center in the fourth quarter of 2014, repay $147 million of our 2023 First Lien Notes and other general corporate purposes. There was no similar activity during the six months ended June 30, 2014.
- *Repayments of project debt, notes payable and other* — During the six months ended June 30, 2015, we made repayments of $85 million compared to $55 million for the six months ended June 30, 2014. The increase is related to the repayments on project debt for RCEC and an increase in repayment on project debt for Calpine Steamboat Holdings, LLC, partially offset by a decrease in repayment on project debt for Los Esteros Critical Energy Facility, LLC (“LECEF”).
- *Financing costs* — During the six months ended June 30, 2015, we incurred finance costs of $17 million compared to $10 million for the six months ended June 30, 2014. The increase was primarily due to the issuances of our 2024 Senior Unsecured Notes and our 2022 First Lien Term Loan, and the re-pricing of the project debt for LECEF during the six months ended June 30, 2015. There was no similar activity during the six months ended June 30, 2014.
- *Stock repurchases* — During the six months ended June 30, 2015, we made payments of $454 million to repurchase our common stock compared to $297 million during the six months ended June 30, 2014.
- *Stock options proceeds* — During the six months ended June 30, 2015, we received proceeds from the exercise of stock options of $6 million compared to $15 million during the six months ended June 30, 2014.

Off Balance Sheet Arrangements

There have been no material changes to our off balance sheet arrangements from those disclosed in “Management’s Discussion and Analysis of Financial Condition and Results of Operations” in our 2014 Form 10-K.

RISK MANAGEMENT AND COMMODITY ACCOUNTING

Our commercial hedging and optimization strategies are designed to maximize our risk-adjusted Commodity Margin by leveraging our knowledge, experience and fundamental views on natural gas and power. We actively manage our risk exposures with a variety of physical and financial instruments with varying time horizons. These instruments include PPAs, tolling arrangements, Heat Rate swaps and options, load sales, steam sales, buying and selling standard physical products, buying and selling exchange traded instruments, buying and selling environmental and capacity products, gas transportation and storage arrangements, electric transmission service and other contracts for the sale and purchase of power products.

We conduct our 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 estimates 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 and are separately stated on our Consolidated Condensed Statements of Operations in mark-to-market gain/loss as a component of operating revenues (for power and Heat Rate swaps and options) and fuel and purchased energy expense (for natural gas contracts, environmental product contracts, swaps and options). Our future hedged status and marketing and optimization activities are subject to change as determined by our commercial operations group, Chief Risk Officer, senior management and Board of Directors.

At any point in time, 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. 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 currently remain susceptible to significant price movements for 2015 and beyond. When we elect to enter into these transactions, we are able to economically hedge a portion of our Spark Spread at pre-determined generation and price levels.

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. See Note 6 of the Notes to Consolidated Condensed Financial Statements for further discussion of our derivative instruments.

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, primarily 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 decreased to approximately $2.2 billion at June 30, 2015, when compared to approximately $2.5 billion at December 31, 2014, and our derivative liabilities have decreased to approximately $1.9 billion at June 30, 2015, when compared to approximately $2.2 billion at December 31, 2014. The fair value of our level 3 derivative assets and liabilities at June 30, 2015 represent a small portion of our total assets and liabilities measured at fair value (approximately 9% and 2%, respectively). During the six months ended June 30, 2015, the fair value of our level 3 assets and liabilities increased primarily due to declines in forward power prices and the related impact on longer-dated power sales contracts. See Note 5 of the Notes to Consolidated Condensed 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, 2015, through June 30, 2015, is summarized in the table below (in millions):

	Commodity Instruments	Interest Rate Swaps	Total
Fair value of contracts outstanding at January 1, 2015	$ 381	$ (110)	$ 271
Items recognized or otherwise settled during the period[(1)(2)]	(208)	22	(186)
Fair value attributable to new contracts	66	—	66
Changes in fair value attributable to price movements	257	(14)	243
Changes in fair value attributable to nonperformance risk	(10)	—	(10)
Fair value of contracts outstanding at June 30, 2015[(3)]	$ 486	$ (102)	$ 384

(1) Commodity contract settlements consist of the realization of previously recognized gains on contracts not designated as hedging instruments of $232 million (represents a portion of Commodity revenue and Commodity expense as reported on our Consolidated Condensed Statements of Operations) and $24 million related to current period gains from other changes in derivative assets and liabilities not reflected in OCI or earnings.

(2) Interest rate settlements consist of $21 million related to realized losses from settlements of designated cash flow hedges and $1 million related to realized losses from settlements of undesignated interest rate swaps (represents a portion of interest expense as reported on our Consolidated Condensed Statements of Operations).

(3) Net commodity and interest rate derivative assets and liabilities reported in Notes 5 and 6 of the Notes to Consolidated Condensed Financial Statements.

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

The following tables detail the components of our total activity for both the net realized gain (loss) and the net mark-to-market gain (loss) recognized from our derivative instruments in earnings and where these components were recorded on our Consolidated Condensed Statements of Operations for the periods indicated (in millions):

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Realized gain (loss)[(1)]				
Commodity derivative instruments	$ 104	$ 18	$ 163	$ (21)
Total realized gain (loss)	$ 104	$ 18	$ 163	$ (21)
Mark-to-market gain (loss)[(2)]				
Commodity derivative instruments	$ (1)	$ 141	$ 69	$ 68
Interest rate swaps	—	1	1	2
Total mark-to-market gain (loss)	$ (1)	$ 142	$ 70	$ 70
Total activity, net	$ 103	$ 160	$ 233	$ 49

(1) Does not include the realized value associated with derivative instruments that settle through physical delivery.

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2015	2014	2015	2014
Realized and mark-to-market gain (loss)				
Derivatives contracts included in operating revenues	$ 115	$ 158	$ 234	$ (79)
Derivatives contracts included in fuel and purchased energy expense	(12)	1	(2)	126
Interest rate swaps included in interest expense	—	1	1	2
Total activity, net	$ 103	$ 160	$ 233	$ 49

Commodity Price Risk — Commodity price risk results 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 June 30, 2015, based on price source and the period during which the instruments will mature, are summarized in the table below (in millions):

Fair Value Source	2015	2016-2017	2018-2019	After 2019	Total
Prices actively quoted	$ 141	$ 37	$ —	$ —	$ 178
Prices provided by other external sources	53	21	1	—	75
Prices based on models and other valuation methods	16	48	49	120	233
Total fair value	$ 210	$ 106	$ 50	$ 120	$ 486

We measure the energy commodity price risk in our portfolio on a daily basis using a VAR model to estimate the 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 comprising energy commodity derivatives, expected generation and natural gas consumption from our power plants, PPAs, and other physical and financial transactions. We measure VAR using a variance/covariance approach based on a confidence level of 95%, a one-day holding period and actual observed historical correlation. While we believe that our VAR assumptions and approximations are reasonable, different assumptions and/or approximations could produce materially different estimates.

The table below presents the high, low and average of our daily VAR for the three and six months ended June 30, 2015 and 2014 (in millions):

	2015	2014
Three months ended June 30:		
High	$ 23	$ 44
Low	$ 17	$ 34
Average	$ 19	$ 38
Six months ended June 30:		
High	$ 38	$ 52
Low	$ 17	$ 34
Average	$ 24	$ 42
As of June 30	$ 23	$ 39

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 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 analysis, non-statistical scenario analysis, including stress testing, and daily position report analysis.

Since the fourth quarter of 2012, we have experienced diminished liquidity in the forward commodity markets resulting from a decrease in participation of counterparties in the marketplace with which to transact our hedging activities. Although this occurrence of diminished liquidity has not had a material adverse impact on our results of operations or financial condition, should these conditions persist, it could decrease our ability to hedge our forward commodity price risk and create incremental volatility in our earnings.

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 7 of the Notes to Consolidated Condensed 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 customers relating to our sales of power and steam and our hedging and optimization activities. We believe that our credit policies and practices adequately monitor our credit risk, and currently our counterparties are performing 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 Condensed Balance Sheets. Our counterparty credit quality associated with the net fair value of outstanding derivative commodity instruments is included in our derivative assets and (liabilities) at June 30, 2015, and the period during which the instruments will mature are summarized in the table below (in millions):

Credit Quality (Based on Standard & Poor's Ratings as of June 30, 2015)	**2015**	**2016-2017**	**2018-2019**	**After 2019**	**Total**
Investment grade	$ 208	$ 98	$ 40	$ 105	$ 451
Non-investment grade	(4)	(1)	—	—	(5)
No external ratings	6	9	10	15	40
Total fair value	$ 210	$ 106	$ 50	$ 120	$ 486

Interest Rate Risk — 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 hedging our variable rate debt of approximately $(7) million at June 30, 2015.

New Accounting Standards and Disclosure Requirements

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

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

The information required to be disclosed under this Item 3 is set forth under Item 2 "Management's Discussion and Analysis of Financial Condition and Results of Operations — Risk Management and Commodity Accounting." This information should be read in conjunction with the information disclosed in our 2014 Form 10-K.

Item 4. ***Controls and Procedures***

Disclosure Controls and Procedures

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) and 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.

Changes in Internal Control Over Financial Reporting

During the second quarter of 2015, 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.

PART II — OTHER INFORMATION

Item 1. ***Legal Proceedings***

See Note 11 of the Notes to Consolidated Condensed Financial Statements for a description of our legal proceedings.

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

There were no material changes to the description of the risk factors associated with our business previously disclosed in Part I, Item 1A "Risk Factors" of our 2014 Form 10-K.

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

Repurchase of Equity Securities

Period	(a) Total Number of Shares Purchased[1]		(b) Average Price Paid Per Share	(c) Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs[2]		(d) Maximum Dollar Value of Shares That May Yet Be Purchased Under the Plans or Programs (in millions)[2]
April	1,498,360	$	22.71	1,495,310	$	601
May	752,701	$	20.76	750,331	$	585
June	10,672,598	$	19.00	10,543,462	$	382
Total	12,923,659	$	19.53	12,789,103	$	382

(1) To satisfy tax withholding obligations associated with the vesting of restricted stock awarded to employees and with net share employee stock option exercises under the Equity Plan, during the second quarter of 2015, we withheld a total of 10,067 shares and 124,489 shares, respectively, that are included in the total number of shares purchased.

(2) In November 2014, our Board authorized an increase in the total authorization of our multi-year share repurchase program to $1.0 billion. There is no expiration date on the repurchase authorization and the amount and timing of future share repurchases, if any, will be determined as market and business conditions warrant.

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

None.

Item 4. ***Mine Safety Disclosures***

Not applicable.

Item 5. ***Other Information***

None.

Item 6. ***Exhibits***

EXHIBIT INDEX

Exhibit Number	Description
3.1	Amended and Restated Bylaws of Calpine Corporation (incorporated by reference to Exhibit 3.1 to the Company's Current Report on Form 8-K filed with the SEC on May 13, 2015).
10.1	Credit Agreement, dated May 28, 2015 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 (incorporated by reference to Exhibit 10.1 to the Company's Current Report on Form 8-K filed with the SEC on May 28, 2015).
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 the Chief Executive Officer and the 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.
101.PRE	XBRL Taxonomy Extension Presentation Linkbase.

* Furnished herewith.

SIGNATURES

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

CALPINE CORPORATION
(Registrant)

By: /s/ ZAMIR RAUF

Zamir Rauf
Executive Vice President and Chief Financial Officer
(Principal Financial Officer)

Date: July 29, 2015

EXHIBIT INDEX

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101.INS	XBRL Instance Document.
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101.PRE	XBRL Taxonomy Extension Presentation Linkbase.

* Furnished herewith.

EX-31.1 2 cpn_exhibit311x06302015.htm SECTION 302 CERTIFICATION OF CHIEF EXECUTIVE OFFICER

EXHIBIT 31.1

CERTIFICATIONS

I, John B. (Thad) Hill III, certify that:

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

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

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

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

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

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

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

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

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

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

Date: July 29, 2015

/s/ JOHN B. (THAD) HILL III

John B. (Thad) Hill III

President, Chief Executive Officer and Director

Calpine Corporation

EX-31.2 3 cpn_exhibit312x06302015.htm SECTION 302 CERTIFICATION OF CHIEF FINANCIAL OFFICER

EXHIBIT 31.2

CERTIFICATIONS

I, Zamir Rauf, certify that:

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

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements, and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

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

a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

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

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

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

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

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

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

Date: July 29, 2015

/s/ ZAMIR RAUF

Zamir Rauf

Executive Vice President and
Chief Financial Officer

EX-32.1 4 cpn_exhibit321x06302015.htm CERTIFICATION OF CHIEF EXECUTIVE OFFICER AND CHIEF FINANCIAL OFFICER

EXHIBIT 32.1

CERTIFICATION PURSUANT TO
18 U.S.C. SECTION 1350,
AS ADOPTED PURSUANT TO
SECTION 906 OF THE SARBANES-OXLEY ACT OF 2002

In connection with the Quarterly Report of Calpine Corporation (the “Company”) on Form 10-Q for the period ended June 30, 2015, as filed with the Securities and Exchange Commission on the date hereof (the “Report”), each of the undersigned does hereby certify, pursuant to 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, that, to the best of his or her knowledge, based upon a review of the Report:

(1) The Report fully complies with the requirements of Section 13(a) or 15(d) of the Securities Exchange Act of 1934; and

(2) The information contained in the Report fairly presents, in all material respects, the financial condition and results of operation of the Company.

/s/ JOHN B. (THAD) HILL III	/s/ ZAMIR RAUF
John B. (Thad) Hill III	Zamir Rauf
President,	Executive Vice President and
Chief Executive Officer and Director	Chief Financial Officer
Calpine Corporation	Calpine Corporation

Dated: July 29, 2015

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