CALPINE CORP

FORM 8-K
(Current report filing)

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UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

FORM 8-K

CURRENT REPORT
Pursuant to Section 13 or 15(d) of The Securities Exchange Act of 1934

Date of Report (Date of earliest event reported): **July 27, 2012**

CALPINE CORPORATION
(Exact name of registrant as specified in its charter)

Delaware	**1-12079**	**77-0212977**
(State or other jurisdiction of incorporation)	(Commission File Number)	(IRS Employer Identification No.)

717 Texas Avenue, Suite 1000, Houston, Texas 77002
(Addresses of principal executive offices and zip codes)

Registrant's telephone number, including area code: **(713) 830-2000**

Not applicable
(Former name or former address if changed since last report)

Check the appropriate box below if the Form 8-K filing is intended to simultaneously satisfy the filing obligation of the registrant under any of the following provisions (see General Instruction A.2. below):

- ☐ Written communications pursuant to Rule 425 under the Securities Act (17 CFR 230.425)
- ☐ Soliciting material pursuant to Rule 14a-12 under the Exchange Act (17 CFR 240.14a-12)
- ☐ Pre-commencement communications pursuant to Rule 14d-2(b) under the Exchange Act (17 CFR 240.14d-2(b))
- ☐ Pre-commencement communications pursuant to Rule 13e-4(c) under the Exchange Act (17 CFR 240.13e-4(c))

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ITEM 2.02 — RESULTS OF OPERATIONS AND FINANCIAL CONDITION

On July 27, 2012, Calpine Corporation (the "Company") issued a press release announcing its financial and operating results for the quarter ended June 30, 2012. A copy of the press release is being furnished as Exhibit 99.1 hereto. As set forth in the press release, the Company will host a conference call to discuss its financial and operating results for the second quarter of 2012 on Friday, July 27, 2012, at 10 a.m. ET / 9 a.m. CT. A listen-only webcast of the call may be accessed through the Company's website at www.calpine.com, or by dialing 800-447-0521 in the United States or 847-413-3238 outside the United States. The confirmation code is 32797758.

An archived recording of the call will be made available on the Company's website and can be accessed by dialing 888-843-7419 in the United States or 630-652-3042 outside the United States and providing confirmation code 32797758. Presentation materials to accompany the conference call will be made available on the Company's website on July 27, 2012.

The information in this Form 8-K, including Exhibit 99.1, shall not be deemed "filed" for purposes of Section 18 of the Securities and Exchange Act of 1934, as amended (the "1934 Act"), nor shall it be deemed "incorporated by reference" into any filing under the Securities Act of 1933, as amended, or the 1934 Act, except as may be expressly set forth by specific reference in such filing.

ITEM 9.01 — FINANCIAL STATEMENTS AND EXHIBITS

(d) *Exhibits*

Exhibit No.	Description
99.1	Calpine Corporation Press Release dated July 27, 2012.*

* 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 hereunto duly authorized.

CALPINE CORPORATION

By: /s/ ZAMIR RAUF

Zamir Rauf
Executive Vice President and
Chief Financial Officer

July 27, 2012

EXHIBIT INDEX

Exhibit No.	Description
99.1	Calpine Corporation Press Release dated July 27, 2012.*

* Furnished herewith.

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CALPINE REPORTS SECOND QUARTER 2012 RESULTS, TIGHTENS 2012 GUIDANCE RANGE BY RAISING LOWER END

Summary of Second Quarter 2012 Financial Results (in millions) :

	Three Months Ended June 30,			Six Months Ended June 30,		
	2012	2011	*% Change*	2012	2011	*% Change*
Operating Revenues [1]	$ 879	$ 1,633	*(46.2)%*	$ 2,115	$ 3,132	*(32.5)%*
Commodity Margin	$ 609	$ 607	*0.3 %*	$ 1,126	$ 1,096	*2.7 %*
Adjusted EBITDA	$ 403	$ 406	*(0.7)%*	$ 728	$ 709	*2.7 %*
Adjusted Recurring Free Cash Flow	$ 87	$ 41	*112.2 %*	$ 60	$ 20	*200.0 %*
Per Share	*$ 0.19*	*$ 0.08*	*137.5 %*	*$ 0.13*	*$ 0.04*	*225.0 %*
Net Loss [2]	$ (329)	$ (70)		$ (338)	$ (367)	
Net Income (Loss), As Adjusted [3]	$ 14	$ (55)		$ (51)	$ (165)	

Tightening 2012 Full Year Guidance:

	Prior Guidance (as of April 2012)	Current Guidance
	(in millions)	
Adjusted EBITDA	$1,675 - 1,800	$1,700 - 1,800
Adjusted Recurring Free Cash Flow	$470 - 595	$500 - 600

Recent Achievements:

- Operations:
  - Generated 27 million MWh [4] of electricity in the second quarter of 2012, a record for the period and a 37% increase compared to the second quarter of 2011
  - Held year-to-date plant operating expense [5] essentially flat, despite a 44% increase in generation
  - Delivered lowest year-to-date fleetwide forced outage factor on record: 2.0%
  - Produced highest year-to-date fleetwide starting reliability on record: 98%
  - Achieved best year-to-date safety performance on record
- Commercial:
  - Cleared approximately 4,200 MW of PJM capacity in 2015/2016 auction
  - Signed approximately 900 MW of long-term capacity and energy contracts
  - Achieved constructive near-term resolution for Sutter Energy Center, providing a capacity contract for balance of 2012 while engaging broader market reform discussion in California
- Capital Structure:
  - Repurchased approximately $284 million of our common stock during the second quarter, bringing our cumulative repurchases to $409 million of the $600 million authorized under our program

[1] The decline in operating revenues was affected by $(302) million and $(280) million of unrealized mark-to-market losses in the three and six months ended June 30, 2012, respectively, and $60 million and $35 million of unrealized mark-to-market gains in the three and six months ended June 30, 2011, respectively.

[2] Reported as net loss attributable to Calpine on our Consolidated Condensed Statements of Operations.
[3] Refer to Table 1 for further detail of Net Income (Loss), As Adjusted.
[4] Includes generation from power plants owned but not operated by Calpine and our share of generation from unconsolidated power plants.
[5] Increase in plant operating expense excludes changes in major maintenance expense, stock-based compensation expense and non-cash loss on disposition of assets. See the table titled "Consolidated Adjusted EBITDA Reconciliation" for the actual amounts of these items for the three and six months ended June 30, 2012 and 2011.

(HOUSTON, Texas) July 27, 2012 – Calpine Corporation (NYSE: CPN) today reported second quarter 2012 Adjusted EBITDA of $403 million, compared to $406 million in the prior year period, and Adjusted Recurring Free Cash Flow of $87 million, compared to $41 million in the prior year period. Net Loss [2] for the second quarter was $329 million, or $0.69 per diluted share, compared to $70 million, or $0.14 per diluted share, in the prior year period. Net Income, As Adjusted [3], for the second quarter of 2012 was $14 million compared to Net Loss, As Adjusted [3], of $55 million in the prior year period.

The key driver of the increase in Net Loss [2] was non-cash, unrealized mark-to-market losses on forward commodity hedges, which also contributed to a year-over-year decline in revenue. The unrealized losses were largely associated with a temporary spike in near-term forward power prices in Texas during the last week of the quarter, which has since subsided, thus substantially mitigating the impact. Meanwhile, these unrealized losses do not account for the potential increase in the economic value of the underlying physical generation, for which offsetting realized gains are expected primarily during the third quarter. Regardless, unrealized mark-to-market gains and losses have always been excluded from Adjusted EBITDA and Net Income (Loss), as Adjusted [3], in order to provide a clearer view of realized results, which better represent the operating performance of our company.

Year-to-date 2012 Adjusted EBITDA was $728 million, compared to $709 million in the prior year period, and Adjusted Recurring Free Cash Flow was $60 million, compared to $20 million in the prior year period. Net Loss [2] for the first half of 2012 was $338 million, or $0.71 per diluted share, compared to $367 million, or $0.75 per diluted share, in the prior year period. Net Loss, As Adjusted [3], for the first half of 2012 was $51 million compared to $165 million in the prior year period.

“Calpine continues to capitalize on the secular shift toward greater utilization of combined-cycle gas turbines in the power generation industry,” said Jack Fusco, Calpine’s President and Chief Executive Officer. “Our versatile fleet generated 56 million MWhs during the first half of 2012, 44% more than last year, as natural gas-fired generation continued to take market share from coal. This increased productivity, coupled with our focus on operational excellence, drove a 30% reduction in our plant operating expenses per MWh for the first half of 2012 and yielded the best year-to-date forced outage factor and starting reliability on record. Similarly, our plant personnel achieved the best year-to-date safety performance on record.

“Natural gas is becoming the power production fuel of choice. According to the Energy Information Administration, during April of 2012, natural gas-fired power generation equaled coal-fired generation in America for the first time ever. Natural gas-fired generation is cheaper, more efficient, more flexible and environmentally cleaner than coal. As the largest operator of combined-cycle gas turbines in the U.S., Calpine stands to benefit as the fundamentals of each of our core wholesale competitive power markets increase the demand and margins for natural gas-fired generation, whether driven by coal retirements in the Eastern U.S., increasing electric demand in Texas or the need for flexible generation to backstop intermittent renewables in California.”

“In addition to the fundamentals of our business driving value, Calpine employs a disciplined capital allocation philosophy to maximize total shareholder return,” said Zamir Rauf, Calpine’s Chief Financial Officer. “Our ability to maintain strong Adjusted Recurring Free Cash Flow, substantial liquidity and a strong balance sheet enables us to evaluate organic growth, M&A and potential divestitures, while retaining the flexibility to return capital to shareholders. All investments must be free cash flow accretive and are measured against repurchasing our own shares. So far in 2012, we have announced $1.3 billion of capital allocation activities, including doubling our share repurchase program to $600 million. During the second quarter, we repurchased approximately 16 million shares of our common stock, bringing our cumulative repurchases to 24.5 million shares. As we decrease the number of shares outstanding, viewing our financial performance on a per-share basis will more accurately reflect our total shareholder return.”

SUMMARY OF FINANCIAL PERFORMANCE

Second Quarter Results

Adjusted EBITDA for the second quarter of 2012 was $403 million compared to $406 million in the prior year period. The year-over-year decrease in Adjusted EBITDA was primarily due to relatively consistent Commodity Margin, offset by a modest increase in plant operating expense [5] associated with a favorable property tax settlement recognized in the second quarter of 2011 that did not benefit the current year period. Though comparable year-over-year, Commodity Margin was impacted primarily by:

- \+ higher generation as a result of increased market opportunities primarily driven by lower natural gas prices and higher spark spreads in the second quarter of 2012 compared to the prior year period, offset by
- – lower contribution from hedges and
- – lower revenue due to lower regulatory capacity payments and the expiration of contracts subsequent to the second quarter of 2011.

Net Loss [2] was $329 million for the second quarter of 2012, compared to $70 million in the prior year period. As detailed in Table 1, Net Income, As Adjusted [3], was $14 million in the second quarter of 2012 compared to Net Loss, As Adjusted [3], of $55 million in the prior year period. The year-over-year improvement was driven largely by:

- \+ a decrease in income tax expense as a result of lower state and foreign jurisdiction income taxes due to the increase in pre-tax losses in the current period, and
- \+ an increase in income from unconsolidated investments, partially offset by
- – a modest increase in plant operating expense [5], as previously discussed.

Year-to-Date Results

Adjusted EBITDA for the six months ended June 30, 2012, was $728 million compared to $709 million in the prior year period. The year-over-year increase in Adjusted EBITDA was primarily due to a $30 million increase in Commodity Margin, partially offset by modest increases in plant operating expense [5] and sales, general and administrative expenses [6]. The increase in Commodity Margin was primarily due to:

- \+ an increase in generation volumes driven primarily by lower natural gas prices and higher spark spreads in the first half of 2012 compared to the prior year period and
- \+ an extreme cold weather event in Texas in February 2011 that negatively impacted our revenues for the first half of the year, which did not recur in the current year, partially offset by
- – lower contribution from hedges and
- – lower revenue resulting from lower regulatory capacity payments and contracts that expired subsequent to the first half of 2011.

Net Loss [2] decreased to $338 million for the six months ended June 30, 2012, compared to $367 million in the prior year period. As detailed in Table 1, Net Loss, As Adjusted [3], was $51 million in the six months ended June 30, 2012, compared to $165 million in the prior year period. The year-over-year improvement in Net Loss, As Adjusted [3], was driven largely by:

- \+ higher Commodity Margin, as previously discussed, and
- \+ lower income tax benefit resulting from a decrease in various state and foreign jurisdiction income taxes in the first half of 2012 compared to the prior year period, due to the decrease in pre-tax losses in the current period.

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[6] Increase in sales, general and administrative expense excludes changes in stock-based compensation expense, amortization and other items. See the table titled “Consolidated Adjusted EBITDA Reconciliation” for the actual amounts of these items for the six months ended June 30, 2012 and 2011.

Table 1: Net Income (Loss), As Adjusted

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in millions)			
Net loss attributable to Calpine	$ (329)	$ (70)	$ (338)	$ (367)
Debt extinguishment costs [1]	—	5	12	98
Unrealized MtM (gain) loss on derivatives [1] [2]	343	(50)	119	77
Other items [1] [3]	—	60	156	27
Net Income (Loss), As Adjusted [4]	$ 14	$ (55)	$ (51)	$ (165)

(1) Shown net of tax, assuming a 0% effective tax rate for these items.
(2) In addition to changes in market value on derivatives not designated as hedges, changes in unrealized gain (loss) also includes de-designation of interest rate swap cash flow hedges and related reclassification from AOCI into earnings, hedge ineffectiveness and adjustments to reflect changes in credit default risk exposure.
(3) Other items include realized mark-to-market losses associated with the settlement of non-hedged interest rate swaps totaling nil and $156 million for the three and six months ended June 30, 2012, respectively, and $60 million and $103 million for the three and six months ended June 30, 2011, respectively. Other items for the six months ended June 30, 2011, also include a $76 million federal deferred income tax benefit associated with our election to consolidate our CCFC subsidiary for tax reporting purposes.
(4) See "Regulation G Reconciliations" for further discussion of Net Income (Loss), As Adjusted.

REGIONAL SEGMENT REVIEW OF RESULTS

Table 2: Commodity Margin by Segment (in millions)

	Three Months Ended June 30,			Six Months Ended June 30,		
	2012	2011	Variance	2012	2011	Variance
West	$ 210	$ 236	(26)	$ 418	$ 469	(51)
Texas	145	128	17	254	195	59
North	181	184	(3)	325	319	6
Southeast	73	59	14	129	113	16
Total	$ 609	$ 607	2	$ 1,126	$ 1,096	30

West Region

Second Quarter: Commodity Margin in our West segment decreased by $26 million in the second quarter of 2012 compared to the prior year period. Primary drivers were:

– lower contribution from hedges and
– lower revenue due to the expiration of contracts, partially offset by
+ increased generation due to lower hydroelectric generation and a nuclear power plant outage in California, which resulted in higher spark spreads in the second quarter of 2012 compared to the prior year period.

Year-to-Date: Commodity Margin in our West segment decreased by $51 million for the six months ended June 30, 2012, compared to the prior year period. Primary drivers were:

– lower contribution from hedges
– lower revenue due to the expiration of contracts and
– lower Commodity Margin associated with our Sutter Energy Center, which did not run in the first half of 2012, partially offset by
+ increased generation due to lower hydroelectric generation and a nuclear power plant outage in California, which resulted in higher spark spreads in the first half of 2012 compared to the prior year period.

Texas Region

Second Quarter: Commodity Margin in our Texas segment increased by $17 million in the second quarter of 2012 compared to the prior year period. The primary driver was:

+ increased generation driven by increased market opportunities for our combined-cycle natural gas-fired power plants driven by lower natural gas prices and higher spark spreads.

Year-to-Date: Commodity Margin in our Texas segment increased by $59 million for the six months ended June 30, 2012, compared to the prior year period. Primary drivers were:

+ higher generation driven by increased market opportunities primarily due to lower natural gas prices and higher spark spreads
+ increase in Commodity Margin earned during overnight periods related to the must-run obligations of certain of our cogeneration power plants and
+ an extreme cold weather event in Texas in February 2011 that negatively impacted our revenues for the first half of the prior year, which did not recur in the current year, partially offset by
– lower super-peak power prices resulting from milder weather conditions during much of the first half of 2012 compared to the prior year period.

North Region

Second Quarter : Commodity Margin in our North segment decreased by $3 million in the second quarter of 2012 compared to the prior year period. Primary drivers were:

– lower regulatory capacity revenues, partially offset by
+ higher generation driven by increased market opportunities due to higher off-peak spark spreads in the second quarter of 2012 compared to the prior year period and
+ a PPA associated with our York Energy Center that became effective in June 2011.

Year-to-Date : Commodity Margin in our North segment increased by $6 million in the six months ended June 30, 2012, compared to the prior year period. Primary drivers were:

+ York Energy Center achieving commercial operation in March 2011
+ an increase in Commodity Margin from fixed-price power contracts that benefited from lower natural gas prices and
+ higher generation driven by increased market opportunities primarily due to lower natural gas prices and higher off-peak spark spreads, partially offset by
– lower regulatory capacity revenues and
– lower super-peak power prices resulting from milder weather conditions in the first quarter of 2012 compared to the prior year period.

Southeast Region

Second Quarter: Commodity Margin in our Southeast segment increased by $14 million in the second quarter of 2012 compared to the prior year period. Primary drivers were:

+ higher generation driven by increased market opportunities primarily due to lower natural gas prices and higher spark spreads, partially offset by
– lower revenues resulting from the expiration of a PPA subsequent to the second quarter of 2011.

Year-to-Date: Commodity Margin in our Southeast segment increased by $16 million in the six months ended June 30, 2012, compared to the prior year period. The year-to-date results were largely impacted by the same factors that drove comparative performance for the second quarter, as previously discussed.

LIQUIDITY AND CAPITAL RESOURCES

Table 3: Liquidity

	June 30, 2012	December 31, 2011
	(in millions)	
Cash and cash equivalents, corporate [1]	$ 409	$ 946
Cash and cash equivalents, non-corporate	178	306
Total cash and cash equivalents [2]	587	1,252
Restricted cash	175	194
Corporate Revolving Facility availability	615	560
Letter of credit availability [3]	44	7
Total current liquidity availability	$ 1,421	$ 2,013

(1) Includes $45 million and $34 million of margin deposits held by us posted by our counterparties at June 30, 2012, and December 31, 2011, respectively.
(2) Cash and cash equivalents decreased primarily resulting from $290 million in share repurchases, $156 million in payments to terminate our legacy interest rate swaps formerly hedging our First Lien Credit Facility and a $111 million increase in margin deposits in support of derivative contracts driven by the impact of a near term increase in forward power prices and corresponding market heat rate expansion in the ERCOT region.
(3) Includes availability under our CDHI letter of credit facility. On January 10, 2012, we increased the CDHI letter of credit facility to $300 million and extended the maturity date to January 2, 2016.

Liquidity at the end of the second quarter of 2012 was $1.4 billion. The decrease experienced during the first half of the year was largely due to $290 million in share repurchases, $156 million in payments to terminate our legacy interest rate swaps and a $111 million temporary increase in margin deposits in support of derivative contracts utilized in hedging our asset portfolio. Capital expenditures totaling $369 million were primarily funded by borrowings under our construction project financings, which did not impact liquidity, and cash flows from operations.

Cash flows from operating activities for the six months ended June 30, 2012, resulted in net outflows of $32 million compared to net inflows of $239 million in the prior year period. The decrease in cash provided by operating activities was primarily the result of an increase in working capital employed due to increased margin deposits required as a result of a near term increase in forward power prices and corresponding market heat rate expansion in the ERCOT region during the last several days of June 2012.

Cash flows used in investing activities were $513 million for the six months ended June 30, 2012, compared to $421 million in the prior year period, driven largely by our termination of the legacy interest rate swaps and by an increase in capital expenditures associated with construction activity at our Russell City Energy Center and Los Esteros Critical Energy Facility along with our turbine upgrade program.

Cash flows used in financing activities were $120 million for the six months ended June 30, 2012, and were primarily related to the payments we made under our share repurchase program, offset by the receipt of proceeds from project financings related to our Russell City and Los Esteros construction projects. In addition, we incurred lower financing costs and lower repayments on project debt due in part to the refinancing activities we completed in the first half of 2011.

Adjusted Recurring Free Cash Flow was $60 million for the six months ended June 30, 2012, compared to $20 million for the prior year period. Adjusted Recurring Free Cash Flow increased during the period primarily due to a $19 million increase in Adjusted EBITDA. Lower maintenance capital expenditures related to our plant outage schedule and lower interest payments further contributed to the increase compared to the prior year period.

SHARE REPURCHASE PROGRAM

On August 23, 2011, we announced that our Board of Directors had authorized the repurchase of up to $300 million in shares of our common stock. In April 2012, our Board of Directors authorized us to double the size of our share repurchase program, increasing our permitted cumulative repurchases to $600 million in shares of our common stock. The announced share repurchase program did not specify an expiration date. The repurchases may be commenced or suspended from time to time without prior notice. Through the filing of this release, a total of 24.5 million shares of our outstanding common stock have been repurchased under this program for approximately $409 million at an average price of $16.65 per share. The shares repurchased as of the date of this release were purchased in open market transactions.

PLANT DEVELOPMENT

West :
Russell City Energy Center: Construction at our Russell City Energy Center continues to move forward. Upon completion, this project will bring online approximately 429 MW of net interest baseload capacity (464 MW with peaking capacity) representing our 75% share. Upon completion, the Russell City Energy Center is contracted to deliver its full output to PG&E under a 10-year PPA. Construction is ongoing and COD is expected during the summer of 2013.

Los Esteros: During 2009, we and PG&E negotiated a new PPA to replace the existing California Department of Water Resources contract and facilitate the upgrade of our Los Esteros Critical Energy Facility from a 188 MW simple-cycle generation power plant to a 309 MW combined-cycle generation power plant, which will also increase the efficiency and environmental performance of the power plant by lowering the heat rate. The existing 188 MW simple-cycle facility was shut down at the end of 2011 to allow for major maintenance on the combustion turbines and installation of the new heat recovery steam generators and a steam turbine generator in connection with the new PPA. Construction is ongoing and COD is expected during the summer of 2013.

Texas:
Channel and Deer Park Expansions: We are actively permitting the addition of 520 MW of combined-cycle capacity at existing sites in ERCOT, based on tightening reserve margins and the potential impact of EPA regulations on generation in Texas. At both our Deer Park and Channel Energy Centers, we have the ability to install an additional combustion turbine generator and connect to the existing steam turbine generator to expand the capacity of these facilities and to improve overall plant efficiency. In September and November 2011, we filed air permit applications with the Texas Commission on Environmental Quality and the EPA to expand the Deer Park and Channel Energy Centers by approximately 260 MW each. We continue to move forward with development and permitting activities as well as equipment and construction commitments and expect COD in summer 2014 for these expansions. We are currently evaluating funding sources including but not limited to nonrecourse financing, corporate financing or internally generated funds.

North:
Garrison Energy Center: We are actively permitting 618 MW of new combined-cycle capacity at a development site secured by a lease option with the City of Dover. For the first phase (309 MW), PJM has completed a feasibility study and a system impact study and is currently conducting a facility study. For the second phase (309 MW), a feasibility study has been completed and a system impact study is ongoing. Environmental permitting, site development planning and development engineering are underway, and the first phase's capacity cleared PJM's 2015/2016 base residual auction. We expect to receive the air permit in the fourth quarter of 2012 and expect COD for the first phase by the summer of 2015. We are currently evaluating funding sources including but not limited to nonrecourse financing, corporate financing or internally generated funds.

All Segments:

Turbine Upgrades: We continue to move forward with our turbine upgrade program. Through June 30, 2012, we have completed the upgrade of eleven Siemens and eight GE turbines totaling over 200 MW and have agreed to upgrade approximately three additional turbines (and may upgrade additional turbines in the future).

OPERATIONS UPDATE

Second Quarter 2012 Power Operations Achievements :

- Safety Performance:
  - Maintained stellar safety metrics, recording only one lost-time incident year to date

- Availability Performance:
  - Delivered lowest first half fleetwide forced outage factor on record: 2.0%
  - Maintained impressive second quarter fleetwide starting reliability: 98%

- Cost Performance:
  - Held year-to-date plant operating expense [7] essentially flat, despite a 44% increase in generation, resulting in a 30% improvement on a per-MWh basis

- Geothermal Generation:
  - Provided approximately 1.5 million MWh of renewable baseload generation with a record 0.14% forced outage factor during the second quarter of 2012

- Natural Gas-fired Generation:
  - Increased combined-cycle capacity factor in the first six months of 2012 to 52% compared to 35% in the prior year period
  - Magic Valley Generation Station: 91% capacity factor for the entire second quarter of 2012
  - Decatur Energy Center: 100% starting reliability, 0.00% forced outage factor

Second Quarter 2012 Commercial Operations Achievements:

- Customer-oriented Growth:
  - Entered into a five-year PPA with Southwestern Public Service Company to provide an additional 200 MW of capacity and energy from our Oneta Energy Center beginning June 2014
  - Executed a new five-year resource adequacy contract with PG&E for approximately 280 MW of combined heat and power capacity from our Los Medanos Energy Center commencing in summer 2013
  - Entered into a new seven-year resource adequacy contract with Southern California Edison (SCE) for approximately 280 MW of combined heat and power capacity from our Los Medanos Energy Center commencing in January 2014
  - Executed a new five-year resource adequacy contract with SCE for approximately 120 MW of combined heat and power capacity from our Gilroy Cogeneration Plant commencing in January 2014
  - Amended an existing PPA with Dow Chemical Company for an incremental energy sale of up to approximately 158,000 MWh per year of energy from our Los Medanos Energy Center that runs through February 2025

[7] Change in plant operating expense excludes changes in major maintenance expense, stock-based compensation expense and non-cash loss on disposition of assets. See the table

titled “ Consolidated Adjusted EBITDA Reconciliation ” for the actual amounts of these items for the six months ended June 30, 2012 and 2011.

FINANCIAL OUTLOOK

		Full Year 2012 (in millions)
Adjusted EBITDA	$	1,700 - 1,800
Less:		
Operating lease payments		35
Major maintenance expense and maintenance capital expenditures [1]		350
Accelerated parts purchases to support upgrades [2]		30
Recurring cash interest, net [3]		770
Cash taxes		10
Other		5
Adjusted Recurring Free Cash Flow	$	500 - 600
Non-recurring interest rate swap payments [4]	$	(156)
Growth capital expenditures (net of debt funding)	$	(100)
Riverside sale proceeds	$	392

(1) Includes projected major maintenance expense of $185 million and maintenance capital expenditures of $165 million in 2012. Capital expenditures exclude major construction and development projects. 2012 figures exclude amounts to be funded by project debt.
(2) Incremental impact on 2012 maintenance capital expenditures related to acceleration of future turbine upgrades into 2012 and deferral of use of on-hand parts to post-2012 periods.
(3) Includes fees for letters of credit, net of interest income.
(4) Interest payments related to legacy LIBOR hedges associated with floating rate first lien credit facility, which has been refinanced.

As detailed above, today we are tightening our 2012 guidance. We now project Adjusted EBITDA of $1,700 million to $1,800 million and Adjusted Recurring Free Cash Flow of $500 million to $600 million. We also expect to invest $100 million, net of debt funding, in growth-related projects during the year, including our Garrison Energy Center development project and the expansion of our Deer Park and Channel Energy Centers, as well as our ongoing turbine upgrade program. (Though our construction projects at Russell City and Los Esteros will continue through 2012, we met our equity contribution requirements on these projects in 2011, such that all costs incurred in 2012 and beyond will be funded from the project debt we have secured for these projects.) Finally, we continue to expect to receive approximately $392 million during the fourth quarter of 2012 from one of our customers related to its intended purchase of our Riverside Energy Center.

INVESTOR CONFERENCE CALL AND WEBCAST

We will host a conference call to discuss our financial and operating results for the second quarter of 2012 on Friday, July 27, 2012, at 10 a.m. ET / 9 a.m. CT. A listen-only webcast of the call may be accessed through our website at www.calpine.com , or by dialing (800) 447-0521 in the U.S. or (847) 413-3238 outside the U.S. The confirmation code is 32797758. An archived recording of the call will be made available for a limited time on our website or by dialing (888) 843-7419 in the U.S. or (630) 652-3042 outside the U.S. and providing confirmation code 32797758. Presentation materials to accompany the conference call will be available on our website on July 27, 2012.

ABOUT CALPINE

Calpine Corporation is the largest independent power producer in the U.S., with a fleet of 93 power generation plants representing more than 28,000 megawatts of generation capacity. Last year our plants generated more than 94 million megawatt hours of power for our wholesale customers in 20 states and Canada. Our 91 operating plants as well as two under construction consist primarily of natural gas-fired and renewable geothermal power plants that use advanced technologies to generate power in a low-carbon and environmentally responsible manner. Our modern, clean, efficient and cost-effective fleet stands ready to respond to the increased need for cleaner and more affordable power as the
economy recovers, as new environmental rules are implemented and force older, dirtier plants to retire or reduce generation, as variable renewable power generation from wind and solar grows and with it the need for flexible natural gas generation to assure firm supply to the grid, and finally, as natural gas becomes economically competitive with coal as a fuel for power generation.

Please visit www.calpine.com to learn more about why Calpine is a generation ahead - today.

Calpine's Quarterly Report on Form 10-Q for the quarter ended June 30, 2012, has been filed with the Securities and Exchange Commission (SEC) and may be found on the SEC's website at www.sec.gov .

FORWARD-LOOKING INFORMATION

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

- *Financial results that may be volatile and may not reflect historical trends due to, among other things, fluctuations in prices for commodities such as natural gas and power, changes in U.S. macroeconomic conditions, fluctuations in liquidity and volatility in the energy commodities markets and our ability to hedge risks;*
- *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;*
- *The unknown future impact on our business from the Dodd-Frank Act and the rules to be promulgated thereunder;*
- *Our ability to manage our liquidity needs and to comply with covenants under our First Lien Notes, Corporate Revolving Facility, First Lien Term Loans, CCFC Notes and other existing financing obligations;*
- *Risks associated with the continued economic and financial conditions affecting certain countries in Europe including financial institutions located within those countries and their ability to fund their financial commitments;*
- *Risks associated with the operation, construction and development of power plants including unscheduled outages or delays and plant efficiencies;*
- *Risks related to our geothermal resources, including the adequacy of our steam reserves, unusual or unexpected steam field well and pipeline maintenance requirements, variables associated with the injection of wastewater to the steam reservoir and potential regulations or other requirements related to seismicity concerns that may delay or increase the cost of developing or operating geothermal resources;*
- *Competition, including risks associated with marketing and selling power in the evolving energy markets;*
- *The expiration or early termination of our PPAs and the related results on revenues;*
- *Future capacity revenues may not occur at expected levels;*
- *Natural disasters, such as hurricanes, earthquakes and floods, acts of terrorism or cyber attacks that may impact our power plants or the markets our power plants serve and our corporate headquarters;*
- *Disruptions in or limitations on the transportation of natural gas, fuel oil and transmission of power;*
- *Our ability to manage our customer and counterparty exposure and credit risk, including our commodity positions;*
- *Our ability to attract, motivate and retain key employees;*
- *Present and possible future claims, litigation and enforcement actions; and*
- *Other risks identified in this press release and in our 2011 Form 10-K.*

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 release. 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.

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED CONDENSED STATEMENTS OF OPERATIONS
(Unaudited)

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in millions, except share and per share amounts)			
Operating revenues	$ 879	$ 1,633	$ 2,115	$ 3,132
Operating expenses:				
Fuel and purchased energy expense	612	1,000	1,244	2,069
Plant operating expense	271	261	492	499
Depreciation and amortization expense	138	131	278	262
Sales, general and other administrative expense	35	34	68	66
Other operating expenses	21	22	45	42
Total operating expenses	1,077	1,448	2,127	2,938
(Income) loss from unconsolidated investments in power plants	(5)	2	(14)	(7)
Income (loss) from operations	(193)	183	2	201
Interest expense	184	192	369	383
Loss on interest rate derivatives	—	37	14	146
Interest (income)	(2)	(2)	(5)	(5)
Debt extinguishment costs	—	5	12	98
Other (income) expense, net	6	3	8	10
Loss before income taxes	(381)	(52)	(396)	(431)
Income tax expense (benefit)	(52)	18	(58)	(65)
Net loss	(329)	(70)	(338)	(366)
Net income attributable to the noncontrolling interest	—	—	—	(1)
Net loss attributable to Calpine	$ (329)	$ (70)	$ (338)	$ (367)
Basic and diluted loss per common share attributable to Calpine:				
Weighted average shares of common stock outstanding (in thousands)	471,444	486,411	474,775	486,334
Net loss per common share attributable to Calpine - basic and diluted	$ (0.69)	$ (0.14)	$ (0.71)	$ (0.75)

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED CONDENSED BALANCE SHEETS
(Unaudited)

	June 30, 2012	December 31, 2011
	(in millions, except share and per share amounts)	
ASSETS		
Current assets:		
Cash and cash equivalents	$ 587	$ 1,252
Accounts receivable, net of allowance of $14 and $13	532	598
Margin deposits and other prepaid expense	305	193
Restricted cash, current	124	139
Derivative assets, current	1,049	1,051
Inventory and other current assets	337	329
Total current assets	2,934	3,562
Property, plant and equipment, net	13,109	13,019
Restricted cash, net of current portion	51	55
Investments	76	80
Long-term derivative assets	158	113
Other assets	559	542
Total assets	$ 16,887	$ 17,371
LIABILITIES & STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable	$ 353	$ 435
Accrued interest payable	200	200
Debt, current portion	103	104
Derivative liabilities, current	1,243	1,144
Other current liabilities	274	279
Total current liabilities	2,173	2,162
Debt, net of current portion	10,488	10,321
Long-term derivative liabilities	276	279
Other long-term liabilities	247	245
Total liabilities	13,184	13,007
Commitments and contingencies		
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, 492,024,794 and 490,468,815 shares issued, respectively, and 466,615,007 and 481,743,738 shares outstanding, respectively	1	1
Treasury stock, at cost, 25,409,787 and 8,725,077 shares, respectively	(420)	(125)
Additional paid-in capital	12,320	12,305
Accumulated deficit	(8,037)	(7,699)
Accumulated other comprehensive loss	(223)	(178)
Total Calpine stockholders' equity	3,641	4,304
Noncontrolling interest	62	60
Total stockholders' equity	3,703	4,364

Total liabilities and stockholders' equity	$ 16,887	$ 17,371

CALPINE CORPORATION AND SUBSIDIARIES

CONSOLIDATED CONDENSED STATEMENTS OF CASH FLOWS
(Unaudited)

	Six Months Ended June 30,	
	2012	2011
	(in millions)	
Cash flows from operating activities:		
Net loss	$ (338)	$ (366)
Adjustments to reconcile net loss to net cash provided by (used in) operating activities:		
Depreciation and amortization expense [1]	299	279
Debt extinguishment costs	—	85
Deferred income taxes	(31)	(90)
Loss on disposition of assets	4	9
Unrealized mark-to-market activities, net	119	77
(Income) from unconsolidated investments in power plants	(14)	(7)
Return on unconsolidated investments in power plants	16	6
Stock-based compensation expense	13	12
Other	1	5
Change in operating assets and liabilities:		
Accounts receivable	63	(68)
Derivative instruments, net	(111)	(29)
Other assets	(122)	58
Accounts payable and accrued expenses	(86)	166
Settlement of non-hedging interest rate swaps	156	103
Other liabilities	(1)	(1)
Net cash provided by (used in) operating activities	(32)	239
Cash flows from investing activities:		
Purchases of property, plant and equipment	(369)	(341)
Settlement of non-hedging interest rate swaps	(156)	(103)
Decrease in restricted cash	19	30
Purchases of deferred transmission credits	(12)	(8)
Other	5	1
Net cash used in investing activities	$ (513)	$ (421)

(Table continues)

CALPINE CORPORATION AND SUBSIDIARIES

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

	Six Months Ended June 30,	
	2012	**2011**
	(in millions)	
Cash flows from financing activities:		
Repayment of Term Loans	$ (8)	$ —
Borrowings under First Lien Term Loans	—	1,657
Repayments on NDH Project Debt	—	(1,283)
Issuance of 2023 First Lien Notes	—	1,200
Repayments on First Lien Credit Facility	—	(1,187)
Borrowings from project financing, notes payable and other	226	69
Repayments of project financing, notes payable and other	(46)	(419)
Capital contributions from noncontrolling interest holder	—	34
Financing costs	(5)	(67)
Stock repurchases	(290)	—
Other	3	(2)
Net cash provided by (used in) financing activities	(120)	2
Net decrease in cash and cash equivalents	(665)	(180)
Cash and cash equivalents, beginning of period	1,252	1,327
Cash and cash equivalents, end of period	$ 587	$ 1,147
Cash paid during the period for:		
Interest, net of amounts capitalized	$ 352	$ 292
Income taxes	$ 13	$ 12
Supplemental disclosure of non-cash investing activities:		
Change in capital expenditures included in accounts payable	$ 3	$ 21

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

REGULATION G RECONCILIATIONS

Net Income (Loss), As Adjusted, Commodity Margin, Adjusted EBITDA and Adjusted Recurring Free Cash Flow are non-GAAP financial measures that we use as measures of our performance. These measures should be viewed as a supplement to and not a substitute for our U.S. GAAP measures of performance.

Net Income (Loss), As Adjusted, represents net income (loss) attributable to Calpine, adjusted for certain non-cash and non-recurring items as previously detailed in Table 1, including debt extinguishment costs, unrealized mark-to-market (gain) loss on derivatives, and other adjustments. Net Income (Loss), As Adjusted, is presented because we believe it is a useful tool for assessing the operating performance of our company in the current period. Net Income (Loss), As Adjusted, is not intended to represent net income (loss), 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.

Commodity Margin includes our power and steam revenues, sales of purchased power and physical natural gas, capacity revenue, revenue from renewable energy credits, sales of surplus emission allowances, transmission revenue and expenses, fuel and purchased energy expense, fuel transportation expense, RGGI compliance and other environmental costs, and cash settlements from our marketing, hedging and optimization activities including natural gas transactions hedging future power sales that are included in mark-to-market activity, but excludes the unrealized portion of our mark-to-market activity and other revenues. Commodity Margin is presented because we believe it is a useful tool for assessing the performance of our core operations, and it is a key operational measure reviewed by our chief operating decision maker. Commodity Margin does not intend to represent income (loss) 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.

Adjusted EBITDA represents earnings before interest, taxes, depreciation and amortization, adjusted for certain non-cash and non-recurring items as detailed in the following reconciliation. Adjusted EBITDA is presented because 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. We believe Adjusted EBITDA is also used by and is useful to investors and other users of our financial statements in evaluating our operating performance because it provides them with an additional tool to compare business performance across companies and across periods. We believe that EBITDA is widely used by investors to measure a company’s operating performance without regard to items such as interest expense, taxes, depreciation and amortization, which can vary substantially from company to company depending upon accounting methods and book value of assets, capital structure and the method by which assets were acquired. 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 and is not necessarily comparable to similarly titled measures reported by other companies.

Adjusted Recurring Free Cash Flow represents net income before interest, taxes, depreciation and amortization, as adjusted, less operating lease payments, major maintenance expense and maintenance capital expenditures, net cash interest, cash taxes, working capital and other adjustments. Adjusted Recurring Free Cash Flow is a performance measure and is not intended to represent net income (loss), the most directly comparable U.S. GAAP measure, or liquidity and is not necessarily comparable to similarly titled measures reported by other companies.

Commodity Margin Reconciliation

The following table reconciles our Commodity Margin to its U.S. GAAP results for the three months ended June 30, 2012 and 2011 (in millions):

	Three Months Ended June 30, 2012					
	West	Texas	North	Southeast	Consolidation And Elimination	Total
Commodity Margin [1]	$ 210	$ 145	$ 181	$ 73	$ —	$ 609
Add: Mark-to-market commodity activity, net and other [2][3]	(76)	(217)	(3)	(42)	(6)	(344)
Less:						
Plant operating expense	112	72	58	36	(7)	271
Depreciation and amortization expense	49	34	34	22	(1)	138
Sales, general and other administrative expense	6	13	8	7	1	35
Other operating expenses [4]	9	1	6	2	1	19
(Income) from unconsolidated investments in power plants	—	—	(5)	—	—	(5)
Income (loss) from operations	$ (42)	$ (192)	$ 77	$ (36)	$ —	$ (193)

	Three Months Ended June 30, 2011					
	West	Texas	North	Southeast	Consolidation And Elimination	Total
Commodity Margin [1]	$ 236	$ 128	$ 184	$ 59	$ —	$ 607
Add: Mark-to-market commodity activity, net and other [2][3]	11	27	(5)	—	(9)	24
Less:						
Plant operating expense	116	63	47	41	(6)	261
Depreciation and amortization expense	42	35	33	22	(1)	131
Sales, general and other administrative expense	8	13	6	6	1	34
Other operating expenses [4]	11	3	9	2	(5)	20
Loss from unconsolidated investments in power plants	—	—	2	—	—	2
Income (loss) from operations	$ 70	$ 41	$ 82	$ (12)	$ 2	$ 183

Commodity Margin Reconciliation (continued)

The following table reconciles our Commodity Margin to its U.S. GAAP results for the six months ended June 30, 2012 and 2011 (in millions):

	Six Months Ended June 30, 2012					
	West	Texas	North	Southeast	Consolidation And Elimination	Total
Commodity Margin [1]	$ 418	$ 254	$ 325	$ 129	$ —	$ 1,126
Add: Mark-to-market commodity activity, net and other [2][5]	(40)	(183)	9	(32)	(14)	(260)
Less:						
Plant operating expense	193	140	103	69	(13)	492
Depreciation and amortization expense	99	69	67	45	(2)	278
Sales, general and other administrative expense	14	24	14	15	1	68
Other operating expenses [4]	20	3	15	3	(1)	40
(Income) from unconsolidated investments in power plants	—	—	(14)	—	—	(14)
Income (loss) from operations	$ 52	$ (165)	$ 149	$ (35)	$ 1	$ 2

	Six Months Ended June 30, 2011					
	West	Texas	North	Southeast	Consolidation And Elimination	Total
Commodity Margin [1]	$ 469	$ 195	$ 319	$ 113	$ —	$ 1,096
Add: Mark-to-market commodity activity, net and other [2][5]	16	(33)	(1)	(4)	(15)	(37)
Less:						
Plant operating expense	203	143	92	74	(13)	499
Depreciation and amortization expense	88	65	66	45	(2)	262
Sales, general and other administrative expense	19	23	12	11	1	66
Other operating expenses [4]	19	3	16	3	(3)	38
(Income) from unconsolidated investments in power plants	—	—	(7)	—	—	(7)
Income (loss) from operations	$ 156	$ (72)	$ 139	$ (24)	$ 2	$ 201

(1) Our North segment includes Commodity Margin related to Riverside Energy Center, LLC of $24 million and $22 million for three months ended June 30, 2012 and 2011 , respectively, and $32 million and $31 million for the six months ended June 30, 2012 and 2011 , respectively.

(2) Mark-to-market commodity activity represents the change in the unrealized portion of our mark-to-market activity, net, included in operating revenues and fuel and purchased energy expense on our Consolidated Condensed Statements of Operations. The increase in unrealized mark-to-market losses for the three and six months ended June 30, 2012, was primarily driven by the impact of a near term increase in forward power prices and corresponding Market Heat Rate expansion in the ERCOT region during the last several days of June 2012.

(3) Includes $(1) million and $4 million of lease levelization and $3 million and $1 million of amortization expense for the three months ended June 30, 2012 and 2011, respectively.

(4) Excludes $2 million of RGGI compliance and other environmental costs for both the three months ended June 30, 2012 and 2011 , and $5 million and $4 million for the six months ended June 30, 2012 and 2011 , respectively, which are components of Commodity Margin.

(5) Includes $(9) million and $4 million of lease levelization and $7 million and $1 million of amortization expense for the six months ended June 30, 2012 and 2011 , respectively.

Consolidated Adjusted EBITDA Reconciliation

In the following table, we have reconciled our Adjusted EBITDA and Adjusted Recurring Free Cash Flow to our net loss attributable to Calpine for the three and six months ended June 30, 2012 and 2011, as reported under U.S. GAAP.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in millions)			
Net loss attributable to Calpine	$ (329)	$ (70)	$ (338)	$ (367)
Net income attributable to the noncontrolling interest	—	—	—	1
Income tax expense (benefit)	(52)	18	(58)	(65)
Debt extinguishment costs and other (income) expense, net	6	8	20	108
Loss on interest rate derivatives	—	37	14	146
Interest expense, net	182	190	364	378
Income from operations	$ (193)	$ 183	$ 2	$ 201
Add:				
Adjustments to reconcile income from operations to Adjusted EBITDA:				
Depreciation and amortization expense, excluding deferred financing costs [(1)]	138	131	279	263
Major maintenance expense	81	76	127	136
Operating lease expense	8	9	17	17
Unrealized (gain) loss on commodity derivative mark-to-market activity	346	(26)	268	39
Adjustments to reflect Adjusted EBITDA from unconsolidated investments [(2)(3)]	9	13	16	21
Stock-based compensation expense	7	7	13	12
Loss on dispositions of assets	2	4	4	9
Acquired contract amortization	3	1	7	1
Other	2	8	(5)	10
Total Adjusted EBITDA	$ 403	$ 406	$ 728	$ 709
Less:				
Lease payments	8	9	17	17
Major maintenance expense and capital expenditures [(4)]	109	152	255	263
Cash interest, net [(5)]	190	195	381	393
Cash taxes	7	6	11	10
Other	2	3	4	6
Adjusted Recurring Free Cash Flow [(6)]	$ 87	$ 41	$ 60	$ 20
Weighted average shares of common stock outstanding (diluted, in thousands)	471,444	486,411	474,775	486,334
Adjusted Recurring Free Cash Flow Per Share	$ 0.19	$ 0.08	$ 0.13	$ 0.04

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

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

(3) Adjustments to reflect Adjusted EBITDA from unconsolidated investments include unrealized (gain) loss on mark-to-market activity of nil for both the three and six months ended June 30, 2012 and 2011.

(4) Includes $84 million and $131 million in major maintenance expense for the three months and six months ended June 30, 2012, respectively, and $25 million and $124 million in maintenance capital expenditures for the three months and six months ended June 30, 2012, respectively. Includes $80 million and $138 million in major maintenance expense for the three months and six months ended June 30, 2011, respectively, and $72 million and $125 million in maintenance capital expenditures for the three months and six months ended June 30, 2011, respectively.

(5) Includes commitment, letter of credit and other bank fees from both consolidated and unconsolidated investments, net of capitalized interest and interest income.

(6) Excludes increase in working capital of $56 million and decrease in working capital of $20 million for the three months and six months ended June 30, 2012, respectively, and a decrease in working capital of $45 million and $145 million for the three months and six months ended June 30, 2011, respectively. Adjusted Recurring Free Cash Flow, as reported, excludes changes in working capital, such that it is calculated on the same basis as our guidance.

Consolidated Adjusted EBITDA Reconciliation (continued)

In the following table, we have reconciled our Adjusted EBITDA to our Commodity Margin, both of which are non-GAAP measures, for the three and six months ended June 30, 2012 and 2011. Reconciliations for both Adjusted EBITDA and Commodity Margin to comparable U.S. GAAP measures are provided above.

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	2011	2012	2011
	(in millions)			
Commodity Margin	$ 609	$ 607	$ 1,126	$ 1,096
Other revenue	3	3	6	7
Plant operating expense [1]	(181)	(176)	(351)	(346)
Sales, general and administrative expense [2]	(30)	(27)	(60)	(55)
Other operating expense [3]	(10)	(10)	(21)	(19)
Adjusted EBITDA from unconsolidated investments in power plants [4]	14	10	30	27
Other	(2)	(1)	(2)	(1)
Adjusted EBITDA	$ 403	$ 406	$ 728	$ 709

(1) Shown net of major maintenance expense, stock-based compensation expense and non-cash loss on dispositions of assets.
(2) Shown net of stock-based compensation expense.
(3) Shown net of operating lease expense, amortization and RGGI compliance and other environmental costs.
(4) Amount is comprised of income from unconsolidated investments in power plants, as well as adjustments to reflect Adjusted EBITDA from unconsolidated investments.

Adjusted EBITDA and Adjusted Recurring Free Cash Flow Reconciliation for Guidance

Full Year 2012 Range:	Low	High
	(in millions)	
GAAP Net Income (Loss) [1]	$ —	$ 100
Plus:		
Debt extinguishment costs	12	12
Loss on interest rate derivatives	14	14
Interest expense, net of interest income	765	765
Depreciation and amortization expense	575	575
Major maintenance expense	195	195
Operating lease expense	35	35
Other [2]	104	104
Adjusted EBITDA	$ 1,700	$ 1,800
Less:		
Operating lease payments	35	35
Major maintenance expense and maintenance capital expenditures [3]	350	350
Accelerated parts purchases to support upgrades [4]	30	30
Recurring cash interest, net [5]	770	770
Cash taxes	10	10
Other	5	5
Adjusted Recurring Free Cash Flow	$ 500	$ 600
Non-recurring interest rate swap payments [6]	$ (156)	$ (156)

(1) For purposes of Net Income (Loss) guidance reconciliation, unrealized mark-to-market adjustments are assumed to be nil.
(2) Other includes stock-based compensation expense, adjustments to reflect Adjusted EBITDA from unconsolidated investments, income tax expense and other items.
(3) Includes projected major maintenance expense of $185 million and maintenance capital expenditures of $165 million. Capital expenditures exclude major construction and

development projects. 2012 figures exclude amounts to be funded by project debt.

(4) Incremental impact on 2012 maintenance capital expenditures related to acceleration of future turbine upgrades into 2012 and deferral of use of on-hand parts to post-2012 periods.

(5) Includes fees for letters of credit, net of interest income.

(6) Interest payments related to legacy LIBOR hedges associated with floating rate First Lien Credit Facility, which has been refinanced.

OPERATING PERFORMANCE METRICS

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

	Three Months Ended June 30,		Six Months Ended June 30,	
	2012	**2011**	**2012**	**2011**
Total MWh generated (in thousands) [(1)]	26,681	19,394	54,736	37,521
West	6,191	3,454	14,394	9,649
Texas	9,089	7,867	18,232	13,186
Southeast	6,201	4,286	11,923	8,571
North	5,200	3,787	10,187	6,115
Average availability	86.4%	84.8%	88.4%	86.8%
West	81.6%	75.9%	87.6%	83.9%
Texas	88.3%	89.1%	87.0%	84.3%
Southeast	90.8%	85.3%	92.5%	89.8%
North	85.4%	88.4%	87.3%	89.7%
Average capacity factor, excluding peakers	51.0%	37.6%	53.0%	37.2%
West	45.0%	25.3%	52.7%	35.7%
Texas	59.3%	51.6%	59.6%	43.5%
Southeast	51.8%	36.0%	50.3%	37.0%
North	45.6%	34.6%	46.4%	29.6%
Steam adjusted heat rate (mmbtu/kWh)	7,391	7,451	7,329	7,411
West	7,366	7,755	7,233	7,495
Texas	7,150	7,204	7,115	7,224
Southeast	7,309	7,322	7,291	7,310
North	7,991	7,985	7,903	7,888

(1) Excludes generation from unconsolidated power plants and power plants owned but not operated by us.