CALPINE®
NYSE CPN

A GENERATION AHEAD, *today*

First Quarter 2012
Investor Update Conference Call

April 27, 2012

CLEAN MODERN EFFICIENT FLEXIBLE POWER GENERATION

Safe Harbor Statement

Forward-Looking Statements

The information contained in this presentation includes certain estimates, projections and other forward-looking information that reflect Calpine's current views with respect to future events and financial performance. These estimates, projections and other forward-looking information are based on assumptions that Calpine believes, as of the date hereof, are reasonable. Inevitably, there will be differences between such estimates and actual results, and those differences may be material.

There can be no assurance that any estimates, projections or forward-looking information will be realized.

All such estimates, projections and forward-looking information speak only as of the date hereof. Calpine undertakes no duty to update or revise the information contained herein other than as required by law.

You are cautioned not to place undue reliance on the estimates, projections and other forward-looking information in this presentation as they are based on current expectations and general assumptions and are subject to various risks, uncertainties and other factors, including those set forth in Calpine's Annual Report on Form 10-K for the year ended December 31, 2011, and Quarterly Report on Form 10-Q for the quarter ended March 31, 2012, and in other documents that Calpine files with the SEC. Many of these risks, uncertainties and other factors are beyond Calpine's control and may cause actual results to differ materially from the views, beliefs and estimates expressed herein. Calpine's reports and other information filed with the SEC, including the risk factors identified in its Annual Report on Form 10-K for the year ended December 31, 2011, can be found on the SEC's website at www.sec.gov and on Calpine's website at www.calpine.com.

Reconciliation to U.S. GAAP Financial Information

The following presentation includes certain "non-GAAP financial measures" as defined in Regulation G under the Securities Exchange Act of 1934, as amended. Schedules are included herein that reconcile the non-GAAP financial measures included in the following presentation to the most directly comparable financial measures calculated and presented in accordance with U.S. GAAP.

Agenda

- Welcome and Safe Harbor

  Bryan Kimzey
  Vice President, Investor Relations

- CEO Review

  Jack Fusco
  President, Chief Executive Officer

- Operations Review

  Thad Hill
  EVP, Chief Operating Officer

- Financial Review

  Zamir Rauf
  EVP, Chief Financial Officer

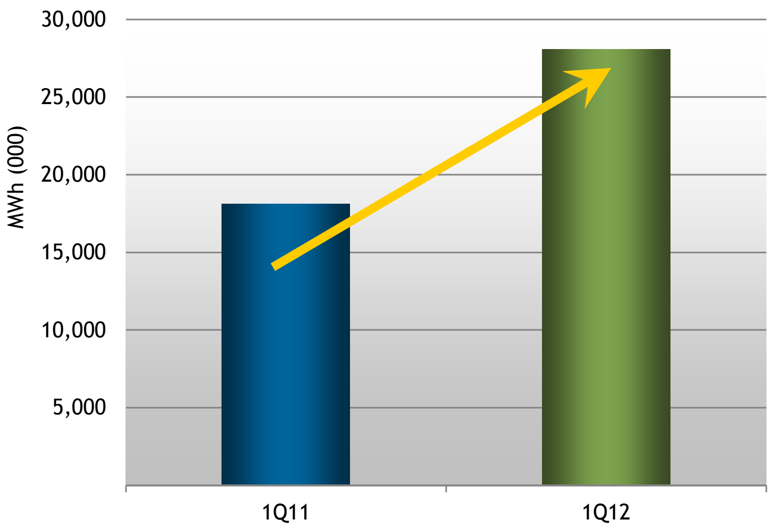
- Q&A

1Q12 Highlights

Key Messages:

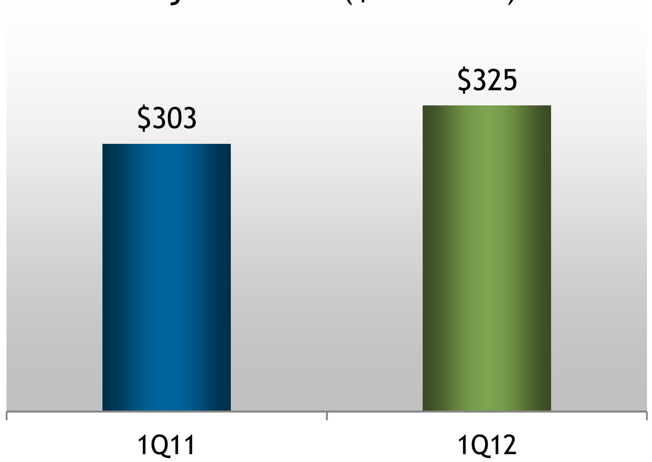
- Produced record-breaking 1Q plant operating results
  - 29 billion kWh (↑ 52% vs. 1Q11)
  - Starting reliability: 98.1%
  - Forced outage factor: 1.1%
  - First ever "No Lost-Time Incidents" quarter
- Delivered solid financial performance
  - Adj. EBITDA[1]: $325 million (↑ 7% vs. 1Q11)
  - Controlled costs
- Continued pursuit of disciplined growth
  - Advancing 800+ MW of CCGT development opportunities in ERCOT and PJM
  - Constructing nearly 800 MW of contracted CCGTs in CA
  - Oneta Energy Center: 20-year PPA with Western Farmers Elec. Co-Op
- Achieved favorable regulatory outcomes
  - WPSC approval of customer's Riverside purchase
  - LA PSC approval of Carville PPA
  - CPUC approval of Sutter proposal

Significant Incremental Volume Despite Mild Weather



Solid Financial Performance

Adj. EBITDA[1] ($ millions)



[1] A non-GAAP financial measure. Reconciliations of Adjusted EBITDA to Net Loss, the most comparable U.S. GAAP measure, are included in the appendix.

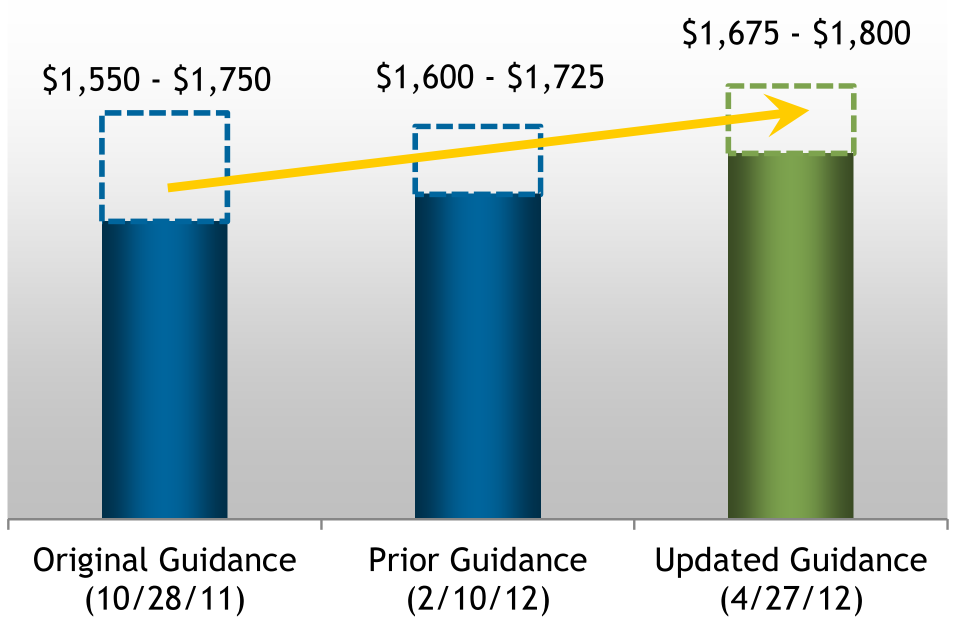
Raising 2012 Guidance

Key Drivers for 1Q and FY12

- Significant increase in 1Q volume, despite mild weather
  - Incremental on-peak MWh outside of "super-peak" periods
  - Incremental off-peak MWh, though at narrow margins
- Opportunity for additional incremental volume in 2012 (primarily 2Q & 4Q)
  - Low natural gas price environment expected to persist
  - Volatility represents further upside
- Some headwinds remain
  - Lower regulatory capacity payments in 2012 (vs. 2011)
  - Expiration of certain contracts
  - Lower absolute power prices at Geysers

Raising Guidance

Adj. EBITDA[1] ($ millions)



	Original Guidance (10/28/11)	Prior Guidance (2/10/12)	Updated Guidance (4/27/12)
Adj. Recurring Free Cash Flow [1] ($ millions)	*$375 - $575*	*$425 - $550*	*$470 - $595*

[1] A non-GAAP financial measure. Reconciliations of Adjusted EBITDA and Adjusted Recurring Free Cash Flow to Net Income (Loss), the most comparable U.S. GAAP measure, are included in the appendix.

Updating Capital Allocation Outlook

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1Q Capital Allocation Checklist:

- ☑ Clarity on 2012: Shaping up favorably given low gas price environment
  - Strong liquidity
  - Increasing guidance
- ☑ Terminated legacy interest rate swaps
- ☑ Advancing development of 800+ MW
- ☑ Riverside divestiture remains on target
- ☑ Significant projected excess cash balance remaining

Doubling Share Repurchase:

Original Program

$300 million

- Completed: $124 million
- Remaining: $176 million

1Q12 strategy too conservative → Missed opportunity; Re-evaluating program execution

+

Update: $300 million

=

Expanded Program

$600 million

- Completed: $124 million
- Total Remaining: $476 million

Disciplined approach to creating long-term shareholder value

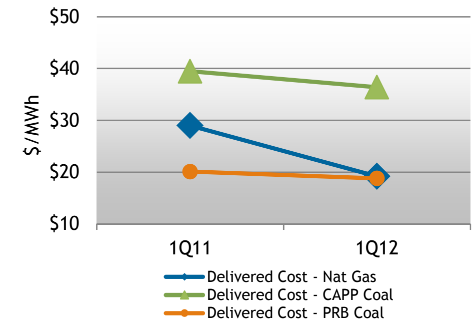
Trends Continuing to Favor Calpine

Power Markets

- ERCOT: Summer 2012-2014 heat rates contango
- PJM: Summer 2012 heat rates at all-time high
- CA: Drier weather pattern; Nuclear outage
- Southeast: Continued interest in long-term contracts and/or asset purchases

Fuel Cost Fundamentals

- Coal: Recent price pressure, though still above natural gas
- Natural gas: Lowest price in 10 years; remain bearish 2012
  - Potential for full storage in 3Q
- *Coal-to-gas spread is economic driver*



State Action to Improve Competitive Markets

- ERCOT: Implementing rule changes to signal scarcity
- PJM: Discussing multi-year capacity product
- CA: Advancing Long-term Procurement Plan discussions to level playing field
  - Sutter as catalyst
- Southeast: Entergy to join MISO

Stricter Environmental Regulation

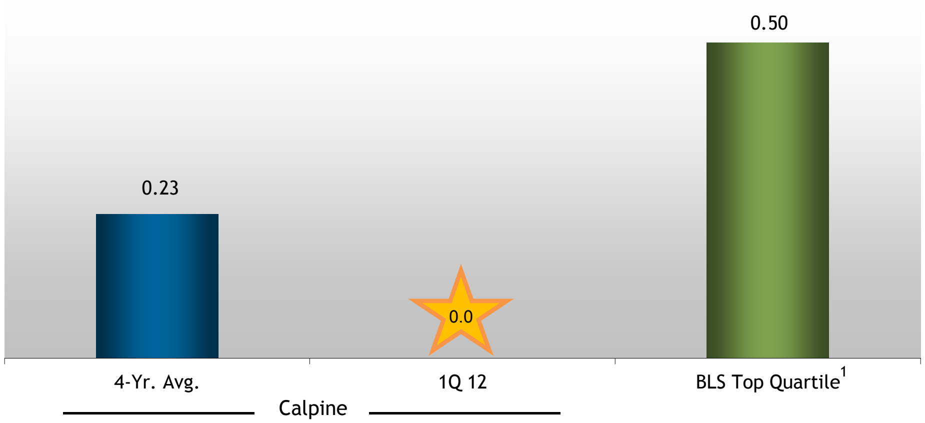
- EPA: Just the beginning…
  - CSAPR
  - MATS
  - GHG NSPS
  - Coal combustion byproducts
  - 316(b) (OTC)
- State initiatives

Notes for chart above: Commodities price sources: NYMEX, Calpine data. Gas prices represent SONAT-basis gas. Assumes production heat rates of 10,000 btu/kWh (coal) and 7,000 btu/kWh (gas) and $22/ton CAPP and PRB coal transport costs.

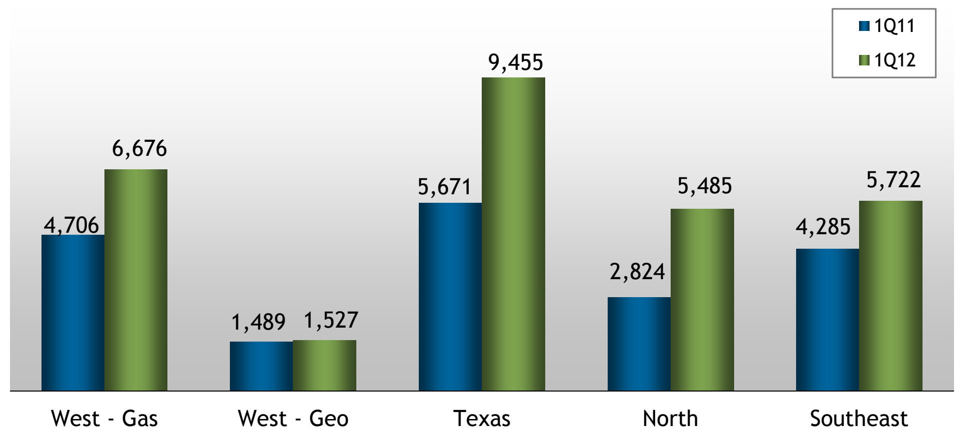
OPERATIONS REVIEW

Focused on Best-in-Class Operations

Employee Lost-Time Incident Rate
Record first quarter safety performance

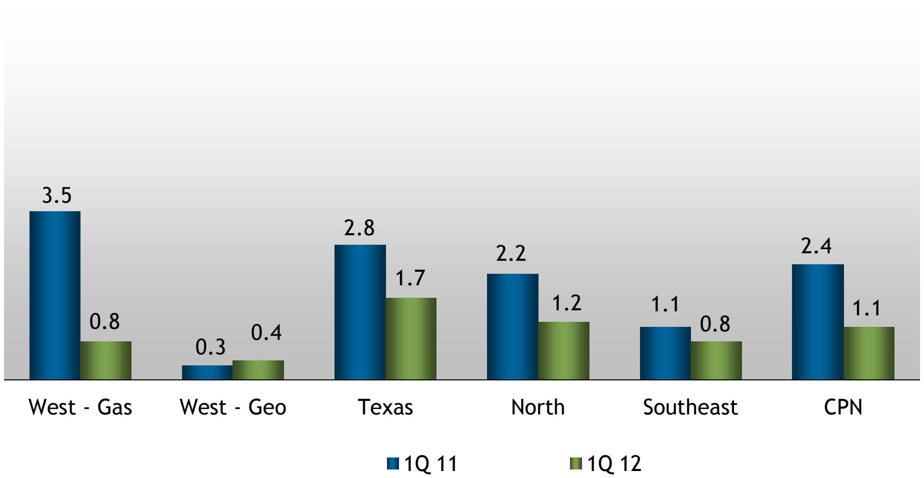


Generation in Key Markets (000 MWh)[2]
Generated 29 million MWh - 52% increase year-over-year

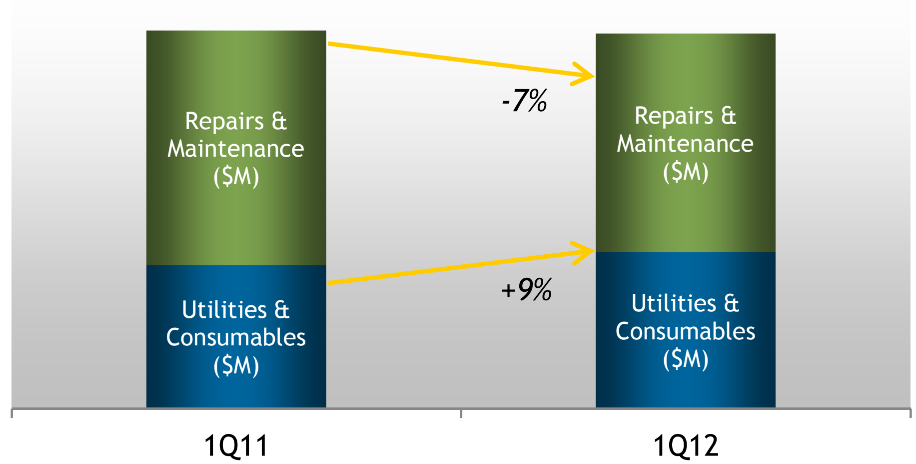


1Q12 CCGT Cap. Factor:	West - Gas	West - Geo	Texas	North	Southeast
	56%	n/a	60%	47%	49%

Forced Outage Factor (FOF, %)
Significant improvement year-over-year; well below 2.5% target



Controlling Costs while Increasing Volumes
Plant OpEx[3] flat: Higher consumables offset by lower repairs

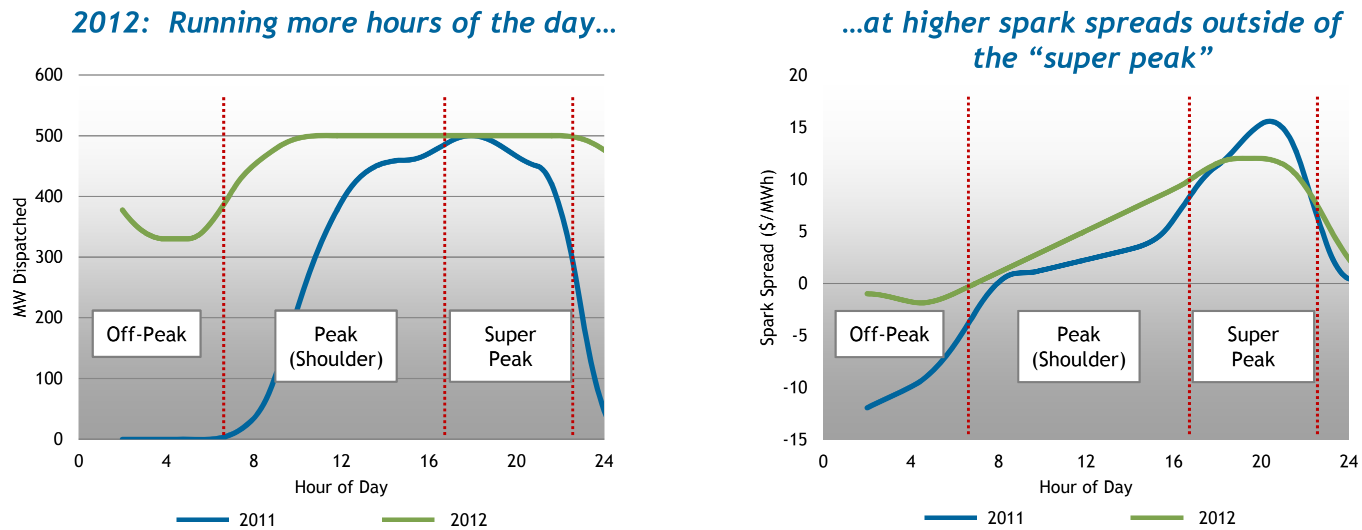


[1] NAICS 221112 – Fossil Fuel Electric Power Generation 1,000+ Employees. Most recent First Quartile data available (2006).
[2] As compared to our SEC filings, generation shown here includes net interest in generation from our deconsolidated power plants and plants owned but not operated by us.
[3] Plant Operating Expense (POX), excluding major maintenance expense, non-cash stock-based compensation and non-cash loss on disposal of assets. Note that graph represents certain components of POX; other items in POX include personnel costs, fixed costs, and other controllable costs.

Incremental Generation vs. Incremental Margin: A Closer Look

Dramatically Different Dispatch

Illustrative Hourly Operating Statistics: 2011 v 2012



Note: Illustrative day's operation in March based upon actual operating data for 500 MW combined-cycle plant in Texas in 2011 and 2012.

Understanding the Dynamics

	The "Not So Good" News		*The Really Good News*
On-Peak Dispatch	• Lower super-peak margins, given mild weather	*but…*	• Higher volume and margin on non-super-peak hours
Off-Peak Dispatch	• Incremental volume, though at thin margins	*but…*	• Higher margins on must-run cogeneration obligations (esp. in Texas)

Net impact: Approx. $40 million incremental margin

Energy Margin[1]: Positioned to Respond to Favorable Secular Trends

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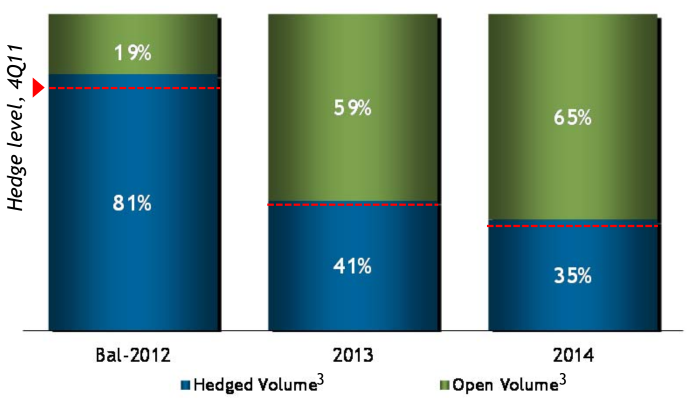
Energy Hedge Profile[2]

$ Energy Margin[1,2] as % of Total Commodity Margin (by year):

81% *77%* *78%*

Use in conjunction with modeling tips in appendix

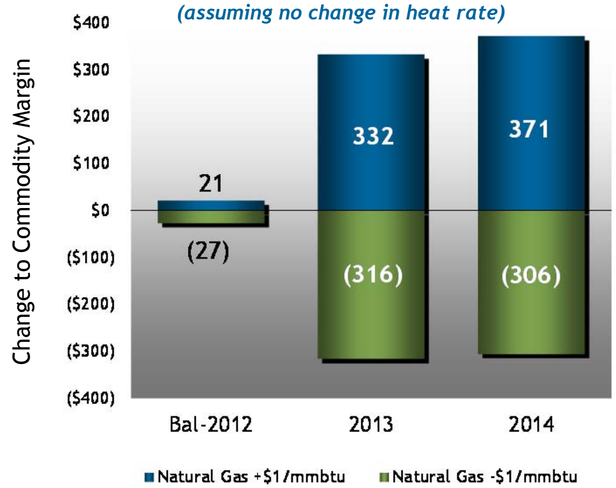


	2012	2013	2014
Hedged Margin ($/MWh)[2]	$19	$28	$26
Avg. MW in Operation [2,4]	28,000	28,136	28,192

Sensitivities

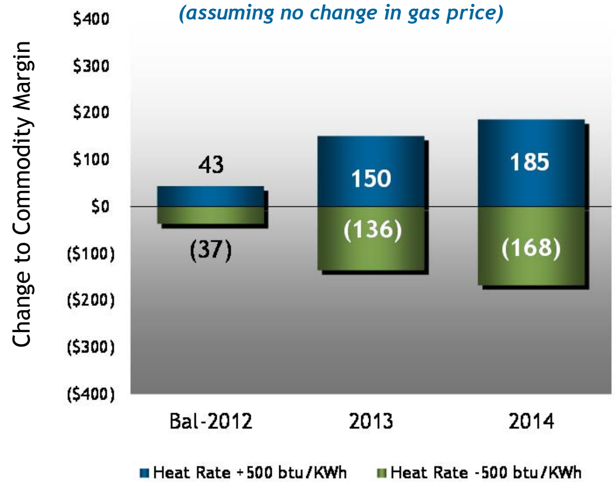
Natural Gas Price Sensitivity[2]

(assuming no change in heat rate)



Market Heat Rate Sensitivity[2]

(assuming no change in gas price)



Summary

- Material (but not absolute) upside/exposure to Texas summer
- Effective gas position
  - 2012: Remain short
  - 2013: Modestly short
  - 2014: Neutral
- Reminder:
  - Market heat rates tend to show inverse relationships with gas prices in some markets
  - ±500 btu/kWh sensitivity shown here, but inverse relationship historically much stronger at lower gas prices
  - Refer to 4Q11 earnings presentation (lower right chart on slide 9) for illustration of relationship as applied to CPN fleet

[1] Energy Margin + Regulatory & Other Margin = Total Commodity Margin.

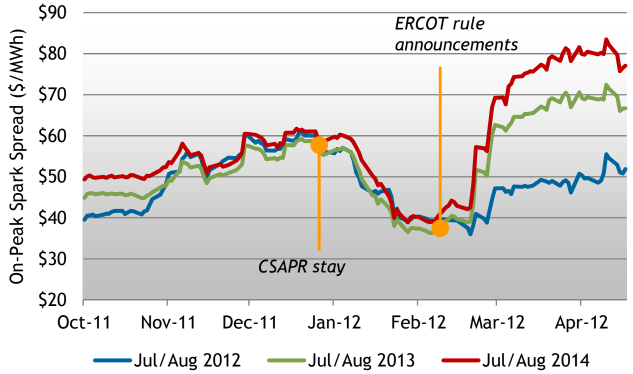
[2] Estimated as of 04/13/12. Hedged margin excludes unconsolidated projects and includes the current mark-to-market adjustments of all executed transactions. Changing market heat rates will change delta volumes and gas price exposures. Sensitivities are assumed to occur across the portfolio and the sensitivities on strategic options only capture intrinsic value.

[3] Volumes are on a delta hedge basis. Delta volumes are the expected volume based on the probability of economic dispatch at a future date based on current market prices for that future date. This is lower than the notional volume, which is plant capacity, less known performance and operating constraints. Volumes assume sale of Riverside and addition of Los Esteros and 75% of Russell City in 2013. 2014 volumes do not yet include announced expansions of Deer Park and Channel, pending commencement of construction.

[4] Represents Calpine's forecasted average annual capacity of net ownership interest with peaking capacity. Capacity additions/deletions are reflected in anticipated month of completion and do not include Deer Park or Channel expansions, pending commencement of construction.

Key Developments to Watch

ERCOT:
Is Scarcity Price Showing?

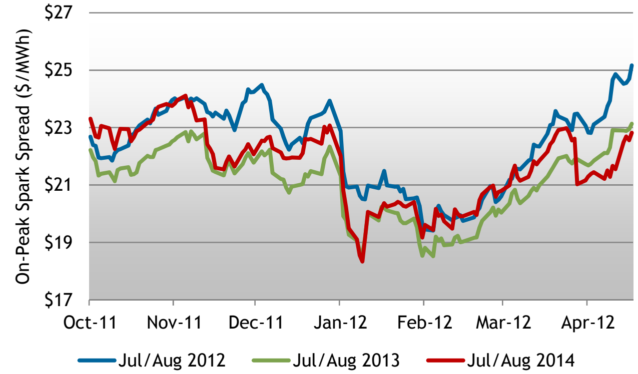


Source: Broker data, Calpine. Assumes 7,000 btu/kWh heat rate.

Key Issues:

- ↑ Rule changes to signal scarcity
  - Non-Spin Reserve pricing
  - Operating reserves / Reliability services priced at offer cap
  - To come: ↑ offer cap and power balance penalty curve limit
- ↑ ERCOT SARA announcement: Energy Emergency Alerts expected Summer 2012

PJM:
What Happens to Energy and Capacity Prices?



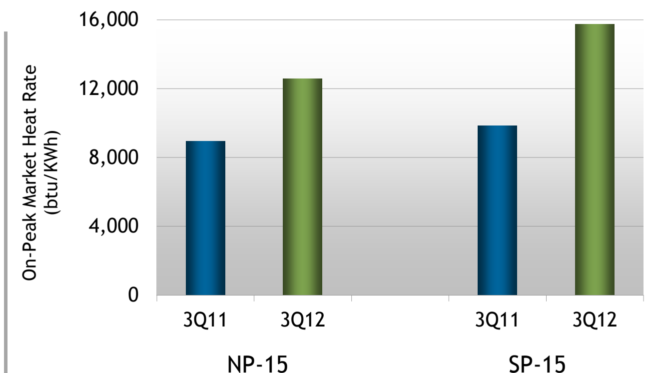
Source: Broker data, Calpine. Assumes 8,500 btu/kWh heat rate. PJM-W shown.

Capacity Prices:

2015/2016 RPM Auction Outlook

- ↑ Higher CONE / Higher MOPR
- ↑ Elimination of DR double counting
- ↑ EPA / HEDD rules
- ○ Significant state procurements unlikely
- ↓ Lower demand
- ↓ Increased MAAC & EMAAC imports
- ? DR growth

California:
Return to Normal Weather?



Source: Broker data, Calpine. 3Q12 as of 4/20/12.

Short-Term Issues:

- ↑ Less hydro, though gap closing
- ↑ Normalized weather
- ↑ Nuclear outage
- ↑ CO_2 (starting in 2013)
- ? Sutter

Long-Term Issues:

- ↑ Market reform to compensate fossil generators

Pursuing Financially Disciplined Growth

	ERCOT		*PJM*
	Deer Park Expansion	***Channel Expansion***	***Garrison***
Incremental CCGT Capacity	• 260 MW[1]	• 260 MW[1]	• 309 MW (Phase I)
Expected COD	• June 2014	• June 2014	• June 2015
Economics[2]	• Less than $550/kW • *Plus* 5% plantwide efficiency improvement	• Less than $550/kW • *Plus* 17% plantwide efficiency improvement	• Less than $800/kW
Sources of Economic Advantage	• Legacy CT • Existing oversized ST • Existing infrastructure	• Legacy CT • Existing oversized ST • Existing infrastructure	• Legacy CT • Gray market ST • De minimis PJM upgrade costs given queue position
Key Milestones (Expected Timing)	• 3Q12: Interconnection agreement • 4Q12: Air permits	• 4Q12: Interconnection agreement • 4Q12: Air permits	• 2Q12: Capacity auction • 3Q12: Land use/air permits • 4Q12: Interconnection agreement

Conservatively adding capacity at 5-6x EBITDA

CT: Combustion turbine. ST: Steam turbine.

[1] Represents incremental baseload capacity at annual average conditions. Incremental summer peaking capacity is approximately 200 MW per unit, supplemented by incremental efficiencies across the balance of the plant.

[2] $/kW shown in 2012 nominal dollars (i.e., "overnight costs").

FINANCIAL REVIEW

Financial Overview

($ millions)

1Q12 Objectives:

- Deliver on financial guidance
  - ✓ Achieved solid 1Q12 financial performance
  - ✓ Raising 2012 guidance
- Simplify capital structure
  - ✓ Terminated legacy interest rate swaps
  - ✓ Unwound Agnews sale-leaseback financing
  - ✓ Closed on Calif. Peaker equity purchase

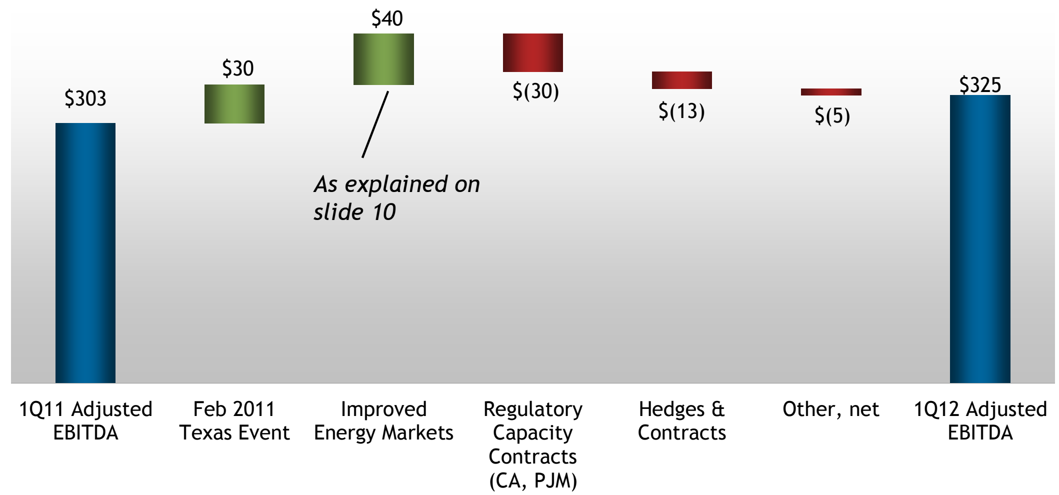
Capital Allocation Objectives:

- Maintain strong liquidity
- Target 4.5x Net Debt / Adj. EBITDA[1]
- Fund near-term growth projects
- Continue share repurchase program

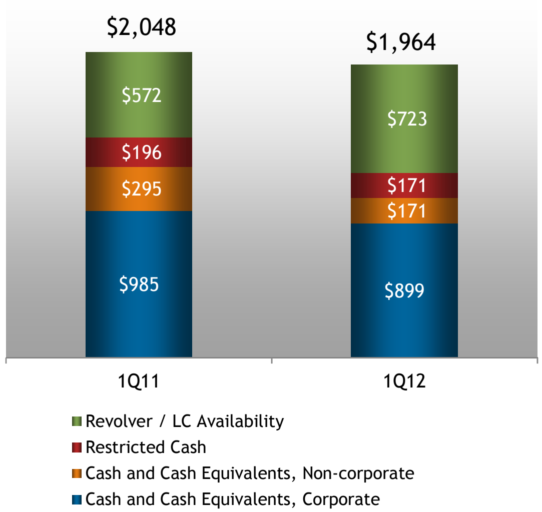
Note: Effective 1Q12, discontinuing application of hedge accounting treatment for commodity derivatives
- – <u>*NO*</u> impact to Adjusted EBITDA[1] or Adjusted Recurring Free Cash Flow[1]

Solid 1Q Financial Performance

Adjusted EBITDA[1] Drivers

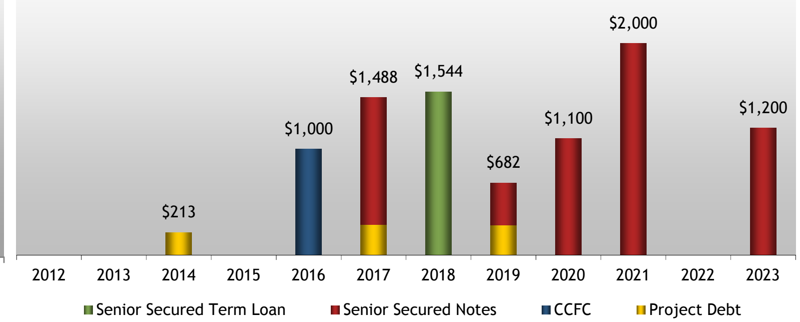


Maintained Strong Liquidity



No Significant Near Term Maturities[2]

Plus:
- *Flexible covenants*
- *No corporate maturities >$2B in any year*



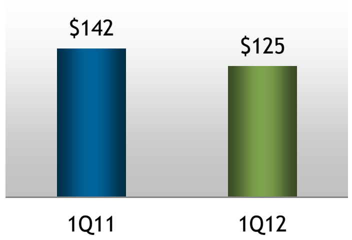
[1] A non-GAAP financial measure. Reconciliation sof Adjusted EBITDA and Adjusted Recurring Free Cash Flow to Net Loss, the most comparable U.S. GAAP measure, are included in the appendix.
[2] The debt maturity schedules shown here are not prepared on a U.S. GAAP basis and do not conform to the debt maturity schedule presented in Calpine's Form 10-K. (Refer to the Form 10-K for further information regarding U.S. GAAP-basis debt maturities). Assumptions used in debt maturity charts shown here are as follows: (i) excludes letter of credit facilities; (ii) maturity balances assume cash sweeps; and (iii) all other debt maturities are paid from operating cash flows at the project level. Project debt in 2019 represents projected balance for OMEC. Put price in the PPA approximates the projected debt balance.

Regional Adjusted EBITDA: 1Q 2012 vs. 2011

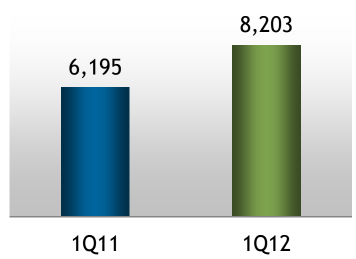
($ millions, 000 MWh)

West Region

Adjusted EBITDA[1]



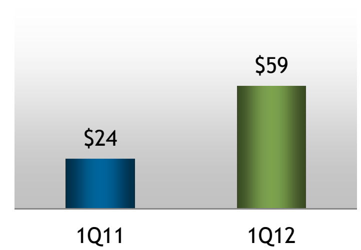
Generation[2]



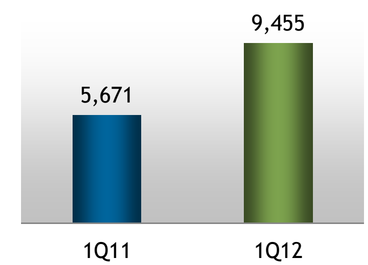
- Lower Commodity Margin[1]
  - – Contract expiration: Lower PPA and RA revenues
  - – Sutter: Idle during 1Q12 (no RA contract)
  - – Lower contribution from Geysers hedges
  - \+ Higher generation: Higher spark spreads (less hydro)

Texas Region

Adjusted EBITDA[1]



Generation[2]

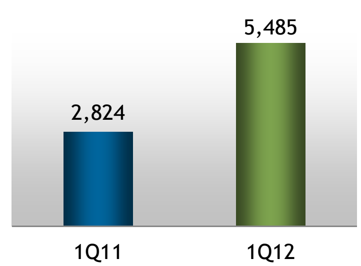


- Higher Commodity Margin[1]
  - \+ Extreme winter weather event in 1Q11 (+$30M)
  - \+ Higher generation: Low natural gas prices
  - – Lower on-peak and "super-peak" prices: mild weather

North Region

Adjusted EBITDA[1]

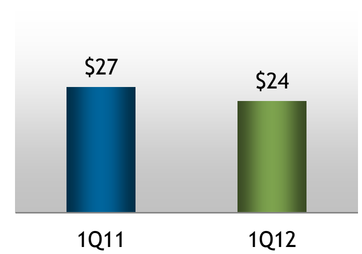
Generation[2]



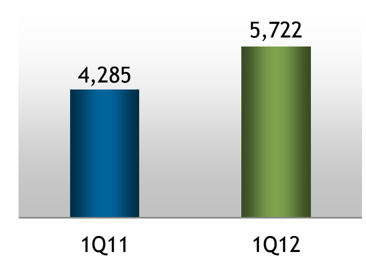
- Higher Commodity Margin[1]
  - \+ Full quarter of York Energy Center
  - \+ Higher generation: Low natural gas prices
  - \+ Fixed-price contracts (benefit from spark spread expansion)
  - – Lower RPM capacity payments in 1Q12 (-$22M)
  - – No high-margin weather events in 1Q12

Southeast Region

Adjusted EBITDA[1]



Generation[2]



- Higher Commodity Margin[1]
  - \+ Higher generation: Increased dispatch at contracted plants
  - – PPA expiration

[1] A non-GAAP financial measure. Reconciliations of Commodity Margin to Income from Operations and of Adj. EBITDA to Net Loss, the most comparable U.S. GAAP measure, are included in the appendix.
[2] As compared to our SEC filings, generation shown here includes net interest in generation from deconsolidated projects and plants owned but not operated.

2012 Guidance Update

($ millions)

	Prior Guidance (Feb 2012)	*Updated Guidance (Apr 2012)*
Adjusted EBITDA[1]	**$1,600 - 1,725**	**$1,675 - 1,800**
Less:		
Operating lease payments	35	35
Major maintenance expense & CapEx[2]	350	350
Accelerated parts purchases to support upgrades	–	30
Recurring cash interest, net[3]	770	770
Cash taxes	10	10
Other	10	10
Adjusted Recurring Free Cash Flow[1]	**$425 - 550**	**$470 - 595**
Non-recurring interest rate swap payments[4]	$(150)	$(156)
Growth CapEx (net of funding)	$(10)	$(100)
Riverside sale proceeds[5]	$392	$392

One-time incremental impact on 2012 maintenance CapEx: Accelerating future upgrades into 2012 and deferring use of on-hand parts to post-2012 periods

Now includes expenditures associated with Deer Park and Channel expansions and Garrison greenfield construction

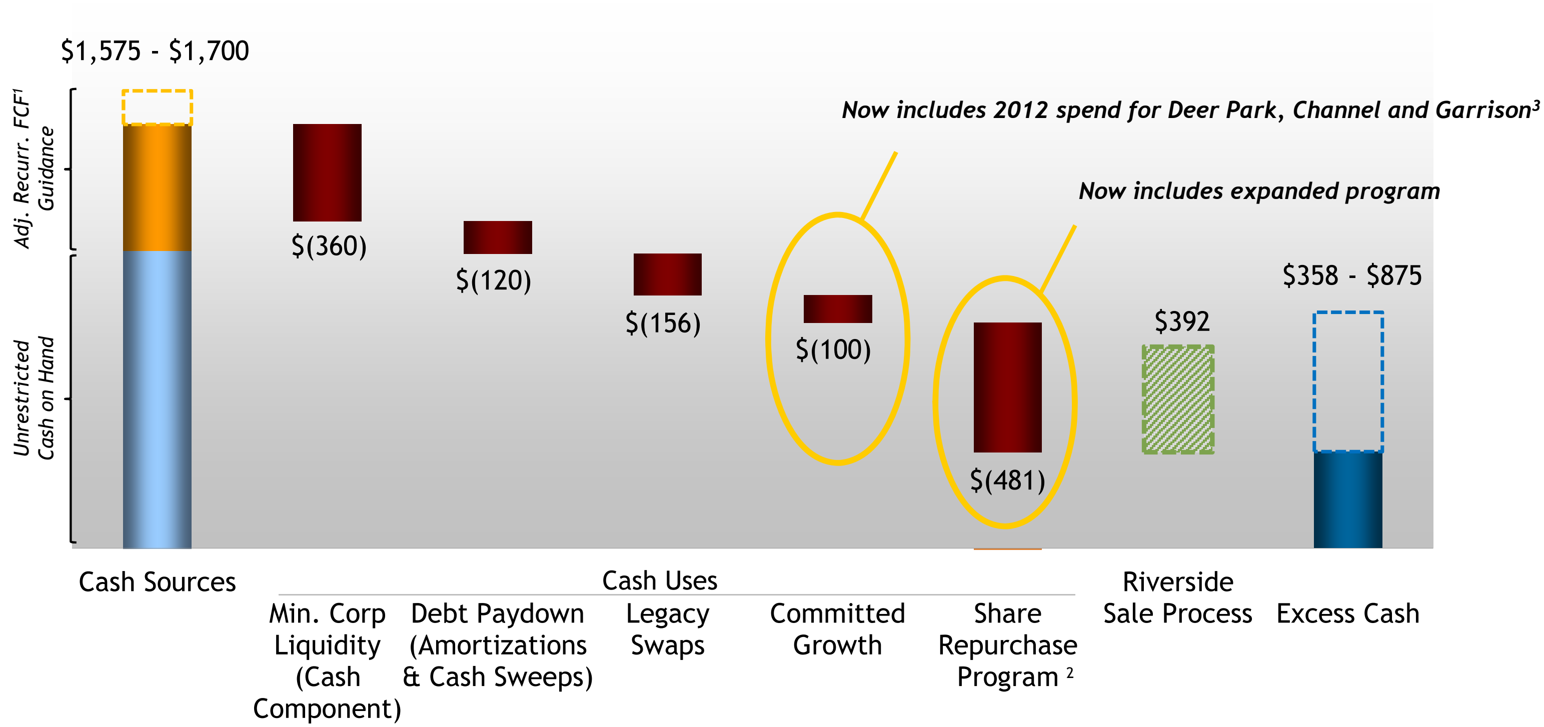
Raising guidance: Low natural gas price environment benefits our flexible, modern fleet

[1] A non-GAAP financial measure. Reconciliations of Adjusted EBITDA and Adjusted Recurring Free Cash Flow to Net Income (Loss), the most comparable U.S. GAAP measure, are included in the appendix.
[2] Updated guidance includes major maintenance expense of $185 million and maintenance capital expenditures of $165 million. Major maintenance expense includes that of unconsolidated investments.
[3] Includes fees for letters of credit.
[4] Interest payments related to legacy LIBOR hedges associated with floating rate First Lien Credit Facility, which has been refinanced.
[5] Assumes exercise of purchase option by customer, for which closing is expected in 4Q12. Amount based upon customer's public disclosures of estimated purchase price.

Capital Allocation Flexibility

($ millions)

Update: 2012 Sources and Uses of Capital



Allocating capital to enhance shareholder value

[1] A non-GAAP financial measure. Reconciliations of Adjusted Recurring Free Cash Flow to Net Income (Loss), the most comparable U.S. GAAP measure, are included in the appendix.
[2] Represents amounts available for repurchase under authorized program during full year 2012. Repurchases have been made during 1Q12, which are not reflected above.
[3] Total projected cost of all projects is <$550 million over 3 years. Amount expressed in nominal 2012 dollars (i.e, "overnight costs") and assumes all-equity financing. Note that projects could potentially be funded with debt at a later date.

APPENDIX

Calpine Value Proposition: Compelling Risk-Adjusted Total Return

CALPINE

The Investment

Modern, clean and reliable natural gas-fired and geothermal power generation fleet, currently trading at a deep discount to replacement cost

Value Drivers

Unlocking Intrinsic Value

- Gas-fired generation will displace a material amount of coal generation
  - Cleaner, more efficient and more economic technology
  - Stable fuel supply at low prices
- Market heat rates (spark spreads) are set to rise
  - Environmental compliance costs
  - Retirements of existing supply: age, economics, compliance
  - Where new capacity needed, power prices must increase to incent investment
- *Calpine: poised to benefit from higher utilization and market heat rates*
  - Highly underutilized in today's market: CCGT capacity factor of 50%[1]

Enhancing Value through Effective Capital Allocation

- As excellent stewards of your capital, we will enhance value by:
  - Pursuing a pipeline of financially disciplined growth
  - Monetizing appropriate assets through sale or contract
  - Returning capital to shareholders over time
- *Our capital structure offers the flexibility necessary to act in our shareholders' best interest*

Experienced management team possesses vision and skill to execute strategy

[1] Calpine's average annual CCGT capacity factor, 2007 – 2010.

Selected Operating Statistics

	1Q 12	1Q 11		1Q 12	1Q 11
Total MWh Generated (in thousands) [1]	***28,865***	***18,973***	*Average Capacity Factor, excl. Peakers*	***54.9%***	***36.9%***
West	8,203	6,195	West	60.3%	46.3%
Texas	9,455	5,671	Texas	59.8%	35.4%
North	5,485	2,824	North	47.1%	24.1%
Southeast	5,722	4,285	Southeast	48.7%	38.1%
Average Availability	***90.3%***	***88.9%***	*Steam Adjusted Heat Rate (Btu/KWh)*	***7,272***	***7,369***
West	93.5%	91.9%	West	7,140	7,386
Texas	85.7%	79.6%	Texas	7,081	7,253
North	89.1%	91.1%	North	7,818	7,746
Southeast	94.1%	94.4%	Southeast	7,271	7,298

[1] Generation has been adjusted to include net interest in generation from our deconsolidated power plants and plants owned by not operated by us.

Plants with no recordable injuries and < 2 % FOF for 1Q12

- ✓ Agnews
- ✓ Auburndale
- ✓ Bethlehem
- ✓ Broad River
- ✓ Carville
- ✓ Columbia
- ✓ Corpus Christi
- ✓ Deer Park
- ✓ Delta
- ✓ Feather River
- ✓ Freestone
- ✓ Geysers*
- ✓ Gilroy
- ✓ Greenleaf I
- ✓ Greenleaf II
- ✓ Hermiston
- ✓ Hog Bayou
- ✓ KIAC
- ✓ King City
- ✓ Los Medanos
- ✓ Metcalf
- ✓ Mid-Atlantic Peakers**
- ✓ Oneta
- ✓ Osprey
- ✓ Otay Mesa
- ✓ Riverside
- ✓ Riverview
- ✓ Rockgen
- ✓ Santa Rosa
- ✓ Solano Peakers
- ✓ Stonybrook
- ✓ Texas City
- ✓ Westbrook
- ✓ York
- ✓ Yuba City
- ✓ Zion

** Geysers includes Bear Canyon, Big Geysers, Cobb Creek, Eagle Rock, Grant, Lakeview, McCabe, Quicksilver, Ridge Line, Socrates, Sonoma, Sulphur Springs, West Ford Flat.*

*** Mid-Atlantic Peakers includes Carlls Corner, Cedar, Christiana, Cumberland, Delaware City, Deepwater, Edge Moor, Middle, Missouri Ave., Sherman Ave., Tasley, West.*

Although Calpine's fleet can be difficult to model, simplifying techniques may help

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NOTE: Our historical approach to modeling tips was intended for application under more static generation volume scenarios. Recent gas price and heat rate trends have introduced variability in generation volume assumptions, making it more difficult for simplified modeling tips to capture the dynamics of our fleet. As such, certain of the recommendations below are intended to reflect a reasonable view on the value of, but not necessarily the volume produced by, our operations. We are currently evaluating the opportunity to further update these modeling tips.

1. Estimate annual generation (MWh) based on market outlook relative to disclosed historical generation with adjustments for asset acquisitions, asset divestitures and plants reaching commercial operations[1].
   - *2012 Note: Due to low gas prices, 2012 generation volume is expected to exceed historical levels. It is reasonable to project full year 2012 generation based upon an annualization of 1Q12 volume.*
   - *2013 – 2014 Note: For this exercise, it is recommended to return to traditional volume levels, adjusted for known additions and divestitures, in years 2013 – 2014[1].*
2. Estimate hedged energy margin based on disclosed % hedged (blue bars) and disclosed hedge margin ($/MWh).
   - Note: 2012 hedged margin ($/MWh) is full year average including YTD settlements. 2012 hedge profile is for balance of year only (applicable for steps 3 and 4 as well).
3. Estimate Geysers unhedged energy margin using MWh estimate (historically, ~6 million MWhs), assume the Geysers unhedged % is the same as the entire portfolio, and apply NP-15 ATC prices.
4. Estimate gas fleet unhedged energy margin based on rough assumptions:
   - In traditional gas price environment, dispatched generation tends to capture 10 – 15% premium to the block on-peak spark spread for open volume.
     - ***The premium to on-peak spark spreads is inversely related to dispatch volumes.***
     - *2012 Note: Assuming use of increased generation volumes, which suggests that plants are operating under more baseload conditions, the premium to on-peak spark spreads should be reduced to 0 or slightly below.*
     - *2013 – 2014 Note: For this exercise, based upon the recommendation to return to traditional volume levels, it is appropriate to reinstate the application of a traditional premium to on-peak spark spreads.*
   - For this exercise, hedge profile is assumed to be relatively flat across all regions, and disclosed regional steam adjusted plant heat rates should be considered when calculating spark spreads.
5. Adjust margin to capture items such as ancillary services and storage positions (benefit of small tens of millions), as well as carbon costs in California.
   - Consider that current NP-15 market heat rates likely include some assumed impact from AB32 no earlier than 1/1/13. To consider Calpine's AB32 costs, apply our combined-cycle average emissions rate of 904 lb/MWh for the California combined-cycle plants and assume that ~65% of those costs are passed on to our customers per contractual arrangements. In addition, factor in the probability that the implementation of AB32 could be delayed.
6. The sum of steps 2 through 5 above will provide you with an estimate of our Energy Margin. To estimate the contribution of Reliability and Other Margin (regulatory capacity and REC revenue) and arrive at an estimate of Total Commodity Margin, simply divide the Energy Margin by the disclosed percentages of Energy Margin as a % of total Commodity Margin.
7. Add estimated margin from unconsolidated investments (Greenfield, Whitby) by multiplying Calpine capacity (net interest) by $110/kw-yr in all periods shown.
   - Since these margins from unconsolidated investments are not included in Commodity Margin, but are included in Adjusted EBITDA, it is necessary to additionally estimate expenses related to unconsolidated investments for purposes of calculating Adjusted EBITDA.
8. When modeling operating costs for the consolidated power plants, use 2011 reported plant operating expense[2] and apply an inflationary factor for 2012 and subsequent periods, with adjustments for asset acquisitions, asset divestitures and plants reaching commercial operations.

Note: Tips are provided to help investors consider simplifying techniques to apply the information disclosed to date in their modeling efforts. These tips are naturally less precise than models based on detailed operational, contract, and hedge position data might be.

[1] Hedge disclosures currently exclude incremental capacity in 2014 related to Deer Park and Channel expansions, pending commencement of construction.

[2] Excluding major maintenance expense, non-cash loss on disposal of assets, and stock-based compensation.

Capital Structure Chart

($ in millions)

Corporate Debt	
Senior Secured Notes	$5,892
First Lien Term Loans	$1,642
Corporate Revolver	—
Total Corporate Debt	$7,534

Project Debt
$1,715

Projects
- Steamboat
  - *Freeport*
  - *Mankato*
- Bethpage
- Otay Mesa
- Pasadena
- Calpine BRSP
- Russell City
- Los Esteros

CCFC
$973

Projects
- Brazos Valley
- Magic Valley
- Sutter
- Hermiston
- Osprey
- Westbrook

Notes Payable & Other
$52

Projects
- Gilroy Cogen
- Other

Capital Lease Obligations
$221

Projects
- Hidalgo
- King City
- Stony Brook
- Other

Total Debt:	$10,495
Add: Net Debt from Unconsolidated Projects[1]	187
Less: Cash, Cash Equivalents & Restr. Cash	(1,241)
Net Debt	$9,441

Net Debt / Adjusted EBITDA[2] = 5.2x

Note: All balances shown as of 3/31/12.

[1] Equal to our net interest in total debt, less cash and cash equivalents and restricted cash from unconsolidated projects.

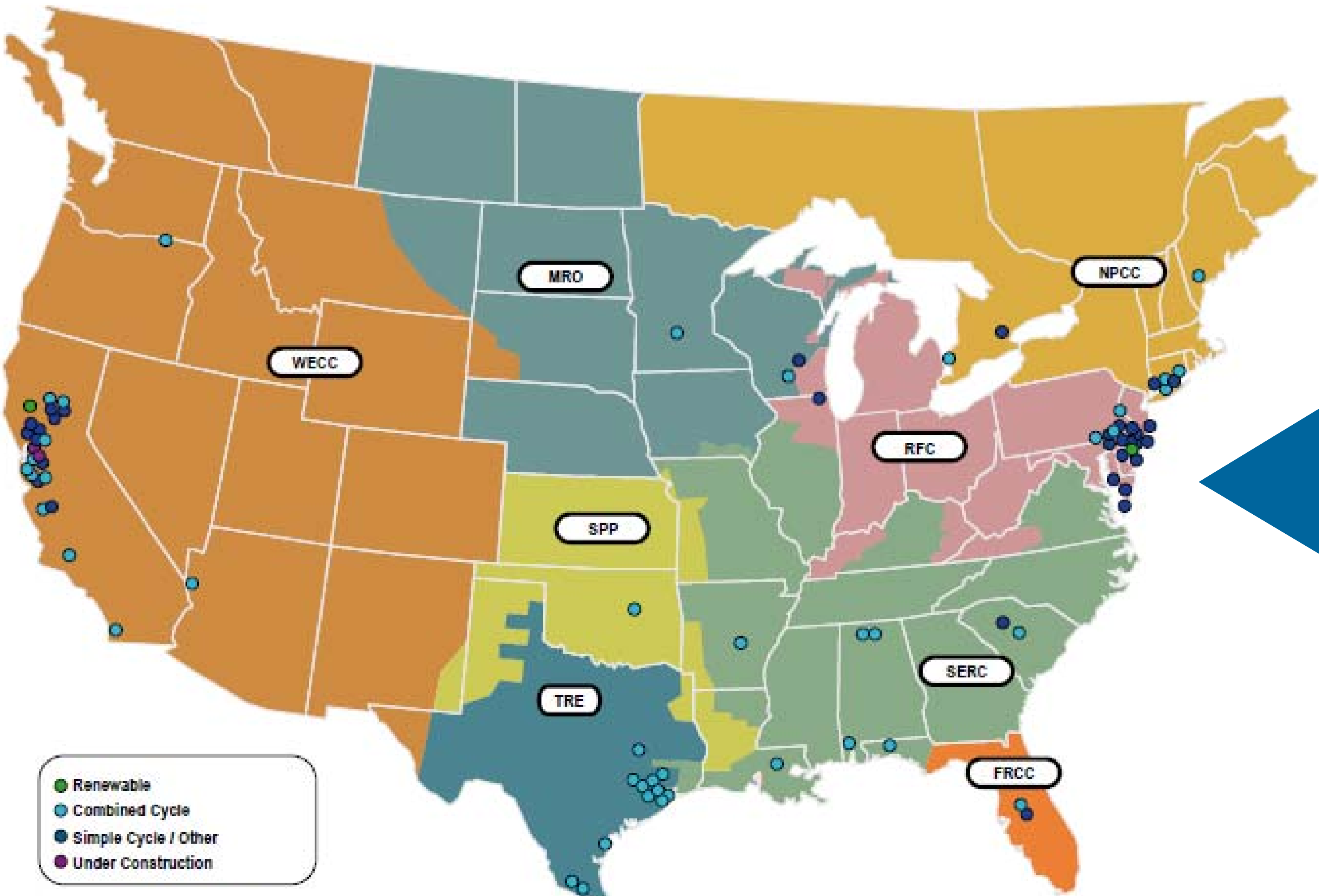
[2] Figures based upon mid-point of 2012 Adj. EBITDA guidance range. Calculation excludes project debt associated with Russell City and Los Esteros while under construction.

Calpine[1] Continues to Benefit from Federal NOL Positions

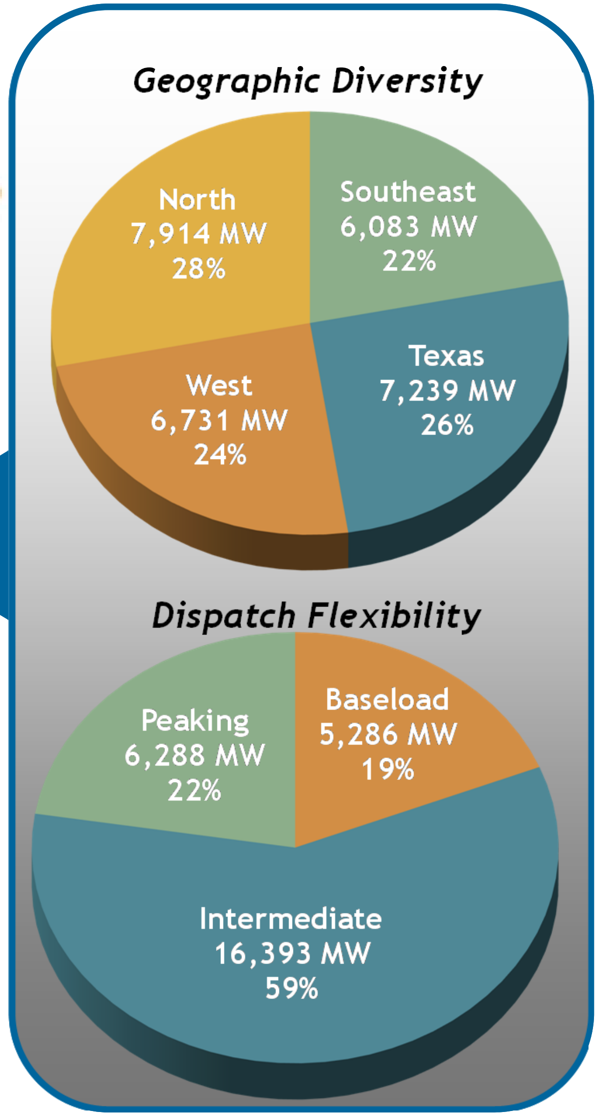
- Federal NOLs at Dec. 31, 2011: $7.9 billion
  - $6.3 billion of NOLs are unrestricted.
  - $1.6 billion continue to have annual limitations.
  - Average annual limitation for the next 3 years is approximately $528 million/year
    - Subject to certain limitations, any amount not utilized in any year can be carried forward and applied in succeeding years

[1] Includes CCFC.

National Portfolio of More Than 28,000 MW



As of April 2012



Calpine Operating Power Plants

As of April 27, 2012

	Technology	Load Type	Location	COD	With Peaking Capacity	CPN Interest	With Peaking Capacity, Net
West Region							
Agnews Power Plant*	Natural Gas	Intermediate	CA	1990	28	100%	28
Creed Energy Center	Natural Gas	Peaking	CA	2003	47	100%	47
Delta Energy Center	Natural Gas	Intermediate	CA	2002	857	100%	857
Feather River Energy Center	Natural Gas	Peaking	CA	2002	47	100%	47
Geysers (15 plants)	Geothermal	Baseload	CA	1971 - 1989	725	100%	725
Gilroy Cogeneration Plant*	Natural Gas	Intermediate	CA	1988	130	100%	130
Gilroy Energy Center	Natural Gas	Peaking	CA	2002	141	100%	141
Goose Haven Energy Center	Natural Gas	Peaking	CA	2003	47	100%	47
Greenleaf 1 Power Plant*	Natural Gas	Intermediate	CA	1989	50	100%	50
Greenleaf 2 Power Plant*	Natural Gas	Intermediate	CA	1989	49	100%	49
Hermiston Power Project	Natural Gas	Intermediate	OR	2002	635	100%	635
King City Cogeneration Plant*	Natural Gas	Intermediate	CA	1989	120	100%	120
King City Peaking Energy Center	Natural Gas	Peaking	CA	2002	44	100%	44
Lambie Energy Center	Natural Gas	Peaking	CA	2003	47	100%	47
Los Medanos Energy Center*	Natural Gas	Intermediate	CA	2001	572	100%	572
Metcalf Energy Center	Natural Gas	Intermediate	CA	2005	605	100%	605
Otay Mesa Energy Center	Natural Gas	Intermediate	CA	2009	608	100%	608
Pastoria Energy Center	Natural Gas	Intermediate	CA	2005	729	100%	729
Riverview Energy Center	Natural Gas	Peaking	CA	2003	47	100%	47
South Point Energy Center	Natural Gas	Intermediate	AZ	2001	530	100%	530
Sutter Energy Center	Natural Gas	Intermediate	CA	2001	578	100%	578
Wolfskill Energy Center	Natural Gas	Peaking	CA	2003	48	100%	48
Yuba City Energy Center	Natural Gas	Peaking	CA	2002	47	100%	47
Total - West Region							**6,731**
Texas Region							
Baytown Energy Center*	Natural Gas	Intermediate	TX	2002	842	100%	842
Brazos Valley Power Plant	Natural Gas	Intermediate	TX	2003	606	100%	606
Channel Energy Center*	Natural Gas	Intermediate	TX	2001	608	100%	608
Clear Lake Power Plant*	Natural Gas	Intermediate	TX	1985	400	100%	400
Corpus Christi Energy Center*	Natural Gas	Intermediate	TX	2002	500	100%	500
Deer Park Energy Center*	Natural Gas	Intermediate	TX	2003	1,001	100%	1,001
Freeport Energy Center*	Natural Gas	Intermediate	TX	2007	236	100%	236
Freestone Energy Center	Natural Gas	Intermediate	TX	2002	994	75%	746
Hidalgo Energy Center	Natural Gas	Intermediate	TX	2000	476	79%	374
Magic Valley Generation Station	Natural Gas	Intermediate	TX	2002	692	100%	692
Pasadena Power Plant*	Natural Gas	Intermediate	TX	1998	781	100%	781
Texas City Power Plant*	Natural Gas	Intermediate	TX	1987	453	100%	453
Total - Texas Region							**7,239**

Calpine Operating Power Plants (cont'd)

As of April 27, 2012

	Technology	Load Type	Location	COD	With Peaking Capacity	CPN Interest	With Peaking Capacity, Net
North Region							
Bayview	Oil	Peaking	VA	1963	12	100%	12
Bethlehem	Natural Gas / Oil	Intermediate	PA	2003	1,130	100%	1,130
Bethpage Energy Center 3	Natural Gas	Intermediate	NY	2005	80	100%	80
Bethpage Peaker	Natural Gas	Peaking	NY	2002	48	100%	48
Bethpage Power Plant	Natural Gas	Intermediate	NY	1989	56	100%	56
Cumberland	Natural Gas / Oil	Peaking	NJ	1990/2009	191	100%	191
Deepwater	Natural Gas / Oil	Peaking	NJ	1954/1958	158	100%	158
Edge Moor*	Natural Gas / Oil	Peaking	DE	1965	725	100%	725
Greenfield Energy Centre	Natural Gas	Intermediate	Ontario, CA	2008	1,038	50%	519
Hay Road	Natural Gas / Oil	Intermediate	DE	1989	1,130	100%	1,130
Kennedy Int'l Airport Power Plant*	Natural Gas	Intermediate	NY	1995	121	100%	121
Mankato Energy Center	Natural Gas	Intermediate	MN	2006	375	100%	375
Mid-Atlantic Peakers**	Natural Gas / Oil	Peaking	NJ/DE/MD/VA	1965-1991	576	100%	576
Riverside Energy Center	Natural Gas	Intermediate	WI	2004	603	100%	603
RockGen Energy Center	Natural Gas	Peaking	WI	2001	503	100%	503
Stony Brook Power Plant*	Natural Gas	Intermediate	NY	1995	47	100%	47
Vineland Solar	Solar	Peaking	NJ	2009	4	100%	4
Westbrook Energy Center	Natural Gas	Intermediate	ME	2001	543	100%	543
Whitby Cogen*	Natural Gas	Intermediate	Ontario, CA	1998	50	50%	25
York Energy Center	Natural Gas	Intermediate	PA	2011	565	100%	565
Zion Energy Center	Natural Gas	Peaking	IL	2002	503	100%	503
Total - North Region							**7,914**
Southeast Region							
Auburndale Peaking Energy Center	Natural Gas	Peaking	FL	2002	117	100%	117
Broad River Energy Center	Natural Gas	Peaking	SC	2000	847	100%	847
Carville Energy Center*	Natural Gas	Intermediate	LA	2003	501	100%	501
Columbia Energy Center*	Natural Gas	Intermediate	SC	2004	606	100%	606
Decatur Energy Center	Natural Gas	Intermediate	AL	2002	795	100%	795
Hog Bayou Energy Center	Natural Gas	Intermediate	AL	2001	237	100%	237
Morgan Energy Center*	Natural Gas	Intermediate	AL	2003	807	100%	807
Oneta Energy Center	Natural Gas	Intermediate	OK	2002	1,134	100%	1,134
Osprey Energy Center	Natural Gas	Intermediate	FL	2004	599	100%	599
Pine Bluff Energy Center*	Natural Gas	Intermediate	AR	2001	215	100%	215
Santa Rosa Energy Center	Natural Gas	Intermediate	FL	2003	225	100%	225
Total - Southeast Region							**6,083**
TOTAL - CALPINE							**27,967**
Projects Under Construction							
Russell City Energy Center	Natural Gas	Intermediate	CA	2013 (est)	619	75%	464
Los Esteros Critical Energy Center	Natural Gas	Intermediate	CA	2013 (est)	309	100%	309

* Indicates cogeneration plant

** Includes: Carll's Corner, Cedar, Christiana, Crisfield, Delaware City, Mickleton, Middle, Missouri Avenue, Sherman Avenue, Tasley, and West

Reg G Reconciliation: Commodity Margin

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Commodity Margin includes our power and steam revenues, sales of purchased power and physical natural gas, capacity revenue, REC revenue, sales of surplus emission allowances, transmission revenue and expenses, fuel and purchased energy expense, fuel transportation expense, RGGI compliance and other environmental costs and cash settlements from our marketing, hedging and optimization activities including natural gas transactions hedging future power sales that are included in mark-to-market activity, but excludes the unrealized portion of our mark-to-market activity and other revenues. Commodity Margin is 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.

Three Months Ended March 31, 2012	West	Texas	North	Southeast	Consolidation And Elimination	Total
Commodity Margin	$ 208	$ 109	$ 144	$ 56	$ —	$ 517
Add: Mark-to-market commodity activity, net and other(1)(2)	36	34	12	10	(8)	84
Less:						
Plant operating expense	81	68	45	33	(6)	221
Depreciation and amortization expense	50	35	33	23	(1)	140
Sales, general and other administrative expense	8	11	6	8	—	33
Other operating expenses(3)	11	2	9	1	(2)	21
(Income) from unconsolidated investments in power plants	—	—	(9)	—	—	(9)
Income from operations	$ 94	$ 27	$ 72	$ 1	$ 1	$ 195

Three Months Ended March 31, 2011	West	Texas	North	Southeast	Consolidation And Elimination	Total
Commodity Margin	$ 233	$ 67	$ 135	$ 54	$ —	$ 489
Add: Mark-to-market commodity activity, net and other(1)	5	(60)	4	(4)	(6)	(61)
Less:						
Plant operating expense	87	80	45	33	(7)	238
Depreciation and amortization expense	46	30	33	23	(1)	131
Sales, general and other administrative expense	11	10	6	5	—	32
Other operating expenses(3)	8	—	7	1	2	18
(Income) from unconsolidated investments in power plants	—	—	(9)	—	—	(9)
Income (loss) from operations	$ 86	$ (113)	$ 57	$ (12)	$ —	$ 18

(1) Mark-to-market commodity activity represents the unrealized portion of our mark-to-market activity, net, included in operating revenues and fuel and purchased energy expense on our Consolidated Condensed Statements of Operations for the three months ended March 31, 2012 and 2011.

(2) Includes $(8) million of lease levelization and $4 million of amortization expense for the three months ended March 31, 2012, related to contracts that became effective in June and August 2011.

(3) Excludes $3 and $2 million of RGGI compliance and other environmental costs for the three months ended March 31, 2012 and 2011, respectively, which are components of Commodity Margin.

Reg G Reconciliation:
Adjusted EBITDA and Adjusted Recurring Free Cash Flow

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Adjusted EBITDA represents net income (loss) before interest, taxes, depreciation and amortization, adjusted for certain non-cash or non-recurring items as detailed in the following reconciliation. Adjusted EBITDA is presented because our management uses Adjusted EBITDA (i) as a measure of operating performance to assist in comparing performance from period to period on a consistent basis and to readily view operating trends; (ii) as a measure for planning and forecasting overall expectations and for evaluating actual results against such expectations; and (iii) in communications with our Board of Directors, shareholders, creditors, analysts and investors concerning our financial performance. 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. 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.

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 presented because our management uses this measure, among others, to make decisions about capital allocation. Adjusted Recurring Free Cash Flow is not intended to represent cash flows from operations 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.

	Three Months Ended March 31,	
	2012	2011
	(in millions)	
Net loss attributable to Calpine	$ (9)	$ (297)
Net income attributable to the noncontrolling interest	—	1
Income tax benefit	(6)	(83)
Debt extinguishment costs and other (income) expense, net	14	100
Loss on interest rate derivatives	14	109
Interest expense, net	182	188
Income from operations	$ 195	$ 18
Add:		
Adjustments to reconcile income from operations to Adjusted EBITDA:		
Depreciation and amortization expense, excluding deferred financing costs[1]	141	132
Major maintenance expense	46	60
Operating lease expense	9	8
Unrealized (gain) loss on commodity derivative mark-to-market activity	(77)	65
Adjustments to reflect Adjusted EBITDA from unconsolidated investments[2][3]	7	8
Stock-based compensation expense	6	5
Loss on dispositions of assets	2	5
Acquired contract amortization	4	—
Other	(8)	2
Total Adjusted EBITDA	$ 325	$ 303
Less:		
Lease payments	9	8
Major maintenance expense and capital expenditures[4]	146	111
Cash interest, net[5]	191	198
Cash taxes	4	4
Other	2	3
Adjusted Recurring Free Cash Flow[6]	$ (27)	$ (21)

(1) Depreciation and amortization expense in the income 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) 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 months ended March 31, 2012 and 2011.

(4) Includes $47 million and $58 million in major maintenance expense for the three months ended March 31, 2012 and 2011, respectively, and $99 million and $53 million in maintenance capital expenditures for the three months ended March 31, 2012 and 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 decrease in working capital of $76 million and $100 million for the three months ended March 31, 2012 and 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.

Reg G Reconciliation: 2012 Adjusted EBITDA and Adjusted Recurring Free Cash Flow Guidance

Full Year 2012 Range:	Low	High
	(in millions)	
GAAP Net Income (Loss)[1]	$ (20)	$ 105
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]	99	99
Adjusted EBITDA	$ 1,675	$ 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	10	10
Adjusted Recurring Free Cash Flow	$ 470	$ 595
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.

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