CALPINE®
NYSE CPN

A GENERATION AHEAD, *today*

Fourth Quarter and Full Year 2011 Investor Update Conference Call

February 10, 2012

Safe Harbor Statement

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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 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

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• 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	

2011 Highlights

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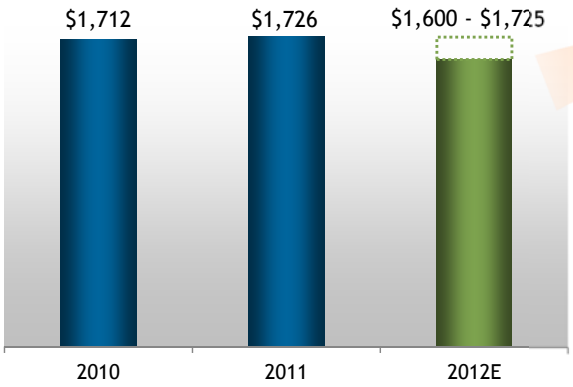
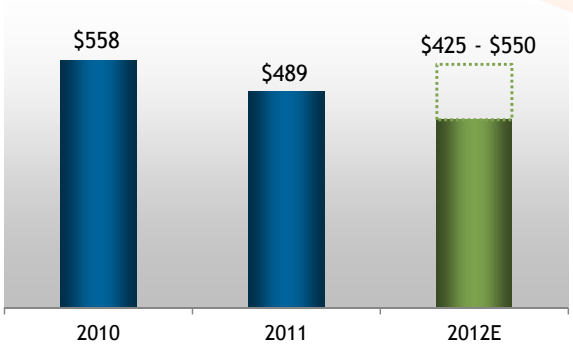
Maintaining Solid Financial Performance

Adjusted EBITDA ($mm)[1]



Adjusted Recurring Free Cash Flow($mm)[1]



Key Messages:

★ Tightening 2012 guidance, including raising lower end
- Unprecedented coal-to-gas switching
- Captured value during 4Q market opportunities

- Delivering solid 2011 performance
  - Met operational & financial targets
  - Produced over 94 billion kWh of electricity in 2011
  - Increased 4Q11 volumes by 19% vs. 4Q10: incremental value
  - Completed 16 major inspections and 15 hot gas path inspections

- Focusing on financially disciplined growth
  - Executed nearly 1,400 MW of long-term power contracts
  - Completed 10 turbine upgrades
  - Constructing nearly 600 MW[2] of CCGT capacity
  - Actively permitting nearly 1,200 MW of CCGT capacity

Committed to enhancing shareholder value

[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] Represents Calpine's net interest.

Secular Forces Affecting U.S. Power Generation Sector: Then vs. Now

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Shifting Fuel Cost Fundamentals

2008:
- Natural gas: Limited domestic supply linked to world oil price; LNG imports
- Coal: Affordable, domestic commodity

2012:
- Natural gas: 100+ years supply of affordable, domestic commodity; LNG exports
- Coal: More expensive international commodity

Stricter Environmental Regulation

2008:
- Climate change driving call for carbon regulation
- Lower priority: CSAPR, MATS

2012:
- Top priority: Health concerns driving CSAPR, MATS rules
- Climate change skeptics prevail… for now

Aging Power Generation Infrastructure

2008:
- Few fossil capacity additions; new renewables subsidized by power prices and government

2012:
- Still limited new capacity: existing fleet continues to age; investments in improvements / maintenance less economic
- Scarcity on the margin in some markets

Government Fiscal Responsibility

2008:
- "Zero carbon" at any cost
- Strong government backing of nuclear and renewables

2012:
- Reality: Solyndra, Fukushima, budget and debt concerns

Calpine: Well-positioned for secular trends

Lower Gas Prices Present Opportunities

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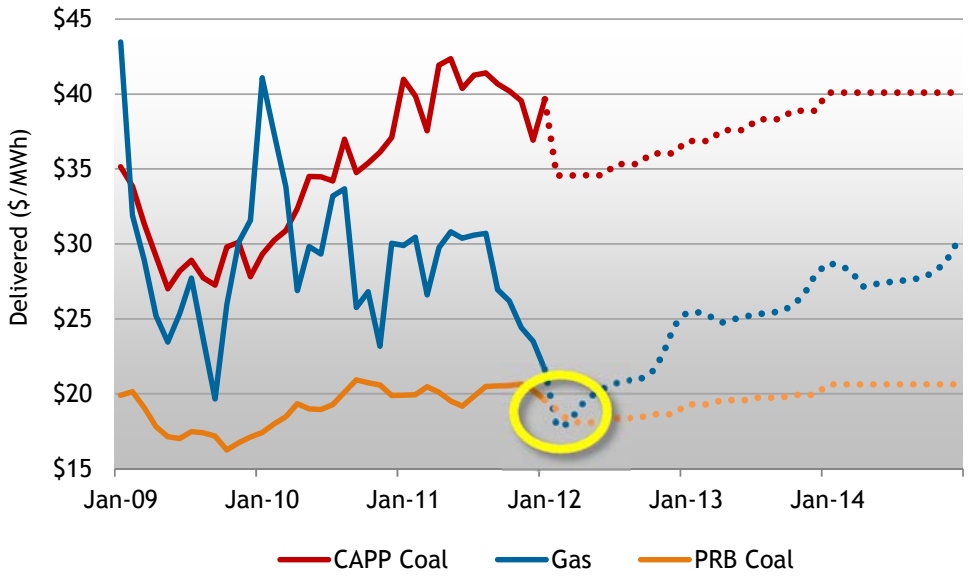
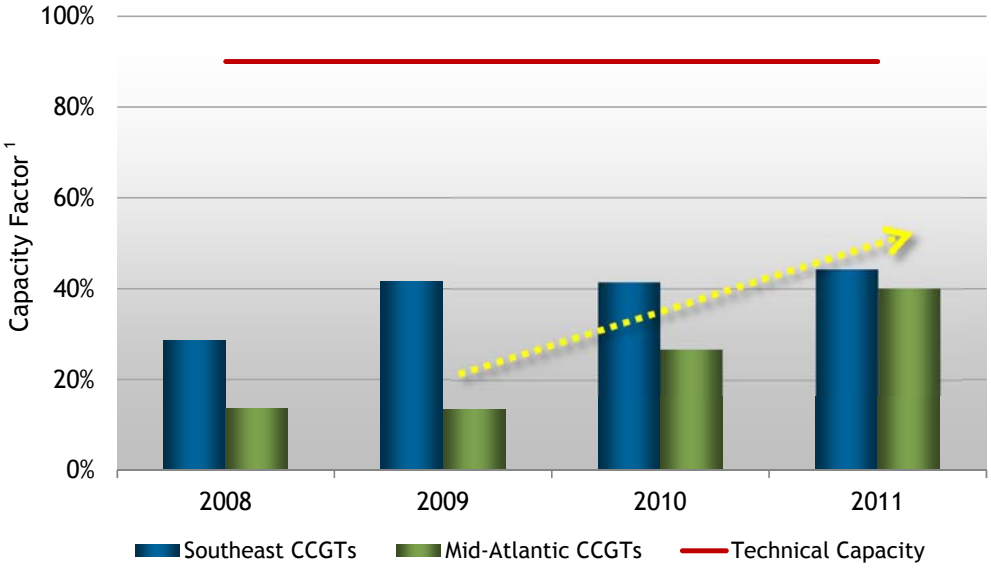
As Gas Prices Decline and Coal Generation is Displaced…



Source: NYMEX, Calpine data (1/24/12). 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 cost.

…Existing Gas-Fired Generation is the Economic Solution

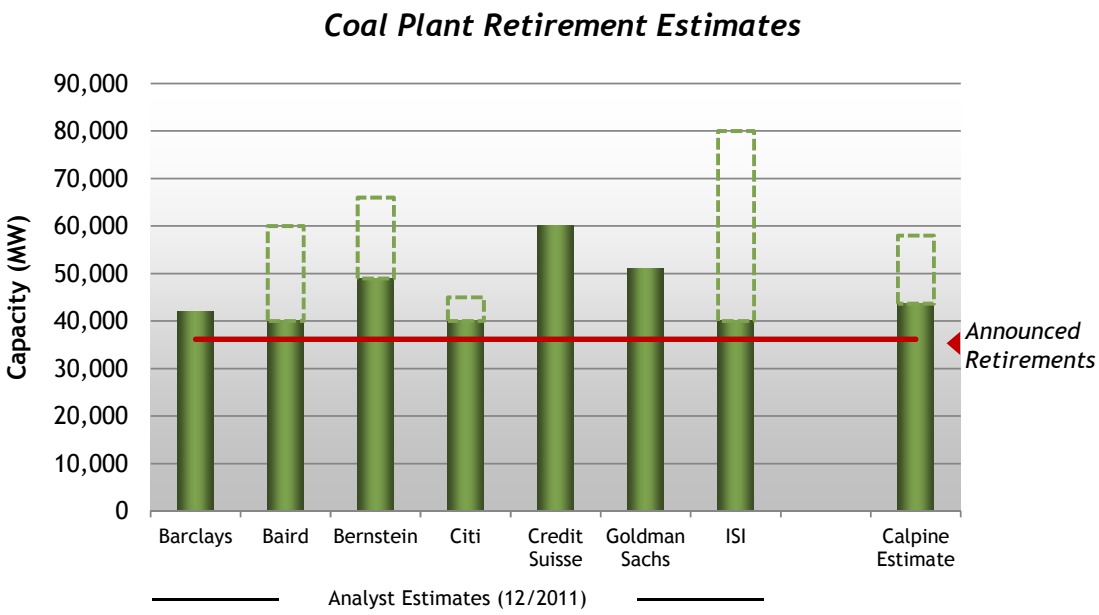


[1] Capacity factors in all periods reflect currently owned combined-cycle plants in respective markets.

Low natural gas prices drive volume expansion for existing, efficient gas-fired generation

Coal Retirements: Reinforcing the Need for Efficient, Clean Generation

Significant Capacity Expected to Retire: Age, Economics, Regulation



Source: Analyst reports, Calpine, MJ Bradley.

Only a Small Fraction of Replacement Currently Under Construction

Region	Fossil Generation Currently Under Construction
ERCOT	1,000 MW
PJM	2,600 MW

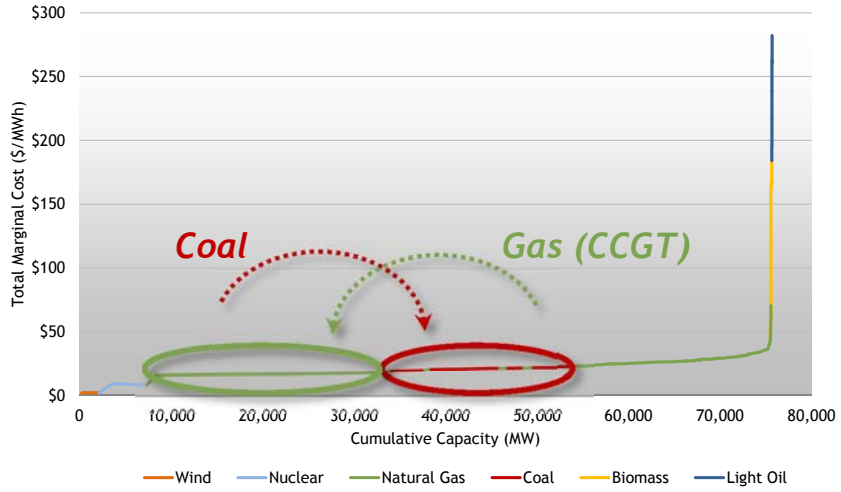
Source: Ventyx EV, ERCOT CDR 2011 Winter Update, California Energy Commission, Calpine.

Poised to benefit from announced retirements and implementation of public policy

OPERATIONS REVIEW

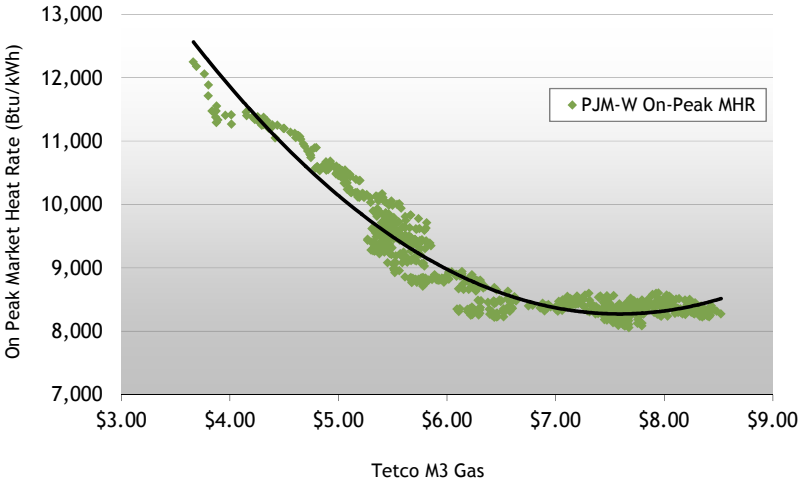
Calpine: Resilience in Low Gas-Price Environment

ERCOT Supply Stack
Feb 2012



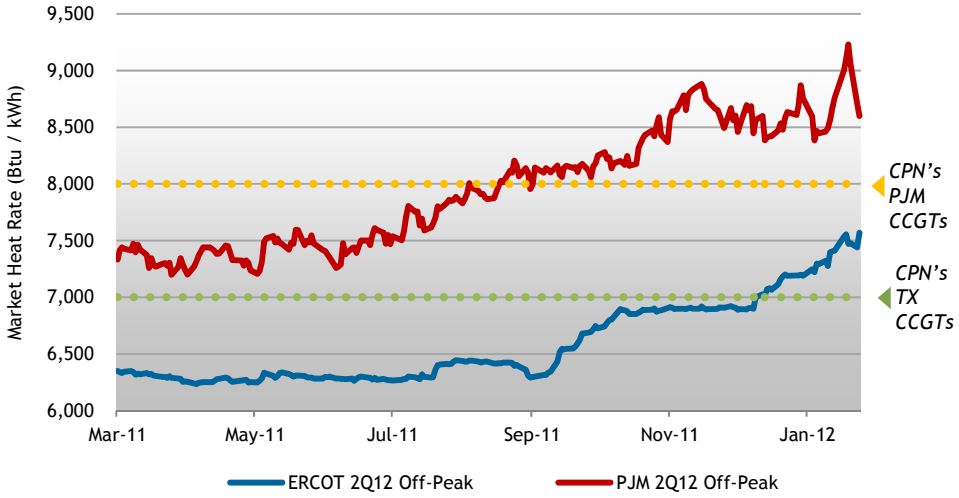
Source: Ventyx EV, Company data. Commodity price assumptions (per mmBtu) include: coal ($2.00), natural gas ($2.32), uranium ($0.56), light oil ($21.41), biomass ($15.70).

Relationship between PJM West Gas Prices and Market Heat Rates



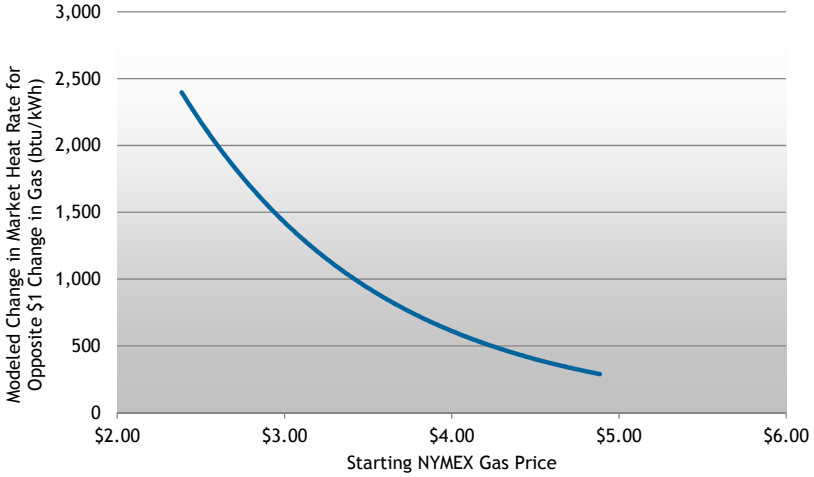
Note: Reflects annual average forward prices for 2012 delivery, for trade dates from 01/02/2009 through 12/31/2011. Source: Broker data, Calpine.

Off-Peak Market Heat Rates Rising



Source: Broker data, Calpine. As of 01/24/12.

Portfolio Gas/Heat Rate Relationship at a Given Gas Price



Note: Reflects Calpine analysis of production-weighted average market heat rates for ERCOT-Houston, NP-15, PJM-East and Southern, holding all other factors constant (eg, coal prices, load, supply). Does not account for hedges.

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

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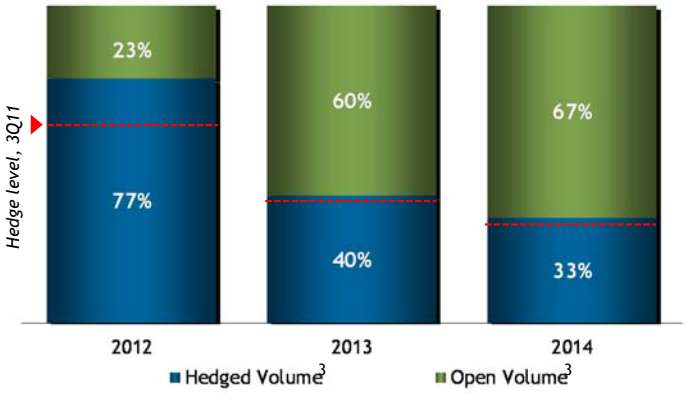
Energy Hedge Profile[2]

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

80% 75% 75%

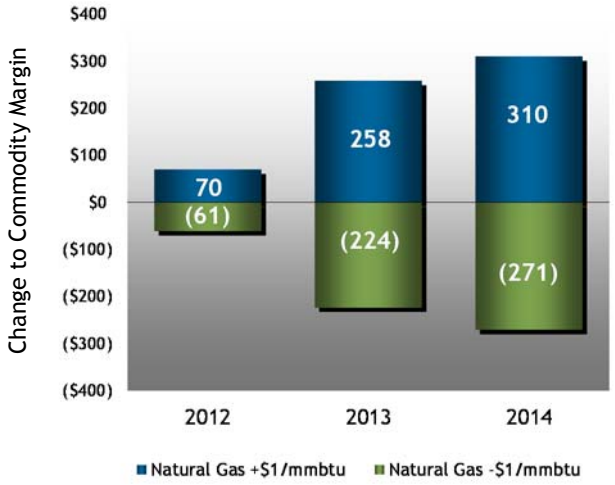
Use in conjunction with modeling tips in appendix



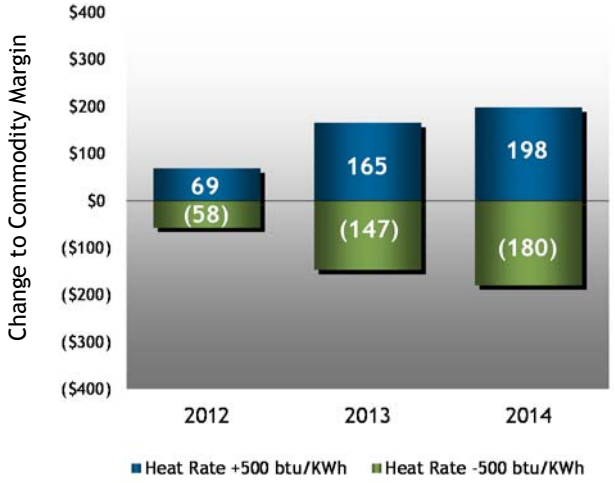
	2012	2013	2014
Hedged Margin ($/MWh)[2]	$21	$28	$26
Avg. MW in Operation [2,4]	27,981	28,152	28,201

Sensitivities

Natural Gas Price Sensitivity[2]



Market Heat Rate Sensitivity[2]



Summary

- Added hedges in 2012, though still modestly open summer in PJM/TX
- Effective gas position
  - 2012: Modestly short
  - 2013: Closer to neutral
  - 2014: Some length
- Data shown treats market heat rate and gas price as independent variables; however
  - Market heat rates show inverse relationships with gas prices in some markets; and
  - The magnitude of the inverse relationship shifts with gas price
  - *See prior slide for illustration*

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

[2] Estimated as of 02/03/12 (sensitivities) and 01/27/12 (all else). 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.

[4] Represents Calpine's forecasted average annual capacity of net ownership interest with peaking capacity. Capacity additions or deletions are reflected in the anticipated month of completion.

Focused on Best-in-Class Operations

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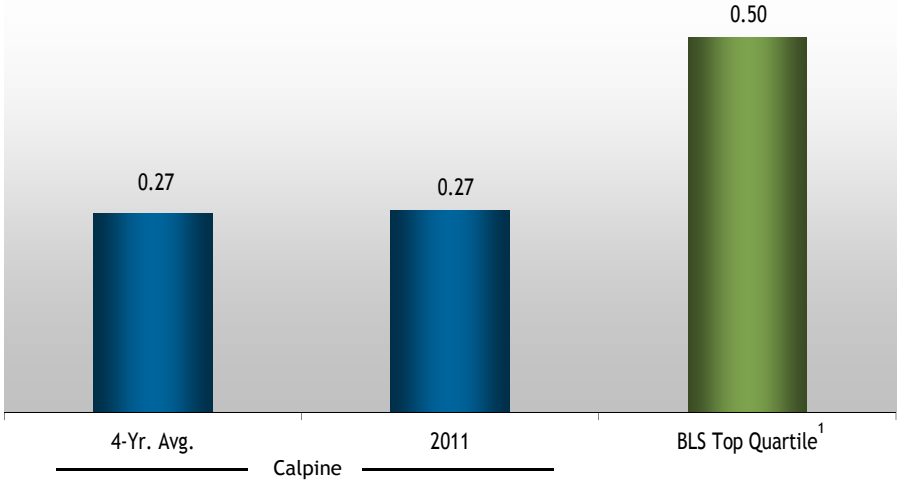
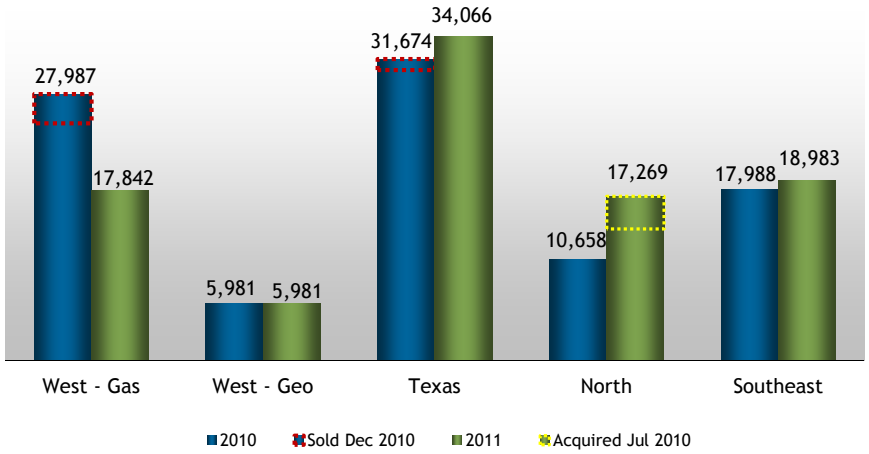
Employee Lost-Time Incident Rate

Maintaining focus on safety



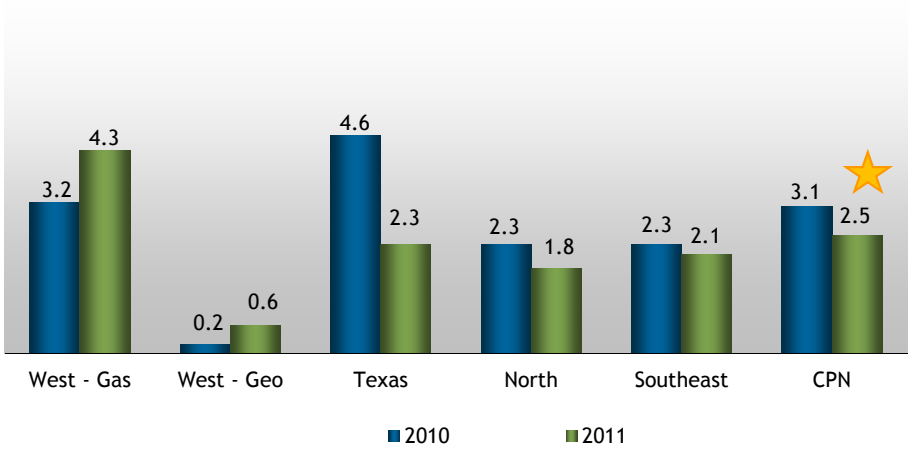
Generation in Key Markets (000 MWh)[2]

Generated 94 million MWh: Plant sales (↓), Hydro in CA (↓), Extreme summer in TX (↑), Full year of Mid-Atlantic (↑)



Forced Outage Factor (FOF, %)

Achieved goal of 2.5% fleetwide FOF



Plants with no recordable injuries and < 2 % FOF for 2011

- ✓ Baytown
- ✓ Broad River
- ✓ Carville
- ✓ Columbia
- ✓ Decatur
- ✓ Deepwater
- ✓ Deer Park
- ✓ Delta
- ✓ Edge Moor
- ✓ Geysers*
- ✓ Gilroy
- ✓ Grant
- ✓ Greenleaf 1
- ✓ Greenleaf 2
- ✓ Hay Road
- ✓ Hermiston
- ✓ Hidalgo
- ✓ KIAC
- ✓ King City
- ✓ Los Esteros
- ✓ Magic Valley
- ✓ Mankato
- ✓ Metcalf
- ✓ Morgan
- ✓ Oneta
- ✓ Osprey
- ✓ Otay Mesa
- ✓ Pasadena
- ✓ Pine Bluff
- ✓ Riverside
- ✓ Rockgen
- ✓ Sana Rosa
- ✓ Solano Peakers
- ✓ Sutter
- ✓ Westbrook
- ✓ York
- ✓ Zion

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

[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 deconsolidated projects, plants owned but not operated, and plants/interests sold or retired during 2010.

ERCOT: Outlook Remains Bullish

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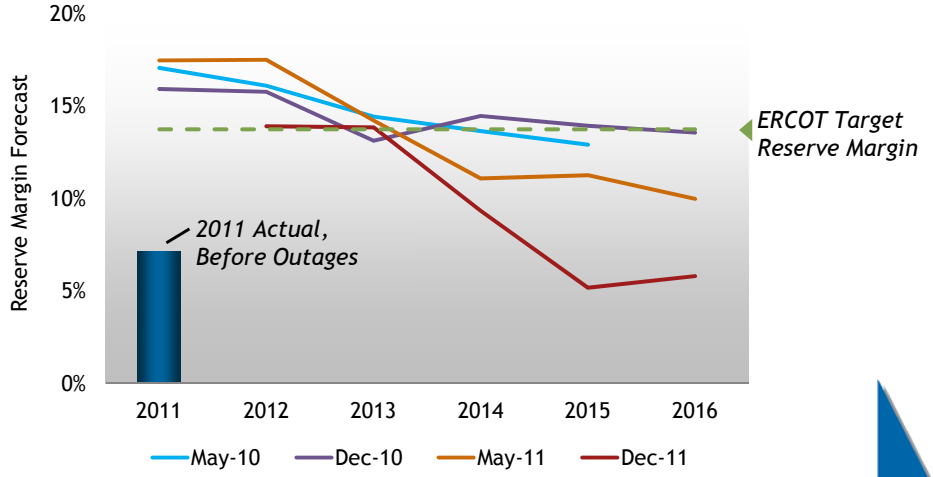
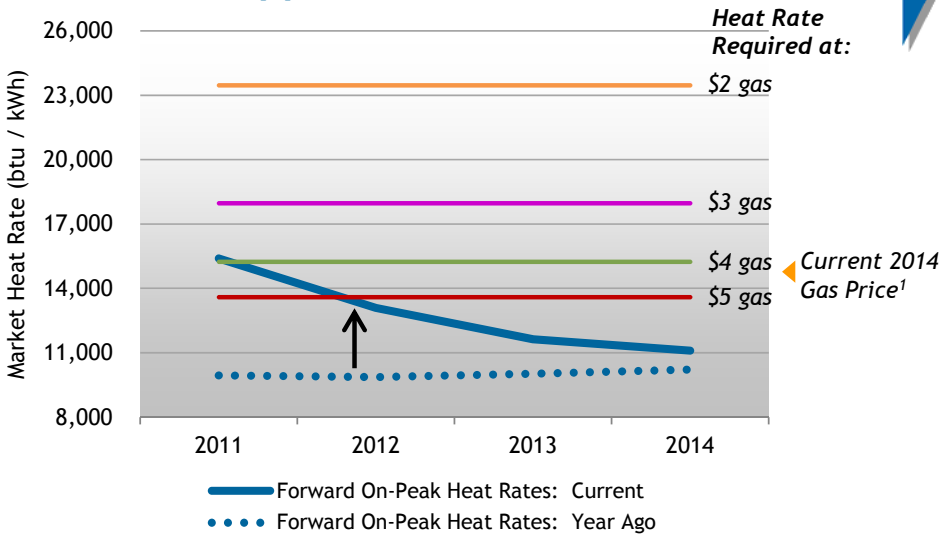
ERCOT needs new capacity…



Source: ERCOT CDR, Calpine. Dec 2011 CDR has been modified to reflect the addition of 1,166 MW of capacity whose announced retirement in 2012 has been withdrawn. 2011 actual reserve margin based upon peak load of 68,294 MW achieved on 8/3/11.

…but recent heat rate environment doesn't support new build investment



Source: Broker data, Calpine. Assumes $135/kW-Yr levelized cost of new CCGT, operating 4,100 on-peak hours per year. Prices of natural gas shown on per-mmBtu basis. Data as of 01/24/12 (current) and 01/31/11 (year ago).
[1]Houston Ship Channel.

ERCOT addressing through market reforms to better demonstrate scarcity

Rule Changes

Effective Jan 2012:

- Established price floor for Non-Spin Reserves: $120/MWh online, $180/MWh offline
- Set Responsive Reserve energy price (when used for SCED[2] energy) at system-wide offer cap ($3000/MWh)
- Set Up Regulation energy price at system-wide offer cap (when used for SCED energy)

Under Discussion:

- Institutionalize process to recall mothballed units for capacity and set related energy price at the system wide offer cap
- Transition 500 MW of ancillary services from Non-Spin Reserves to Responsive Reserves
- Set energy price for capacity committed through Reliability Unit Commitment at system-wide offer cap
- Steepen and increase limit of power balance penalty curve

Market fundamentals continuing to trend favorably

[2] Security Constrained Economic Dispatch.

Regional Dynamics: California and PJM

California:
Quest for fair compensation for flexible generation

Near Term

- ↑ AB32: Carbon cap-and-trade program in 2013
- ↑ Drier weather, so far…?

Longer Term

- ↓ Renewables penetration: Addition of intermittent resources
- ↑ CPUC/Cal-ISO increasingly concerned around longer-term reliability
  - Sutter treatment a key indicator

PJM:
Robust market fundamentals persist

- ↑ EPA MATS rule: Mid-decade coal retirements
- ↑ New Jersey HEDD rule: Commitment to 2015 enforcement
- ↔ First glance: 2015/2016 capacity auction parameters
  - \+ Rejection of CONE revisions; higher CONE
  - \+ Higher MOPR
  - – Lower demand
  - – Higher MAAC CETL
- ↔ State interventions (NJ, MD): Legal challenges significant

FINANCIAL REVIEW

Financial Overview

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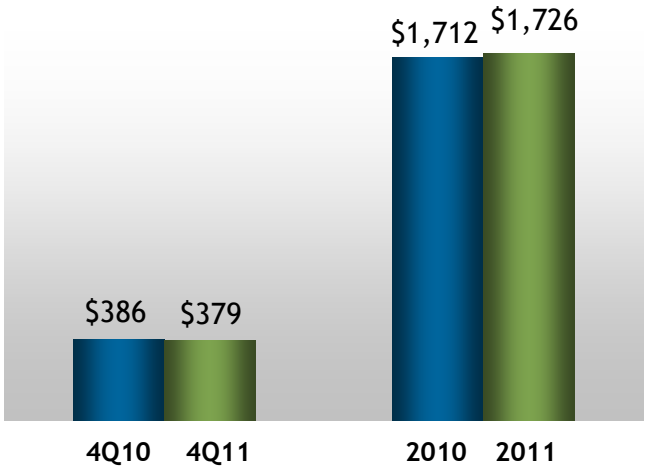
Key Messages:

- Narrowing 2012 guidance: Adj. EBITDA $1,600 - $1,725M
  - Coal-to-gas switching
  - Incremental hedging during 4Q11
- Met 2011 guidance
  - Strong operational performance
  - Effective hedging
  - Addition of York Energy Center and full year of Mid-Atlantic

($ millions)

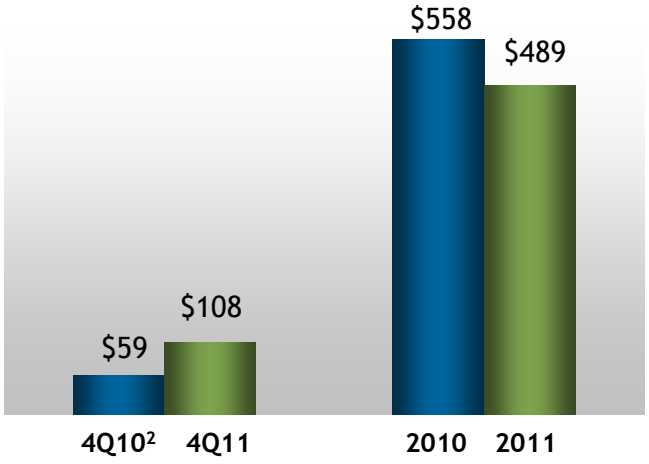
Adjusted EBITDA[1]



2011 Accomplishments:

- ☑ Completed $6.9B corporate refinancing program early
  - Increased strategic flexibility
  - Limited near-term debt maturities
  - Launched repurchase program: $124M (>40%) complete
- ☑ Enhanced liquidity and simplified capital structure
  - Unwound complex leasing arrangements
  - Upsized and extended CDHI
  - Agreed to buy out 2 equity partners in Calif. Peaker subsidiary[3]
- ☑ Secured attractive financing for significant growth projects
- ☑ Improved credit metrics
  - Achieved credit rating upgrade from S&P

Adjusted Recurring FCF[1]



[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] 4Q10 Adjusted Recurring Free Cash Flow has been recast to conform with current year presentation, which excludes settlements of non-hedging interest rate swaps.
[3] Subject to FERC approval and terms of the agreements.

Regional Adjusted EBITDA: 4Q 2011 vs. 2010

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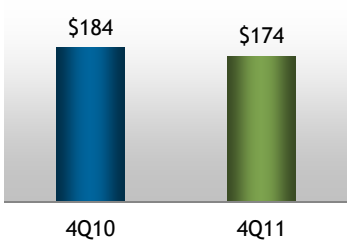
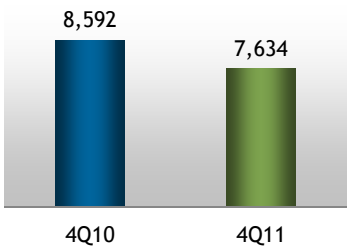
($ millions, 000 MWh)

West Region

Adjusted EBITDA[1]



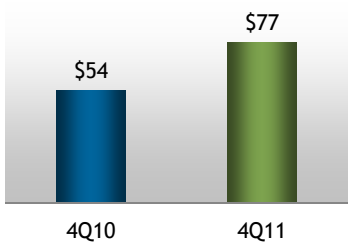
Generation



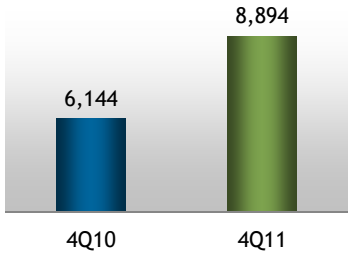
- Sale of Colorado plants (-$14M)
- Lower Commodity Margin[1]
  - – Lower generation: weaker market conditions
  - + Origination activities
- Lower plant operating expenses[2]

Texas Region

Adjusted EBITDA[1]



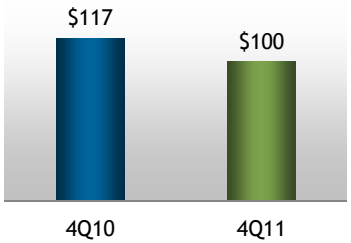
Generation



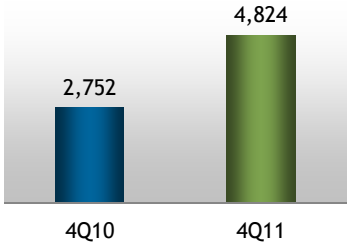
- Higher Commodity Margin[1]
  - + Contribution from hedges
  - + Higher generation: off-peak volume increase
  - – Lower steam margin
- Lower plant operating expenses[2]

North Region

Adjusted EBITDA[1]



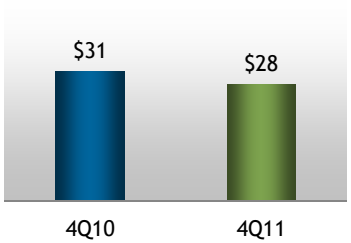
Generation



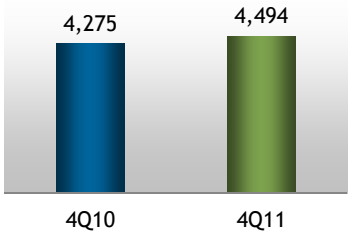
- Lower Commodity Margin[1]
  - – Lower RPM capacity payments (-$22M)
  - + Addition of York Energy Center
  - + Higher generation, modest impact: Fewer outages in 4Q11
  - – No high-margin weather events in 4Q11

Southeast Region

Adjusted EBITDA[1]



Generation



- Lower Commodity Margin[1]
  - – Expiration of hedge contracts
  - – Lower spark spreads: mild weather

[1] A non-GAAP financial measure. Reconciliations of Commodity Margin to Income from Operations and of Adjusted EBITDA to Net Income (Loss), the most comparable U.S. GAAP measure, are included in the appendix.

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

Regional Adjusted EBITDA: 2011 vs. 2010

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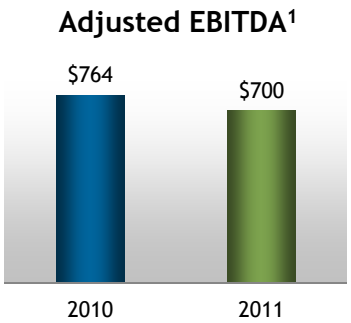
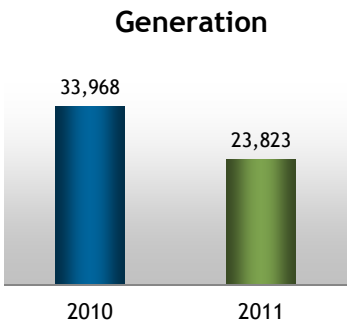
($ millions, 000 MWh)

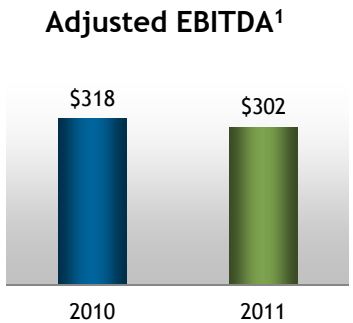
West Region

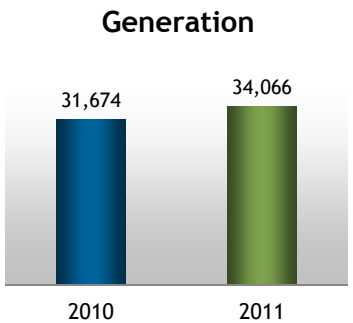




- Sale of Colorado plants (-$75M)
- Lower Commodity Margin[1]
  - — Lower generation: extreme hydro conditions in CA
  - + Origination activities
- Lower plant operating and SG&A expenses[2]

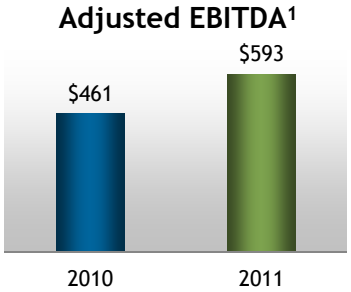
Texas Region

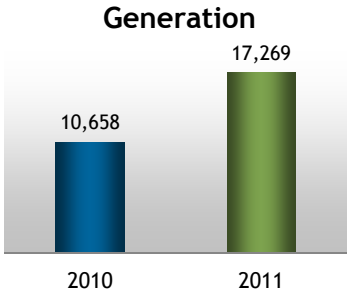




- Lower Commodity Margin[1]
  - — Unplanned outages during extreme Feb weather event
  - — Sale of 25% of Freestone (Dec 2010)
  - + Contribution from hedges
- Lower plant operating expenses[2]

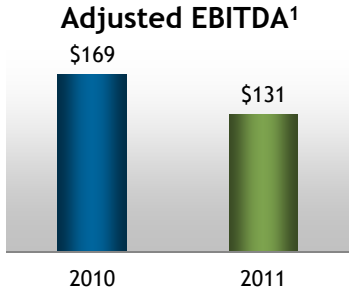
North Region

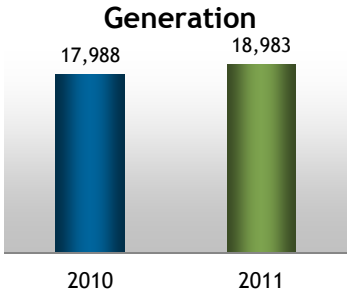




- Higher Commodity Margin[1]
  - + Full year of Mid-Atlantic fleet (acquired Jul 2010)
  - + Addition of York Energy Center
  - — Lower RPM capacity prices (2H11 vs 2H10)

Southeast Region





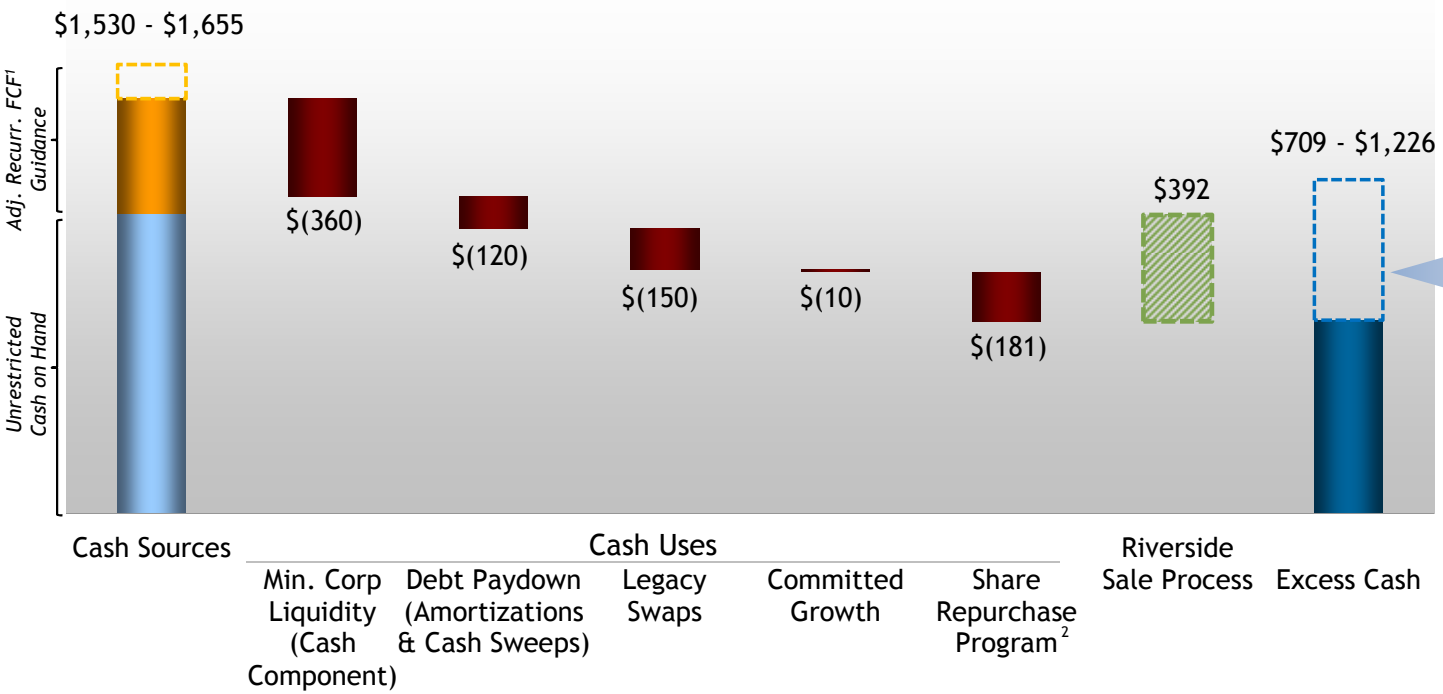
- Lower Commodity Margin[1]
  - — Expiration of hedge contracts
  - — Unscheduled outages (2Q11, 3Q11)

[1] A non-GAAP financial measure. Reconciliations of Commodity Margin to Income from Operations and of Adjusted EBITDA to Net Income (Loss), the most comparable U.S. GAAP measure, are included in the appendix.
[2] Excluding major maintenance expense, non-cash loss on disposal of assets, stock-based compensation, and acquisition-related costs.

2012 Capital Allocation Outlook

CALPINE NYSE CPN

($ millions)



Excess cash continues to build this year and into the future

Disciplined approach to capital allocation

[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] Represents amounts available for repurchase under authorized program as of 12/31/11. Additional repurchases have been made subsequent to this date.

Calpine 2012 Goals & Initiatives

Premier operating company

- Maintain top quartile safety performance
- Be diligent on cost controls and forecasting
- Leverage best practices across operations and maintenance programs

Enhance shareholder value

- Invest capital prudently
- Continue to reposition asset base
- Seek opportunities to de-risk and simplify capital structure

Leader in environmental responsibility

- Lead the wholesale power sector by our actions
- Work collaboratively with key legislators, regulators and stakeholders to shape policy
- Monetize our fleet's environmental advantages

Leverage scale of existing portfolio of plants

- Offer products from diverse national portfolio to meet customer needs
- Leverage scale of business for additional savings opportunities
- Pursue imbedded opportunities for high-return growth within existing fleet

Customer-oriented origination business

- Continue focus on customer outreach and innovative solutions for customer needs
- Deliver on our commitments
- Anticipate customer needs and develop innovative products and services

APPENDIX

Calpine Value Proposition: Compelling Risk-Adjusted Total Return

CALPINE NYSE CPN

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

CALPINE NYSE CPN

	4Q11	4Q10		4Q11	4Q10
Total MWh Generated (in thousands) [1]	***25,846***	***21,763***	*Average Capacity Factor, excl. Peakers*	***48.7%***	***40.7%***
West	***7,634***	***8,592***	West	55.3%	59.1%
Texas	***8,894***	***6,144***	Texas	55.2%	36.6%
North	***4,824***	***2,752***	North	40.3%	25.1%
Southeast	***4,494***	***4,275***	Southeast	39.2%	36.8%
Average Availability	***91.4%***	***87.5%***	*Steam Adjusted Heat Rate (Btu/KWh)*	***7,358***	***7,374***
West	95.8%	91.1%	West	7,287	7,319
Texas	89.4%	83.1%	Texas	7,203	7,292
North	89.4%	86.7%	North	7,867	7,947
Southeast	91.5%	89.9%	Southeast	7,279	7,264

	YTD 11	YTD 10		YTD 11	YTD 10
Total MWh Generated (in thousands) [1]	***94,141***	***94,288***	*Average Capacity Factor, excl. Peakers*	***44.3%***	***46.0%***
West	23,823	33,968	West	43.6%	56.5%
Texas	34,066	31,674	Texas	53.2%	48.1%
North	17,269	10,658	North	35.9%	32.8%
Southeast	18,983	17,988	Southeast	40.6%	38.0%
Average Availability	***90.1%***	***90.4%***	*Steam Adjusted Heat Rate (Btu/KWh)*	***7,412***	***7,338***
West	88.2%	91.5%	West	7,418	7,316
Texas	89.0%	87.6%	Texas	7,243	7,236
North	91.6%	90.7%	North	7,919	7,819
Southeast	91.9%	92.5%	Southeast	7,312	7,315

[1] Generation has been adjusted to include net interest in generation from deconsolidated projects and from plants and interest sold or retired during 2010 in all periods.

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

CALPINE NYSE CPN

Ideas to help investors assess trends based on disclosures to date:

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. *Due to low gas prices, 2012 generation volumes could exceed historical levels. These incremental volumes should be modeled using market spark spreads at a discount to the on-peak spark spreads suggested in step 4*.
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 NP-15 ATC prices.
4. Estimate gas fleet unhedged gross margin based on rough assumptions:
   - Dispatched generation tends to capture 10 – 15% premium to peak spark spread on open volume.
   - For this exercise, hedge profile is 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 ~50% 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[1] as a baseline for 2012, then apply an inflationary factor to 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] *Excluding major maintenance expense, non-cash loss on disposal of assets, and stock-based compensation.*

Capital Structure Chart

CALPINE NYSE CPN

($ in millions)

Corporate Debt	
Senior Secured Notes	$5,892
First Lien Term Loans	$1,646
Corporate Revolver	—
Total Corporate Debt	**$7,538**

Project Debt — $1,636

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

CCFC — $972

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

Notes Payable & Other — $55

Projects
- Gilroy Cogen
- Other

Capital Lease Obligations — $224

Projects
- Hidalgo
- King City
- Stony Brook
- Other

Total Debt:	$10,425
Add: Net Debt from Unconsolidated Projects[1]	193
Less: Cash, Cash Equivalents & Restr. Cash	(1,446)
Net Debt	**$9,172**

Net Debt / Adjusted EBITDA[2] = 5.1x

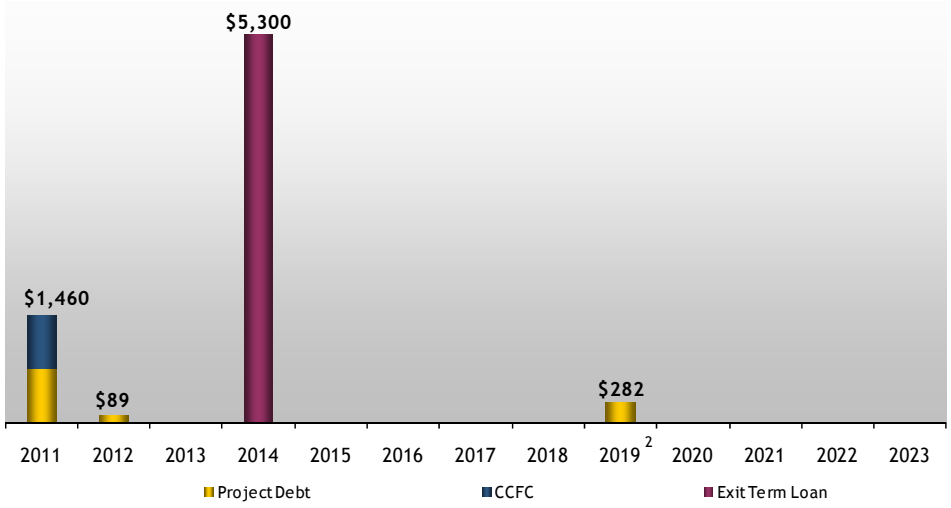
Note: All balances shown as of 12/31/11.
[1] Equal to our net interest in total debt, less cash and cash equivalents and restricted cash from unconsolidated projects.
[2] Figures based upon actual 2011 Adj. EBITDA. Calculation excludes project debt associated with Russell City and Los Esteros while under construction.

De-Risking & Maturity Management

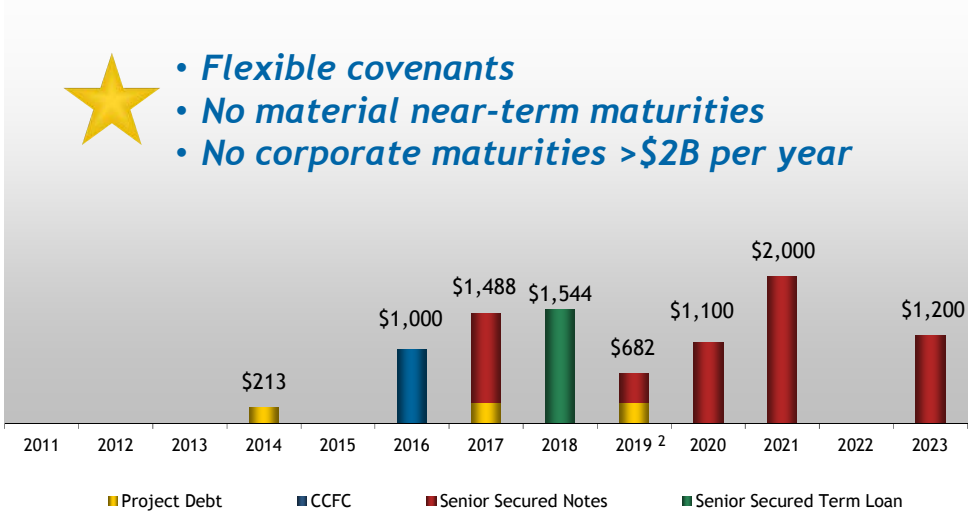
CALPINE NYSE CPN

($ millions)

March 2009[1]



December 2011



Managing maturities while improving flexibility

Note: 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.

[1] 2009 chart as depicted in March 2009, excluding 2009 and 2010 balances.

[2] Project debt in 2019 represents projected balance for OMEC. Put price in the PPA approximates the projected debt balance.

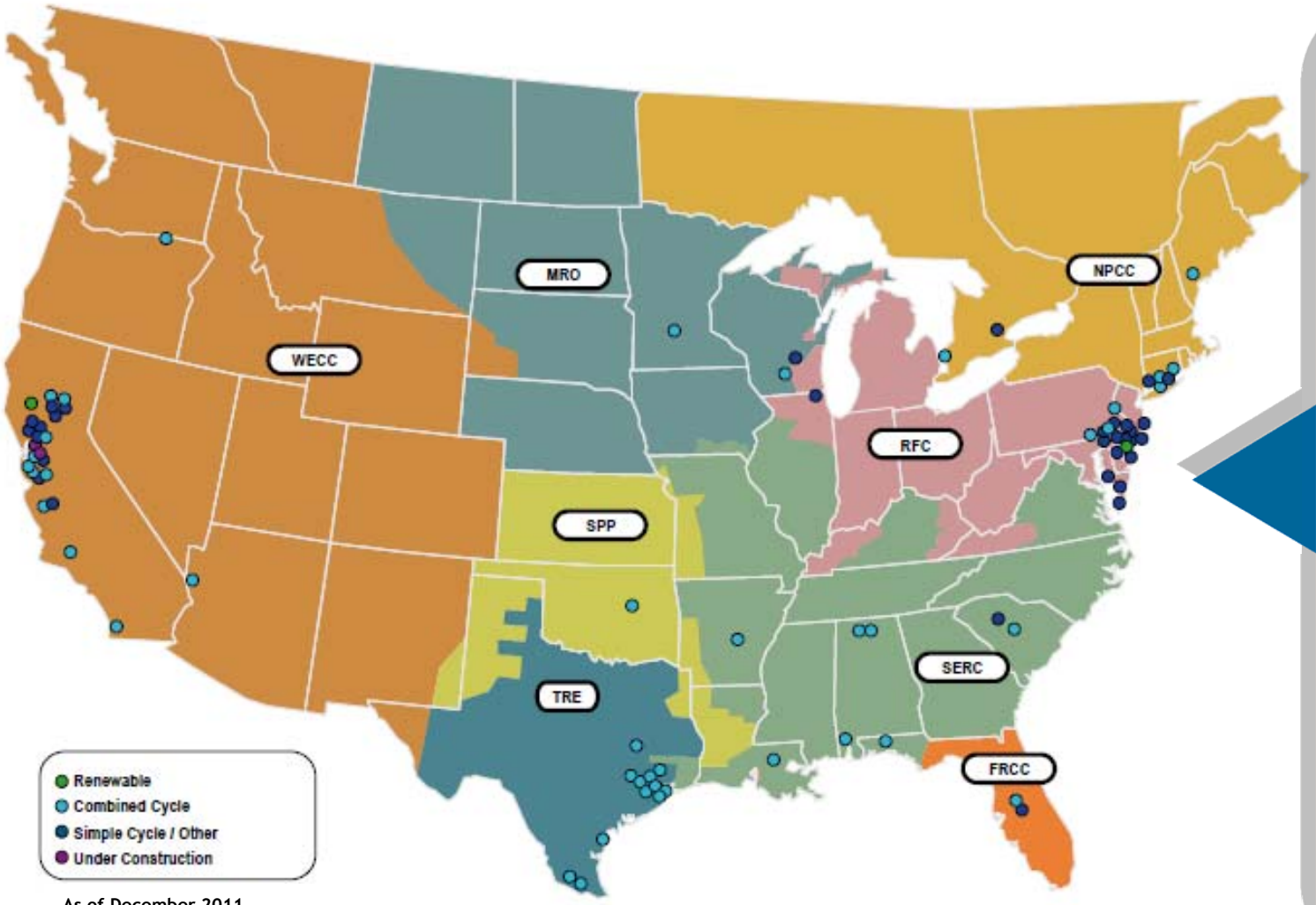
[3] Includes unconsolidated entities.

Calpine[1] Continues to Benefit from Federal NOL Positions

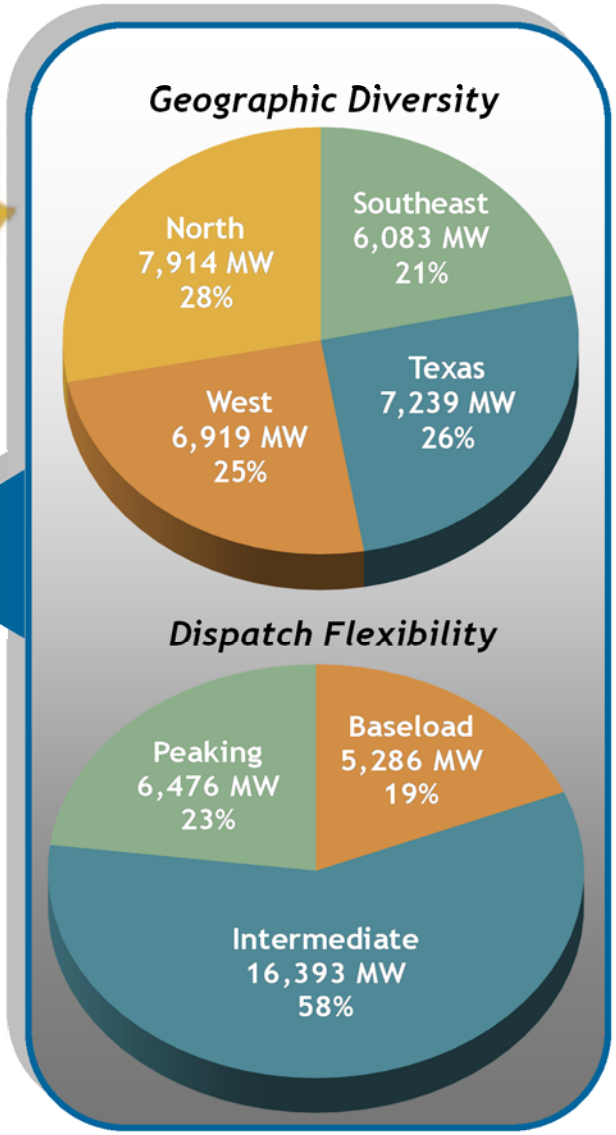
- Federal NOLs at Dec. 31, 2011: $7.9 billion
  - $2.4 billion are not subject to annual 382 limitations.
  - $6.3 billion of NOLs are unrestricted.
  - Average annual limitation for the next 3 years is approximately $528 million/year
    - Subject to certain limitations, any amount not utilized in any year can be carried forward and applied in succeeding years

[1] Includes CCFC.

National Portfolio of More Than 28,000 MW



As of December 2011



Calpine Operating Power Plants

As of February 10, 2012

CALPINE NYSE CPN

	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 Esteros Critical Energy Facility	Natural Gas	Peaking	CA	2003	188	100%	188
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							**6,919**
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 February 10, 2012

CALPINE NYSE CPN

	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	1973	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	1964-1991	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							**28,155**
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)	120	100%	120

* 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

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 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 December 31, 2011					
	West	Texas	North	Southeast	Consolidation And Elimination	Total
Commodity Margin	$ 263	$ 112	$ 126	$ 52	$ —	$ 553
Add: Mark-to-market commodity activity, net and other[1][2]	77	(48)	(1)	5	(9)	24
Less:						
Plant operating expense	83	42	41	34	(7)	193
Depreciation and amortization expense	52	36	36	23	(2)	145
Sales, general and other administrative expense	14	10	5	4	(1)	32
Other operating expenses[3]	11	1	7	2	(1)	20
(Income) from unconsolidated investments in power plants	—	—	(9)	—	—	(9)
Income (loss) from operations	$ 180	$ (25)	$ 45	$ (6)	$ 2	$ 196

	Three Months Ended December 31, 2010					
	West	Texas	North	Southeast	Consolidation And Elimination	Total
Commodity Margin	$ 271	$ 104	$ 145	$ 56	$ —	$ 576
Add: Mark-to-market commodity activity, net and other[1]	9	(59)	3	(9)	(10)	(66)
Less:						
Plant operating expense	87	68	55	36	(8)	238
Depreciation and amortization expense	52	37	35	25	(2)	147
Sales, general and other administrative expense	19	9	8	1	1	38
Other operating expenses[3]	16	—	7	2	(3)	22
Impairment losses	97	—	—	—	—	97
(Gain) on sale of assets, net	—	(119)	—	—	—	(119)
(Income) from unconsolidated investments in power plants	—	—	(2)	—	—	(2)
Income (loss) from operations	$ 9	$ 50	$ 45	$ (17)	$ 2	$ 89

Reg G Reconciliation: Commodity Margin (cont'd)

CALPINE NYSE CPN

	Year Ended December 31, 2011					
	West	Texas	North	Southeast	Consolidation And Elimination	Total
Commodity Margin	$ 1,061	$ 469	$ 704	$ 240	$ —	$ 2,474
Add: Mark-to-market commodity activity, net and other [1][2]	113	(102)	(13)	1	(32)	(33)
Less:						
Plant operating expense	380	235	177	141	(29)	904
Depreciation and amortization expense	192	135	138	90	(5)	550
Sales, general and other administrative expense	43	43	24	22	(1)	131
Other operating expenses[3]	41	3	30	5	(2)	77
(Income) from unconsolidated investments in power plants	—	—	(21)	—	—	(21)
Income (loss) from operations	$ 518	$ (49)	$ 343	$ (17)	$ 5	$ 800

	Year Ended December 31, 2010					
	West	Texas	North	Southeast	Consolidation And Elimination	Total
Commodity Margin	$ 1,080	$ 504	$ 535	$ 272	$ —	$ 2,391
Add: Mark-to-market commodity activity, net and other [1]	69	89	21	22	(30)	171
Less:						
Plant operating expense	351	285	138	123	(29)	868
Depreciation and amortization expense	207	150	111	109	(7)	570
Sales, general and other administrative expense	55	38	45	12	1	151
Other operating expenses[3]	59	2	28	4	(2)	91
Impairment losses	97	—	—	19	—	116
(Gain) on sale of assets, net	—	(119)	—	—	—	(119)
(Income) from unconsolidated investments in power plants	—	—	(16)	—	—	(16)
Income from operations	$ 380	$ 237	$ 250	$ 27	$ 7	$ 901

(1) Mark-to-market commodity activity represents the unrealized portion of our mark-to-market activity, net, included in operating revenues and fuel and purchased energy expense on our Consolidated Statements of Operations for the three months and years ended December 31, 2011 and 2010.

(2) Includes $(3) million and $12 million of lease levelization and $3 million and $8 million of contract amortization for the three months and year ended December 31, 2011, respectively, related to contracts that became effective in 2011.

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

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

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 December 31,		Year Ended December 31,	
	2011	2010	2011	2010
	(in millions)			
Net income (loss) attributable to Calpine	$ (13)	$ (24)	$ (190)	$ 31
Net income attributable to the noncontrolling interest	—	—	1	—
Discontinued operations, net of tax expense	—	(162)	—	(193)
Income tax expense (benefit)	23	(106)	(22)	(68)
Other (income) expense and debt extinguishment costs, net	7	70	115	106
(Gain) loss on interest rate derivatives, net	(4)	136	145	223
Interest expense, net	183	175	751	802
Income from operations	$ 196	$ 89	$ 800	$ 901
Add:				
Adjustments to reconcile income from operations to Adjusted EBITDA:				
Depreciation and amortization expense, excluding deferred financing costs[1]	146	149	552	573
Impairment losses	—	97	—	116
Major maintenance expense	36	46	205	157
Operating lease expense	9	12	35	45
Unrealized (gain) loss on commodity derivative mark-to-market activity	(23)	69	25	(143)
Gain on sale of assets	—	(119)	—	(119)
Adjustments to reflect Adjusted EBITDA from unconsolidated investments[2][3]	6	9	36	34
Stock-based compensation expense	6	6	24	24
(Gain) loss on dispositions of assets	(1)	3	16	10
Conectiv acquisition-related costs[4]	—	11	—	36
Contract amortization	3	—	8	—
Other	1	—	25	3
Adjusted EBITDA from continuing operations	379	372	1,726	1,637
Adjusted EBITDA from discontinued operations	—	14	—	75
Total Adjusted EBITDA	$ 379	$ 386	$ 1,726	$ 1,712
Less:				
Lease payments	9	12	35	45
Major maintenance expense and capital expenditures[5]	62	114	397	317
Cash interest, net[6]	194	186	781	768
Cash taxes	2	7	13	17
Other	4	8	11	7
Adjusted Recurring Free Cash Flow[7]	$ 108	$ 59	$ 489	$ 558

(1) Depreciation and amortization expense in the income from operations calculation on our Consolidated Statements of Operations excludes amortization of other assets.
(2) Included in our Consolidated Statements of Operations in (income) from unconsolidated investments in power plants.
(3) Adjustments to reflect Adjusted EBITDA from unconsolidated investments include unrealized (gain) loss on mark-to-market activity of nil for the three months ended December 31, 2011 and 2010, and $1 million for the years ended December 31, 2011 and 2010.
(4) Includes $2 million and $26 million included in sales, general and other administrative expenses and $9 million and $10 million included in plant operating expense for the three and twelve months ended December 31, 2010, respectively.
(5) Includes $27 million and $201 million in major maintenance expense for the three months and year ended December 30, 2011, respectively, and $35 million and $196 million in maintenance capital expenditures for the three months and year ended December 30, 2011, respectively. Includes $49 million and $159 million in major maintenance expense for the three months and year ended December 31, 2010, respectively, and $65 million and $158 million in maintenance capital expenditures for the three months and year ended December 31, 2010, respectively.
(6) Includes commitment, letter of credit and other bank fees from both consolidated and unconsolidated investments, net of capitalized interest and interest income.
(7) Excludes decrease in working capital of $8 million and increase in working capital of $13 million for the three months and year ended December 31, 2011, respectively, and a decrease in working capital of $76 million and $44 million for the three and twelve months ended December 31, 2010, 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. 2010 Adjusted Recurring Free Cash Flow has been recast to conform with current year presentation, which excludes settlements of non-hedging interest rate swaps.

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]	$ (50)	$ 75
Plus:		
Interest expense, net of interest income	765	765
Depreciation and amortization expense	575	575
Major maintenance expense	185	185
Operating lease expense	35	35
Other[2]	90	90
Adjusted EBITDA	$ 1,600	$ 1,725
Less:		
Operating lease payments	35	35
Major maintenance expense and maintenance capital expenditures[3]	350	350
Recurring cash interest, net[4]	770	770
Cash taxes	10	10
Other	10	10
Adjusted Recurring Free Cash Flow	$ 425	$ 550
Non-recurring interest rate swap payments[5]	150	150

(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) Includes fees for letters of credit, net of interest income.
(5) Interest payments related to legacy LIBOR hedges associated with floating rate First Lien Credit Facility, which has been refinanced.

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