

Energy Future Holdings



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**EFH Corp.  
Q2 2010 Investor Call**

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**August 3, 2010**

# Safe Harbor Statement

***This presentation contains forward-looking statements, which are subject to various risks and uncertainties. Discussion of risks and uncertainties that could cause actual results to differ materially from management's current projections, forecasts, estimates and expectations is contained in EFH Corp.'s filings with the Securities and Exchange Commission (SEC).***

## **Regulation G**

***This presentation includes certain non-GAAP financial measures. A reconciliation of these measures to the most directly comparable GAAP measures is included in the appendix to this presentation. In addition to the risks and uncertainties set forth in EFH Corp.'s SEC filings, the forward-looking statements in this presentation regarding the company's long-term hedging program could be affected by, among other things: any change in the ERCOT electricity market, including a regulatory or legislative change, that results in wholesale electricity prices not being largely correlated to natural gas prices; any decrease in market heat rates as the long-term hedging program generally does not mitigate exposure to changes in market heat rates; the unwillingness or failure of any hedge counterparty or the lender under the commodity collateral posting facility to perform its obligations; or any other unforeseen event that results in the inability to continue to use a first lien to secure a substantial portion of the hedges under the long-term hedging program.***

# Today's Agenda

**Financial and Operational  
Overview**

**Paul Keglevic  
Executive Vice President & CFO**

**Q2 2010 Review**

**Q&A**

# EFH Corp. Adjusted (Non-GAAP) Operating Results - QTR

Consolidated: reconciliation of GAAP net income (loss) to adjusted (non-GAAP) operating results<sup>1</sup>  
 Q2<sup>2</sup> 09 vs. Q2 10; \$ millions, after tax

Factor	Q2 09	Q2 10	Change
GAAP net (loss) attributable to EFH Corp.	(155)	(426)	(271)
Items excluded from adjusted (non-GAAP) operating results (after tax) - noncash:			
Unrealized commodity-related mark-to-market net (gains) losses	206	93	(113)
Unrealized mark-to-market net (gains) losses on interest rate swaps	(299)	165	464
Debt extinguishment (gain) – Q2 10 debt exchanges and repurchases	-	(83)	(83)
<b>EFH Corp. adjusted (non-GAAP) operating (loss)</b>	<b>(248)</b>	<b>(251)</b>	<b>(3)</b>

<sup>1</sup> See Appendix for Regulation G reconciliations and definitions.

<sup>2</sup> Three months ended June 30

# EFH Corp. Adjusted (Non-GAAP) Operating Results - YTD

Consolidated: reconciliation of GAAP net income (loss) to adjusted (non-GAAP) operating results<sup>1</sup>  
YTD<sup>2</sup> 09 vs. YTD 10; \$ millions, after tax

Factor	YTD 09	YTD 10	Change
GAAP net income (loss) attributable to EFH Corp.	287	(71)	(358)
Items excluded from adjusted (non-GAAP) operating results (after tax) - noncash:			
Unrealized commodity-related mark-to-market net (gains) losses	(457)	(546)	(89)
Unrealized mark-to-market net (gains) losses on interest rate swaps	(432)	235	667
Goodwill impairment charge	90	-	(90)
Income tax charge recorded as a result of health care legislation enacted by Congress in March 2010	-	8	8
Debt extinguishment (gain) – 2010 debt exchanges and repurchases	-	(93)	(93)
<b>EFH Corp. adjusted (non-GAAP) operating (loss)</b>	<b>(512)</b>	<b>(467)</b>	<b>45</b>

<sup>1</sup> See Appendix for Regulation G reconciliations and definitions.

<sup>2</sup> Six months ended June 30

# EFH Corp. Adjusted (Non-GAAP) Operating Results - QTR

Consolidated key drivers of the change in (non-GAAP) operating results  
Q2<sup>1</sup> 10 vs. Q2 09; \$ millions, after tax

Description/Drivers	Better (Worse) Than Q2 09
<b>Competitive business<sup>2</sup>:</b>	
Impact of new lignite-fueled generation units	70
Lower amortization of intangibles arising from purchase accounting	17
Higher margin from asset management and the retail business	14
Higher fuel expense at the legacy coal-fueled generation units primarily due to increased transportation costs	(25)
Lower production from nuclear fueled generation units due to timing of refueling outage	(19)
All other - net	(12)
Contribution margin	45
Gains on sales of assets (reported in other income)	48
Lower costs related to outsourcing transition and new retail customer care system	19
Higher net interest expense driven by lower capitalized interest due to completion of new generation units	(42)
Higher depreciation reflecting the three new lignite-fueled generation units and mining facilities	(29)
Higher operating costs related to new generation units	(16)
Higher nuclear plant maintenance due to timing of refueling outage	(11)
Higher depreciation reflecting ongoing investment in generation fleet	(9)
All other - net	(1)
Total improvement - Competitive business	4
<b>Regulated business:</b>	
Higher distribution tariffs, including the rates approved in the September 2009 final rate review order	16
Surcharge to recover AMS deployment costs	10
Higher depreciation reflecting higher depreciation rates approved in the September final rate review order and infrastructure investment	(21)
Higher costs reflecting amortization of regulatory assets approved for recovery, AMS implementation and higher transmission fees	(14)
All other – net (includes noncontrolling interests)	2
Total improvement – Regulated business (80% owned by EFH Corp.)	(7)
<b>Total change in EFH Corp. adjusted (non-GAAP) operating results</b>	<b>(3)</b>

<sup>1</sup> Three months ended June 30

<sup>2</sup> Competitive business consists of Competitive Electric segment and Corp. & Other.

# EFH Corp. Adjusted (Non-GAAP) Operating Results - YTD

Consolidated key drivers of the change in (non-GAAP) operating results  
YTD<sup>1</sup> 10 vs. YTD 09; \$ millions, after tax

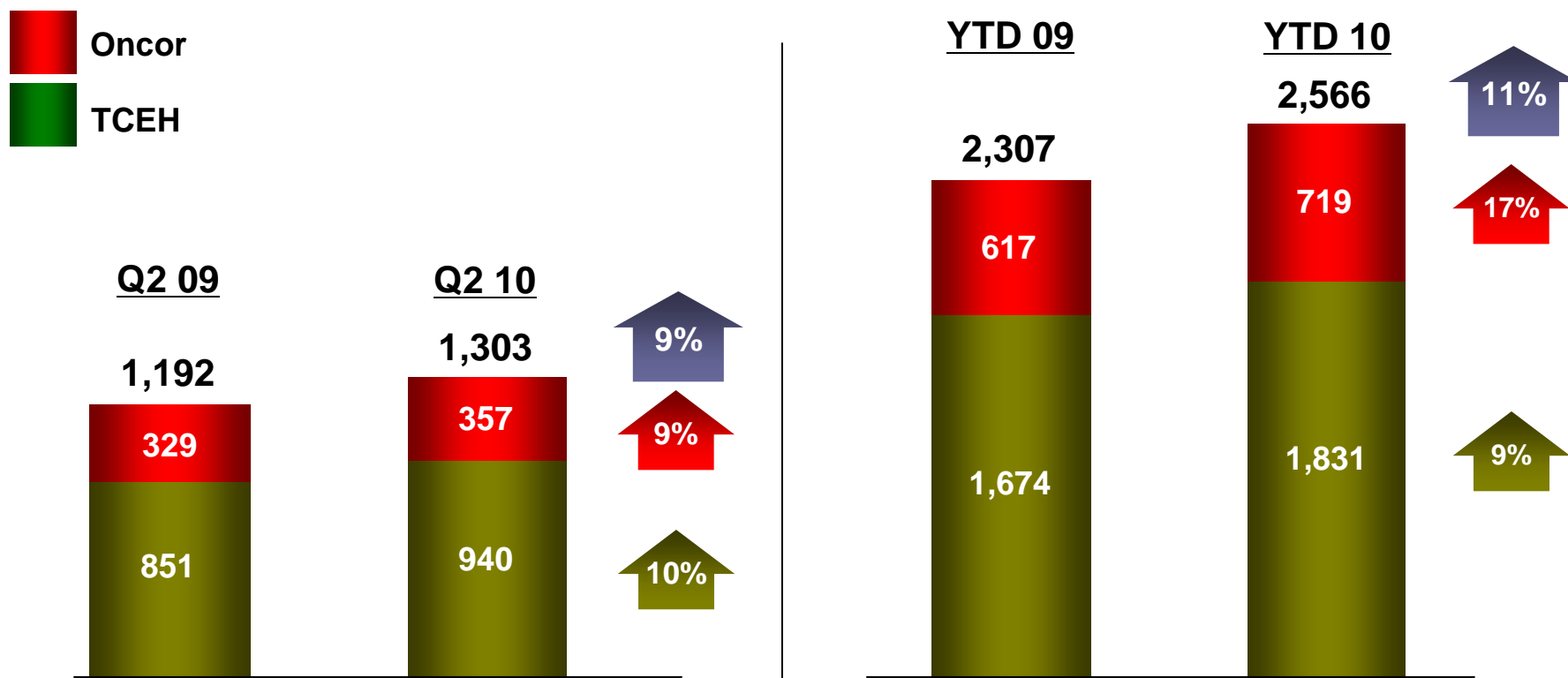
Description/Drivers	Better (Worse) Than YTD 09
<b>Competitive business<sup>2</sup>:</b>	
Impact of new lignite-fueled generation units	122
Lower amortization of intangibles arising from purchase accounting	35
Higher margin from asset management and the retail business	36
Higher retail volumes primarily driven by colder winter weather and improvement in economy	20
Higher fuel expense at the legacy coal-fueled generation units primarily due to increased transportation costs	(45)
Lower production from nuclear fueled generation units due to timing of refueling outage and main transformer replacement	(25)
All Other – net	(2)
Contribution margin	141
Gains on sales of assets (reported in other income)	52
Lower costs related to outsourcing transition and new retail customer care system	29
Higher net interest expense primarily driven by lower capitalized interest due to completion of new generation units	(69)
Higher depreciation reflecting the three new lignite-fueled generation units and mining facilities	(52)
Higher operating costs related to new generation units	(29)
Higher depreciation reflecting ongoing investment in generation fleet	(25)
Higher retail bad debt expense	(10)
All other - net	(2)
Total improvement - Competitive business	35
<b>Regulated business:</b>	
Higher distribution tariffs, including the rates approved in the September 2009 final rate review order	32
Higher average consumption driven by the effect of weather	27
Surcharge to recover AMS deployment costs	19
Higher depreciation reflecting higher depreciation rates approved in the September final rate review order and infrastructure investment	(47)
Higher costs reflecting amortization of regulatory assets approved for recovery, AMS implementation and higher transmission fees	(29)
All other – net (includes noncontrolling interests)	8
Total improvement – Regulated business (80% owned by EFH Corp.)	10
<b>Total change in EFH Corp. adjusted (non-GAAP) operating results</b>	<b>45</b>

<sup>1</sup> Six months ended June 30

<sup>2</sup> Competitive business consists of Competitive Electric segment and Corp. & Other.

# EFH Corp. Adjusted EBITDA (Non-GAAP)

EFH Corp. Adjusted EBITDA (non-GAAP)<sup>1</sup>  
 Q2<sup>2</sup> 09 vs. Q2 10 and YTD<sup>3</sup> 09 vs. YTD 10; \$ millions



*Q2 10 and YTD 10 performance was largely driven by the same key drivers impacting (non-GAAP) operating results.*

<sup>1</sup> See Appendix for Regulation G reconciliations and definition. Includes \$12 million, \$6 million, \$16 million and \$16 million in Q2 09, Q2 10, YTD 09 and YTD 10, respectively, of Corp. & Other Adjusted EBITDA.

<sup>2</sup> Three months ended June 30

<sup>3</sup> Six months ended June 30

# Luminant Operational Results

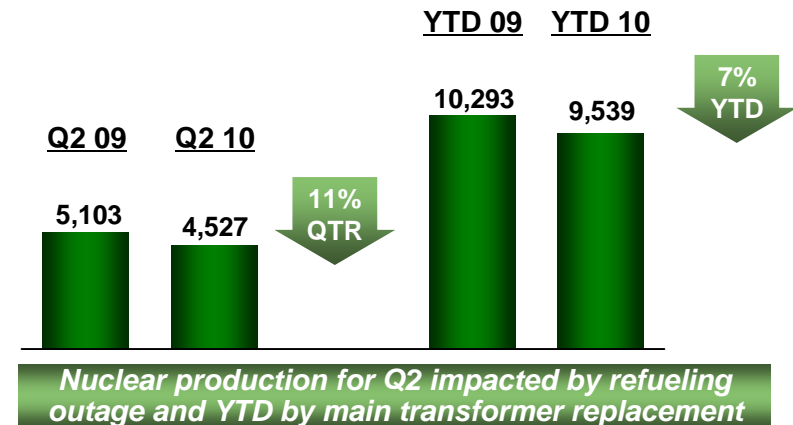


**Luminant**

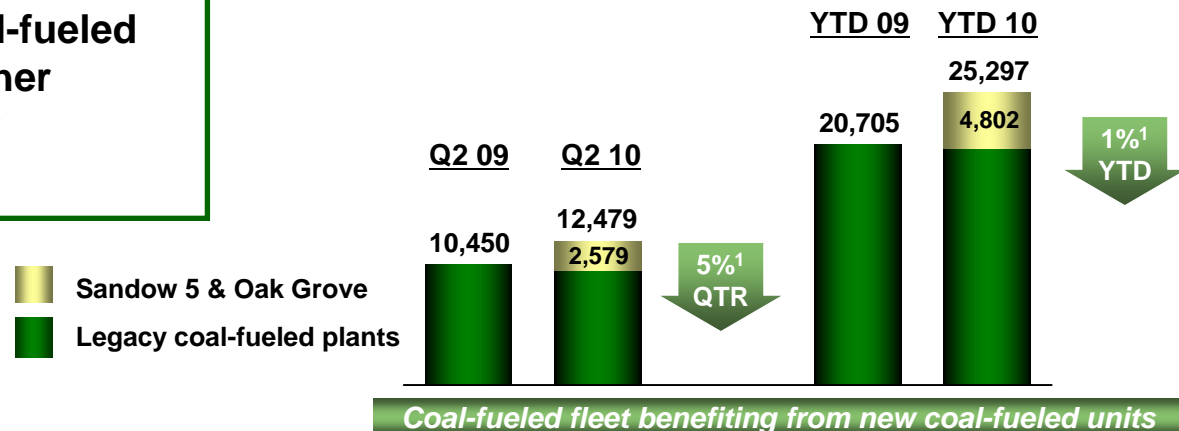
## Q2 10 Results

- Continued strong safety focus and results
- New coal-fueled units added 2.6 TWh of generation in Q2 2010 (4.8 TWh YTD) to the baseload fleet
- Nuclear production impacted by refueling outage in April 2010
- Generation from legacy coal-fueled plants was lower due to higher planned outages and higher economic backdown

## Nuclear-fueled generation; GWh



## Coal-fueled generation; GWh



Sandow 5 & Oak Grove  
 Legacy coal-fueled plants

<sup>1</sup> Variance does not include generation from Sandow 5 and Oak Grove 1 & 2.

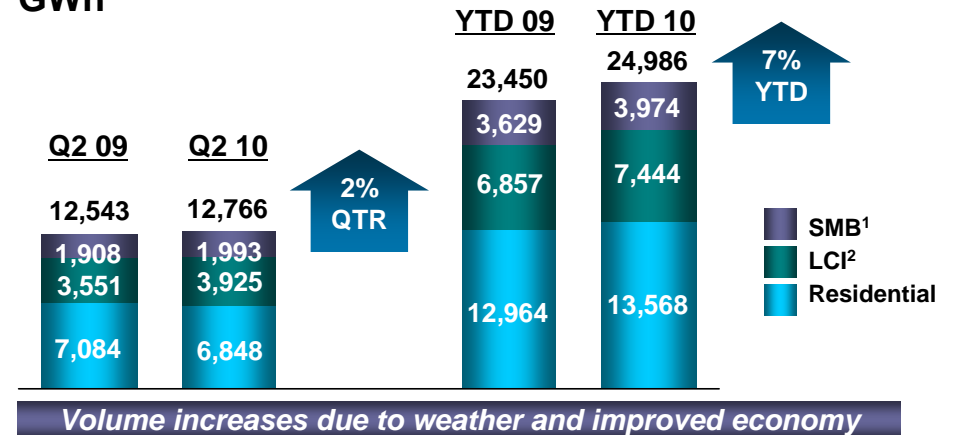
# TXU Energy Operational Results



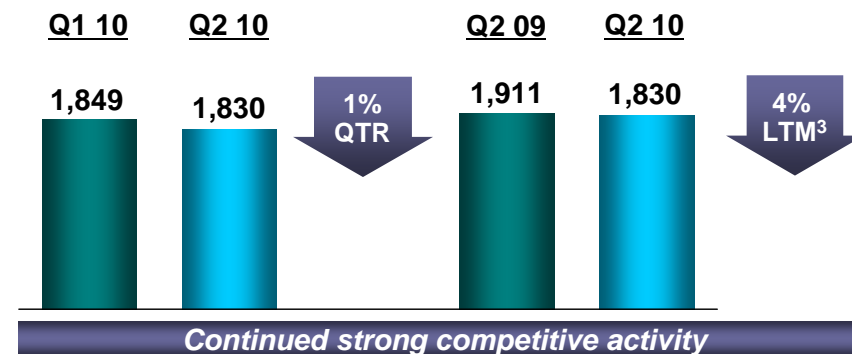
## Q2 10 Results

- Lower residential sales volumes driven by lower customer counts partially offset by slightly warmer weather in Q2 10 compared to Q2 09
- Business load growth attributable to new customers and slightly improved economy
- Lower residential customer counts reflect competitive activity in the marketplace

Retail electricity sales volumes by customer class; GWh



Total residential customers  
End of period, thousands



<sup>1</sup> SMB – small business

<sup>2</sup> LCI - large commercial and industrial

<sup>3</sup> Latest twelve months

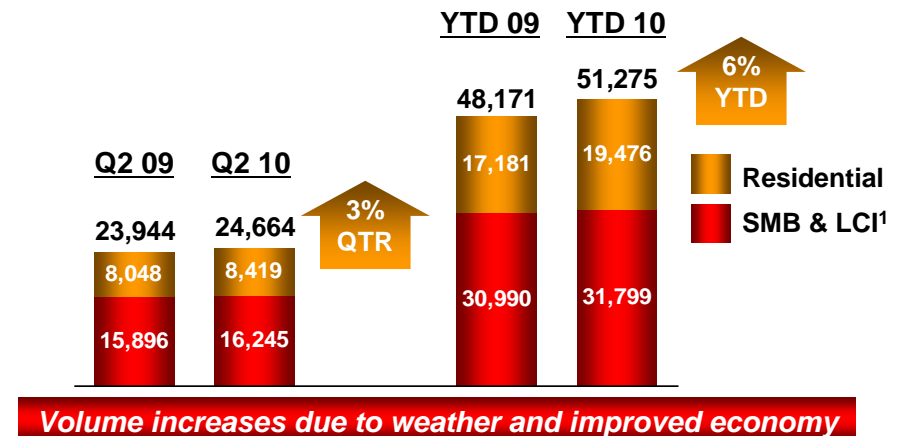
# Oncor Operational Results



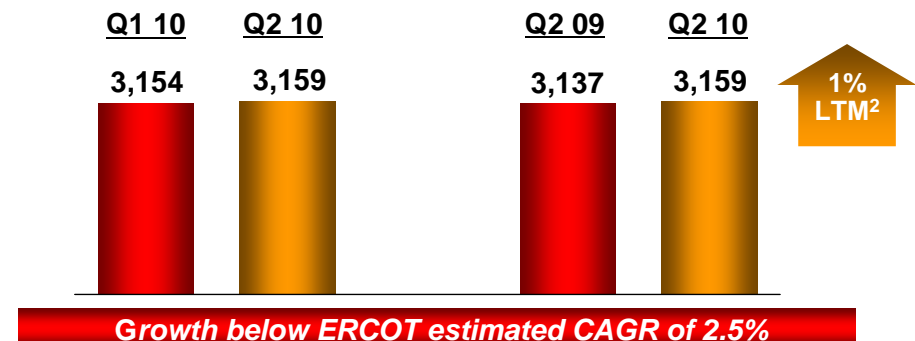
## Q2 10 Results

- Higher residential energy volumes due to marginally warmer weather in Q2 10 compared to Q2 09
- Higher SMB and LCI<sup>1</sup> energy volumes due to a slightly improved economy
- Execution of AMS plan – ~240,000 advanced meters installed during Q2 10; over 1.1 million installed through July 2010
- 9 of 14 CREZ-related Certificates of Convenience and Necessity (CCN) approved by the Public Utility Commission of Texas

## Electric energy volumes; GWh



## Electricity distribution points of delivery End of period, thousands of meters

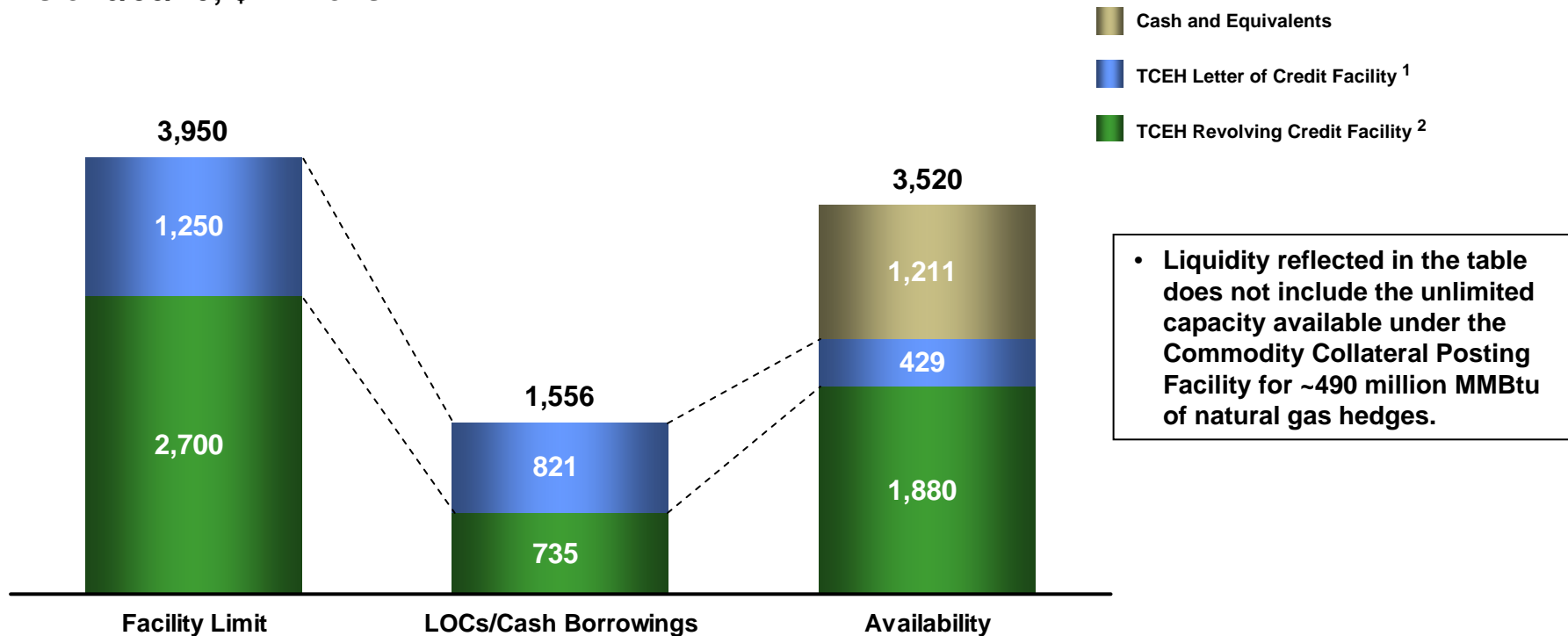


<sup>1</sup> SMB – small business; LCI – large commercial and industrial

<sup>2</sup> Latest twelve months

# EFH Corp. Liquidity Management

EFH Corp. (excluding Oncor) available liquidity  
As of 6/30/10; \$ millions



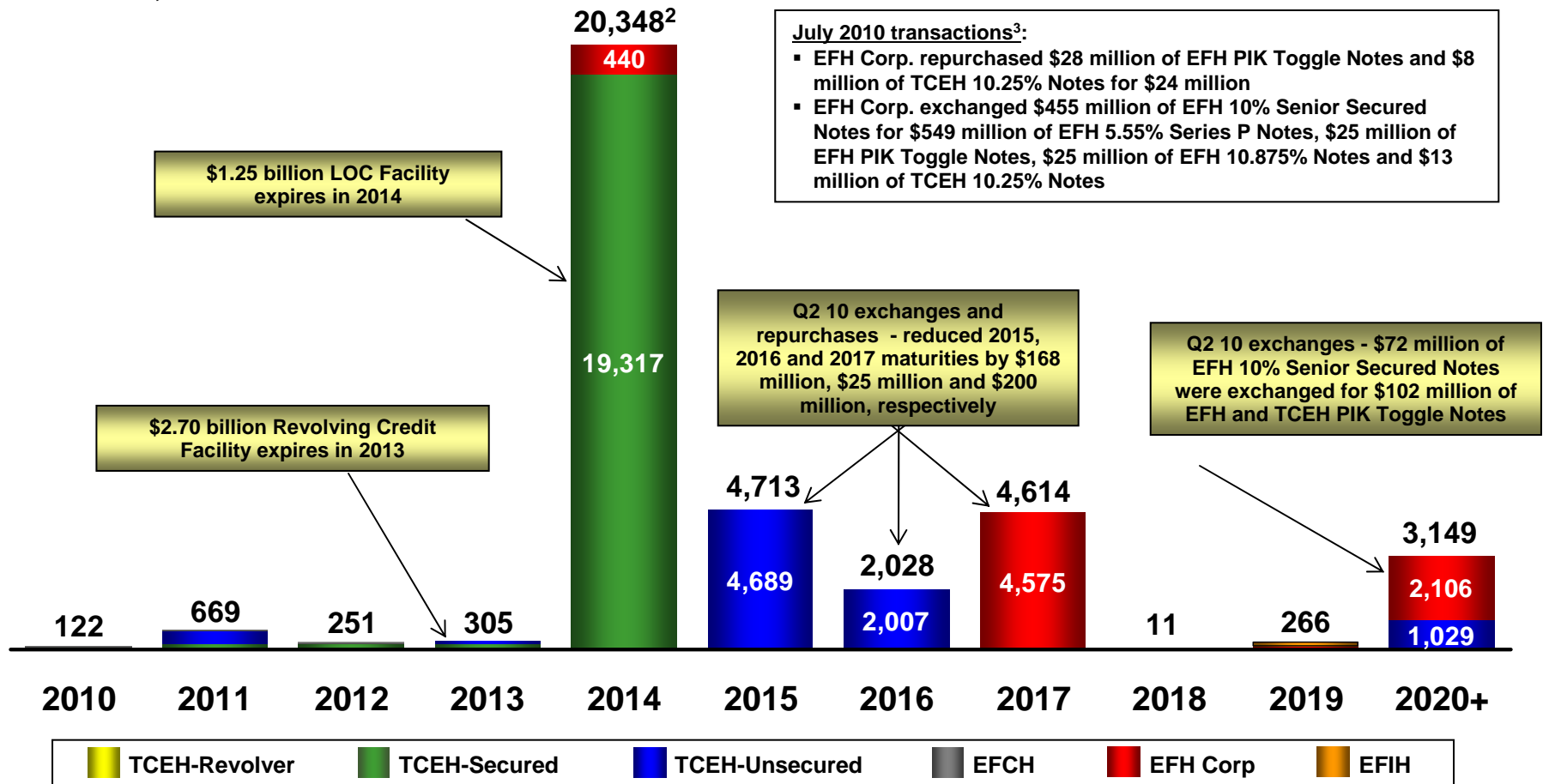
*EFH Corp. and TCEH have sufficient liquidity to meet their anticipated short-term needs, but will continue to monitor market conditions to ensure financial flexibility.*

<sup>1</sup> Facility to be used for issuing letters of credit for general corporate purposes. Cash borrowings of \$1.250 billion were drawn on this facility in October 2007, and except for \$115 million related to a letter of credit drawn in June 2009, have been retained as restricted cash. Outstanding letters of credit are supported by the restricted cash.

<sup>2</sup> Facility availability includes \$144 million of undrawn commitments from a subsidiary of Lehman Brothers that has filed for bankruptcy. These funds are only available from the fronting banks and the swingline lender, and exclude \$85 million of requested draws not funded by the Lehman subsidiary.

# Current Maturity Profile

EFH Corp. debt maturities<sup>1</sup> (excluding Oncor), 2010-2020 and thereafter  
As of 6/30/10; \$ millions



*EFH Corp. continues to explore opportunities to improve the enterprise's maturity profile.*

<sup>1</sup> Includes amortization of the \$4.1 billion Delayed Draw Term Loan.

<sup>2</sup> Excludes borrowings under the TCEH Revolving Credit Facility maturing in 2013, the Deposit Letter of Credit maturing in 2014 and unamortized discounts and premiums.

<sup>3</sup> Does not include the public exchange offer launched on July 16, 2010, which expires on August 12, 2010.

# Today's Agenda

**Financial and Operational  
Overview**

**Q2 2010 Review**

**John Young  
President & CEO**

**Q&A**


# Today's Agenda

**Financial and Operational  
Overview**

**Q2 2010 Review**

**Q&A**

**EFH Corp. Senior Executive Team**



# Questions & Answers

# Appendix

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## **Appendix – Additional Slides and Regulation G Reconciliations**

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# Luminant Solid-Fuel Development Program



**Luminant**

## Sadow Power Plant Unit 5 Rockdale, Texas



## Oak Grove Power Plant Robertson County, Texas



Estimated net capacity	~580 MW
Primary fuel	Texas lignite
Initial synchronization	July 2009
Substantial completion date <sup>1</sup>	September 2009

	Unit 1	Unit 2
Estimated net capacity	~800 MW	~800 MW
Primary fuel	Texas lignite	Texas lignite
Initial synchronization	August 2009	January 2010
Substantial completion date <sup>1</sup>	December 2009	June 2010

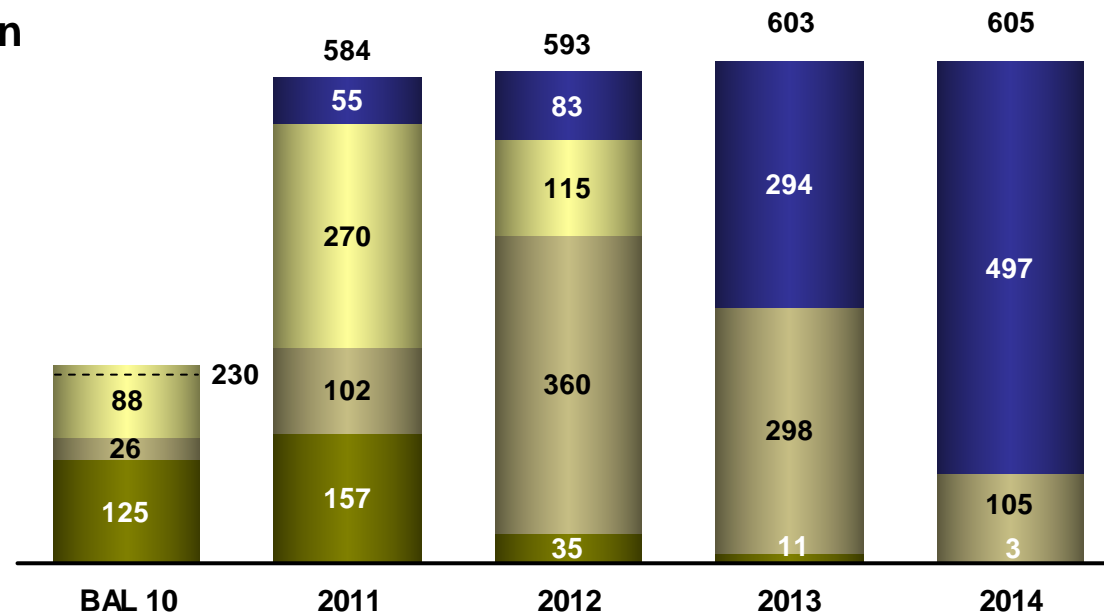
- Both Sadow 5 and Oak Grove 1 lignite-fueled generating units achieved 70% average capacity factors during the first quarter of 2010.
- Luminant's construction of the Oak Grove 2 lignite-fueled generating unit reached substantial completion on June 1, 2010

<sup>1</sup> Substantial completion date is the contractual milestone when Luminant takes over operations of the unit from the EPC contractor.

# TCEH Natural Gas Exposure

## TCEH Natural Gas Position 10-14<sup>1</sup>; million MMBtu

- Open Position
- Hedges Backed by CCP
- Hedges Backed by Asset First Lien
- TXUE and Luminant Net Positions<sup>2</sup>
- 100% Hedge Level



Factor	Measure	BAL 10	2011	2012	2013	2014	Total or Average
Natural gas hedging program	million MMBtu	~114	~372	~475	~298	~105	~1,364
TXUE and Luminant net positions	million MMBtu	~125	~157	~35	~11	~3	~331
Overall estimated percent of total NG position hedged	percent	~104%	~91%	~86%	~51%	~18%	~65%

***TCEH has hedged approximately 65% of its estimated Henry Hub-based natural gas price exposure from August 1, 2010 through December 31, 2014. More than 95% of the NG Hedges are supported directly by a first lien or by the TCEH Commodity Collateral Posting Facility.***

<sup>1</sup> As of 6/30/10. Balance of 2010 is from August 1, 2010 to December 31, 2010. Assumes conversion of electricity positions based on a ~8.0 heat rate with natural gas being on the margin ~75-90% of the time (i.e. when other technologies are forecast to be on the margin, no natural gas position is assumed to be generated).

<sup>2</sup> Includes estimated retail/wholesale effects. 2010 position includes ~4 million MMBtu of short gas positions associated with proprietary trading positions; excluding these positions, 2010 position is ~102% hedged.

# Unrealized Mark-To-Market Impact Of Hedging

## Unrealized mark-to-market impact of hedging program 6/30/10 vs. 3/31/10; mixed measures, pre-tax

Factor	Measure	2010	2011	2012	2013	2014	Total or Avg.
<b>3/31/10</b>							
Natural gas hedges	mm MMBtu	~181	~424	~487	~300	~99	~1,491
Wtd. avg. hedge price <sup>1</sup>	\$/MMBtu	~\$7.71	~\$7.56	~\$7.36	~\$7.19	~\$7.80	
Natural gas prices	\$/MMBtu	~\$4.27	~\$5.34	~\$5.79	~\$6.07	~\$6.36	
Cum. MtM gain at 3/31/10 <sup>2</sup>	\$ billions	~\$0.8	~\$0.9	~\$0.8	~\$0.3	~\$0.3	~\$3.1
<b>6/30/10</b>							
Natural gas hedges <sup>3</sup>	mm MMBtu	~126	~372	~475	~298	~105	~1,376
Wtd. avg. hedge price <sup>1</sup>	\$/MMBtu	~\$7.75	~\$7.53	~\$7.34	~\$7.18	~\$7.80	
Natural gas prices	\$/MMBtu	~\$4.82	~\$5.34	~\$5.68	~\$5.89	~\$6.10	
Cum. MtM gain at 6/30/10 <sup>2</sup>	\$ billions	~\$0.5	~\$0.9	~\$0.8	~\$0.4	~\$0.3	~\$2.9
<b>Q2 10 MtM gain</b>	<b>\$ billions</b>	<b>~(\$0.3)</b>	<b>~\$0</b>	<b>~\$0</b>	<b>~\$0.1</b>	<b>~\$0</b>	<b>~(\$0.2)</b>

*Reversals of prior unrealized gains for positions settled during the second quarter of 2010 more than offset gains in the forward years of the hedge program, resulting in a ~\$170 million (~\$110 million after tax) unrealized mark-to-market net loss in GAAP income for Q2 10.*

<sup>1</sup> Weighted average prices are based on NYMEX Henry Hub prices of forward natural gas sales positions in the long-term hedging program (excluding the impact of offsetting purchases for rebalancing and pricing point basis transactions). Where collars are reflected, sales price represents the collar floor price. 6/30/10 prices for 2010 represent July 1, 2010 through December 31, 2010 values.

<sup>2</sup> MtM values include the effects of all transactions in the long-term hedging program including offsetting purchases (for re-balancing) and natural gas basis deals.

<sup>3</sup> As of 6/30/10, 2010 represents July 1, 2010 through December 31, 2010 volumes. Where collars are reflected, the volumes are estimated based on the natural gas price sensitivity (i.e., delta position) of the derivatives. The notional volumes for collars are approximately 150 million MMBtu, which corresponds to a delta position of approximately 105 million MMBtu in 2014. **19**

# Unrealized Mark-To-Market Impact Of Hedging

## Unrealized mark-to-market impact of hedging program 6/30/10 vs. 12/31/09; mixed measures, pre-tax

Factor	Measure	2010	2011	2012	2013	2014	Total or Avg.
<b>12/31/09</b>							
Natural gas hedges	mm MMBtu	~240	~447	~490	~300	~97	~1,574
Wtd. avg. hedge price <sup>1</sup>	\$/MMBtu	~\$7.79	~\$7.56	~\$7.36	~\$7.19	~\$7.80	
Natural gas prices	\$/MMBtu	~\$5.79	~\$6.34	~\$6.53	~\$6.67	~\$6.84	
Cum. MtM gain at 12/31/09 <sup>2</sup>	\$ billions	~\$0.8	~\$0.4	~\$0.4	~\$0.2	~\$0.2	~\$2.0
<b>6/30/10</b>							
Natural gas hedges <sup>3</sup>	mm MMBtu	~126	~372	~475	~298	~105	~1,376
Wtd. avg. hedge price <sup>1</sup>	\$/MMBtu	~\$7.75	~\$7.53	~\$7.34	~\$7.18	~\$7.80	
Natural gas prices	\$/MMBtu	~\$4.82	~\$5.34	~\$5.68	~\$5.89	~\$6.10	
Cum. MtM gain at 6/30/10 <sup>2</sup>	\$ billions	~\$0.5	~\$0.9	~\$0.8	~\$0.4	~\$0.3	~\$2.9
YTD MtM gain	\$ billions	~(0.3)	~\$0.5	~\$0.4	~\$0.2	~\$0.1	~\$0.9

*Decreases in natural gas prices during the first six months of 2010 resulted in a ~\$890 million (~\$570 million after tax) unrealized mark-to-market net gain in GAAP income for YTD 10.*

<sup>1</sup> Weighted average prices are based on NYMEX Henry Hub prices of forward natural gas sales positions in the long-term hedging program (excluding the impact of offsetting purchases for rebalancing and pricing point basis transactions). Where collars are reflected, sales price represents the collar floor price. 6/30/10 prices for 2010 represent July 1, 2010 through December 31, 2010 values.

<sup>2</sup> MtM values include the effects of all transactions in the long-term hedging program including offsetting purchases (for re-balancing) and natural gas basis deals.

<sup>3</sup> As of 6/30/10, 2010 represents July 1, 2010 through December 31, 2010 volumes. Where collars are reflected, the volumes are estimated based on the natural gas price sensitivity (i.e., delta position) of the derivatives. The notional volumes for collars are approximately 150 million MMBtu, which corresponds to a delta position of approximately 105 million MMBtu in 2014. **20**

# EFH Corp. Adjusted EBITDA Sensitivities

## Impact on EFH Corp. Adjusted EBITDA<sup>1</sup> 10E; mixed measures

Commodity	Percent Hedged at June 30, 2010	Change	BOY 10E Impact \$ millions
7X24 market heat rate (MMBtu/MWh) <sup>2</sup>	~85	0.1 MMBtu/MWh	~3
NYMEX gas price (\$/MMBtu) <sup>3</sup>	~100	\$1/MMBtu	~9
Texas gas vs. NYMEX Henry Hub price (\$/MMBtu) <sup>3,4</sup>	>95	\$0.10/MMBtu	~0
Diesel (\$/gallon) <sup>5</sup>	~100	\$1/gallon	~1
Base coal (\$/ton) <sup>6</sup>	~100	\$5/ton	~2
<b>Generation operations</b>			
Baseload generation (TWh)	n.a.	1 TWh	~25
<b>Retail operations</b>			
Balance of 2010			
Residential contribution margin (\$/MWh)	14 TWh	\$1/MWh	~14
Residential consumption	14 TWh	1%	~5
Business markets consumption	13 TWh	1%	~2

*The majority of 2010 commodity-related risks are significantly mitigated.*

<sup>1</sup> 2010 estimate based on commodity positions as of 6/30/10, net of long-term hedges and wholesale/retail effects, excludes gains and losses incurred prior to June 30, 2010. See Appendix for definition.

<sup>2</sup> Simplified representation of heat rate position in a single TWh position. In reality, heat rate impacts are differentiated across plants and respective pricing periods: baseload (linked primarily to changes in North Zone 7x24), natural gas plants (primarily North Zone 5x16) and wind (primarily West Zone 7x8).

<sup>3</sup> Assumes conversion of electricity positions based on a ~8.0 market heat rate with natural gas being on the margin ~75-90% of the time (i.e., when coal is forecast to be on the margin, no natural gas position is assumed to be generated).

<sup>4</sup> The percentage hedged represents the amount of estimated natural gas exposure based on Houston Ship Channel (HSC) gas price sensitivity as a proxy for Texas gas price.

<sup>5</sup> Includes positions related to fuel surcharge on rail transportation.

<sup>6</sup> Excludes fuel surcharge on rail transportation.

# Commodity Prices

## Commodity prices Q2 09, Q2 10, YTD 10 and BOY 10E; mixed measures

Commodity	Units	Q2 09 Actual	Q2 10 Actual	YTD 10 Actual	BOY 10E <sup>1</sup>
NYMEX gas price <sup>2</sup>	\$/MMBtu	\$3.69	\$4.30	\$4.72	\$4.82
HSC gas price	\$/MMBtu	\$3.57	\$4.25	\$4.67	\$4.66
7x24 market heat rate (HSC) <sup>3</sup>	MMBtu/MWh	8.08	8.17	7.93	8.16
North Zone 7x24 power price	\$/MWh	\$28.82	\$34.85	\$37.02	\$37.99
TCEH weighted avg. hedge price <sup>4</sup>	\$/MMBtu	\$8.11	\$7.51	\$7.78	\$7.75
Gulf Coast ultra-low sulfur diesel	\$/gallon	\$1.57	\$2.14	\$2.10	\$2.09
PRB 8400 coal	\$/ton	\$7.61	\$9.59	\$8.84	\$9.69
LIBOR interest rate <sup>5</sup>	percent	1.39%	0.63%	0.51%	0.75%

<sup>1</sup> BOY 10 estimate based on commodity prices as of 6/30/10 for July 1, 2010 through December 31, 2010

<sup>2</sup> Based on NYMEX forward curve

<sup>3</sup> Based on market clearing price for power

<sup>4</sup> Weighted average prices in the TCEH long-term natural gas hedging program. Based on NYMEX Henry Hub prices of forward natural gas sales positions in the long-term hedging program (excluding the impact of offsetting purchases for rebalancing and pricing point basis transactions).

<sup>5</sup> The index for the settled value is a 6 month LIBOR rate.

# Financial Definitions

Measure	Definition
GAAP	Generally accepted accounting principles.
Adjusted (non-GAAP) Operating Results	Net income (loss) adjusted for items representing income or losses that are not reflective of underlying operating results. These items include unrealized mark-to-market gains and losses, noncash impairment charges and other charges, credits or gains that are unusual or nonrecurring. EFH Corp. uses adjusted (non-GAAP) operating earnings as a measure of performance and believes that analysis of its business by external users is enhanced by visibility to both net income (loss) prepared in accordance with GAAP and adjusted (non-GAAP) operating earnings (losses).
Competitive Business Results	Refers to the combined results of the Competitive Electric segment and Corporate & Other.
Regulated Business Results	Refers to the results of Oncor and the Oncor ring-fenced entities.
Contribution Margin (non-GAAP)	Operating revenues less fuel, purchased power costs, and delivery fees, plus or minus net gain (loss) from commodity hedging and trading activities, which on an adjusted (non-GAAP) basis, exclude unrealized gains and losses.
EBITDA (non-GAAP)	Net income (loss) from continuing operations before interest expense and related charges, and income tax expense (benefit) plus depreciation and amortization.
Adjusted EBITDA (non-GAAP)	EBITDA adjusted to exclude interest income, noncash items, unusual items, interest income, income from discontinued operations and other adjustments allowable under the EFH Corp. senior and senior secured notes indentures. Adjusted EBITDA plays an important role in respect of certain covenants contained in these indentures. Adjusted EBITDA is not intended to be an alternative to GAAP results as a measure of operating performance or an alternative to cash flows from operating activities as a measure of liquidity or an alternative to any other measure of financial performance presented in accordance with GAAP, nor is it intended to be used as a measure of free cash flow available for EFH Corp.'s discretionary use, as the measure excludes certain cash requirements such as interest payments, tax payments and other debt service requirements. Because not all companies use identical calculations, Adjusted EBITDA may not be comparable to similarly titled measures of other companies.
Purchase Accounting	The purchase method of accounting for a business combination as prescribed by GAAP, whereby the purchase price of a business combination is allocated to identifiable assets and liabilities (including intangible assets) based upon their fair values. The excess of the purchase price over the fair values of assets and liabilities is recorded as goodwill. Depreciation and amortization due to purchase accounting represents the net increase in such noncash expenses due to recording the fair market values of property, plant and equipment, debt and other assets and liabilities, including intangible assets such as emission allowances, customer relationships and sales and purchase contracts with pricing favorable to market prices at the date of the Merger. Amortization is reflected in revenues, fuel, purchased power costs and delivery fees, depreciation and amortization and interest expense in the income statement.

**Table 1: EFH Corp. Adjusted EBITDA Reconciliation**  
**Three and Six Months Ended June 30, 2009 and 2010**  
**\$ millions**

<b>Factor</b>	<b>Q2 09</b>	<b>Q2 10</b>	<b>YTD 09</b>	<b>YTD 10</b>
Net income (loss) attributable to EFH Corp.	(155)	(426)	287	(71)
Income tax expense (benefit)	(48)	(237)	285	(35)
Interest expense and related charges	431	1,122	1,096	2,074
Depreciation and amortization	423	350	830	692
<b>EBITDA</b>	<b>651</b>	<b>809</b>	<b>2,498</b>	<b>2,660</b>
<b>Adjustments to EBITDA (pre-tax):</b>				
Oncor EBITDA	(338)	-	(636)	-
Oncor distributions/dividends	51	57	75	87
Interest income	(11)	-	(12)	(9)
Amortization of nuclear fuel	24	27	48	64
Purchase accounting adjustments <sup>1</sup>	83	58	180	114
Impairment of goodwill <sup>2</sup>	-	-	90	-
Impairment of assets and inventory write-down	1	2	2	2
Net gain on debt exchange offers	-	(129)	-	(143)
Net income attributable to noncontrolling interests	16	-	28	-
Equity in earnings of unconsolidated subsidiary	-	(59)	-	(122)
EBITDA amount attributable to consolidated unrestricted subsidiaries	1	-	2	-
Unrealized net (gain) loss resulting from hedging transactions	320	145	(710)	(848)
Amortization of "day one" net loss on Sandow 5 power purchase agreement	-	(5)	-	(11)
Losses on sale of receivables	3	-	7	-

Note: Table and footnotes to this table continue on following page

**Table 1: EFH Adjusted EBITDA Reconciliation (continued from previous page)**  
**Three and Six Months Ended June 30, 2009 and 2010**  
**\$ millions**

Factor	Q2 09	Q2 10	YTD 09	YTD 10
Noncash compensation expense <sup>3</sup>	6	4	12	13
Severance expense <sup>4</sup>	1	-	8	3
Transition and business optimization costs <sup>5</sup>	8	-	19	-
Transaction and merger expenses <sup>6</sup>	25	11	42	24
Restructuring and other	6	6	12	-
Expenses incurred to upgrade or expand a generation station <sup>7</sup>	66	77	100	100
<b>EFH Corp. Adjusted EBITDA per Incurrence Covenant</b>	<b>913</b>	<b>1,003</b>	<b>1,765</b>	<b>1,934</b>
<b>Add back Oncor adjustments</b>	<b>279</b>	<b>300</b>	<b>542</b>	<b>632</b>
<b>EFH Corp. Adjusted EBITDA per Restricted Payments Covenant</b>	<b>1,192</b>	<b>1,303</b>	<b>2,307</b>	<b>2,566</b>

<sup>1</sup> Includes amortization of the intangible net asset value of retail and wholesale power sales agreements, environmental credits, coal purchase contracts, nuclear fuel contracts and power purchase agreements and the stepped-up value of nuclear fuel. Also includes certain credits not recognized in net income due to purchase accounting.

<sup>2</sup> Reflects the completion in the first quarter of 2009 of the fair value calculation supporting the goodwill impairment charge that was recorded in the fourth quarter of 2008.

<sup>3</sup> Accounted for under accounting standards related to stock compensation and excludes capitalized amounts.

<sup>4</sup> Includes amounts incurred related to outsourcing, restructuring and other amounts deemed to be in excess of normal recurring amounts.

<sup>5</sup> Includes professional fees primarily for retail billing and customer care systems enhancements and certain incentive compensation.

<sup>6</sup> Includes costs related to the Merger and abandoned strategic transactions, outsourcing transition costs, administrative costs related to the cancelled program to develop coal-fueled facilities, the Sponsor Group management fee, costs related to certain growth initiatives and costs related to the Oncor sale of noncontrolling interests.

<sup>7</sup> Reflects noncapital outage costs.

**Table 2: TCEH Adjusted EBITDA Reconciliation**  
**Three and Six Months Ended June 30, 2009 and 2010**  
**\$ millions**

<b>Factor</b>	<b>Q2 09</b>	<b>Q2 10</b>	<b>YTD 09</b>	<b>YTD 10</b>
Net income (loss)	(59)	(406)	517	43
Income tax expense (benefit)	(26)	(212)	341	46
Interest expense and related charges	164	915	562	1,664
Depreciation and amortization	283	344	559	681
<b>EBITDA</b>	<b>362</b>	<b>641</b>	<b>1,979</b>	<b>2,434</b>
<b>Adjustments to EBITDA (pre-tax):</b>				
Interest income	(12)	(21)	(19)	(42)
Amortization of nuclear fuel	24	27	48	64
Purchase accounting adjustments <sup>1</sup>	71	47	157	91
Impairment of goodwill <sup>2</sup>	-	-	70	-
Impairment of assets and inventory writedown	-	1	-	1
EBITDA amount attributable to consolidated unrestricted subsidiaries	-	-	2	-
Unrealized net (gain) loss resulting from hedging transactions	320	145	(710)	(848)
Amortization of "day one" net loss on Sandow 5 power purchase agreement	-	(5)	-	(11)
Corp. depreciation, interest and income tax expense included in SG&A	-	3	-	5
Losses on sale of receivables	3	-	7	-
Noncash compensation expense <sup>3</sup>	2	3	4	10
Severance expense <sup>4</sup>	1	-	8	3
Transition and business optimization costs <sup>5</sup>	8	1	19	2
Transaction and merger expenses <sup>6</sup>	1	10	2	21

Note: Table and footnotes to this table continue on following page

**Table 2: TCEH Adjusted EBITDA Reconciliation (continued from previous page)**  
**Three and Six Months Ended June 30, 2009 and 2010**  
**\$ millions**

<b>Factor</b>	<b>Q2 09</b>	<b>Q2 10</b>	<b>YTD 09</b>	<b>YTD 10</b>
<b>Restructuring and other</b>	<b>5</b>	<b>11</b>	<b>7</b>	<b>1</b>
<b>Expenses incurred to upgrade or expand a generation station<sup>7</sup></b>	<b>66</b>	<b>77</b>	<b>100</b>	<b>100</b>
<b>TCEH Adjusted EBITDA per Incurrence Covenant</b>	<b>851</b>	<b>940</b>	<b>1,674</b>	<b>1,831</b>
<b>Expenses related to unplanned generation station outages<sup>7</sup></b>	<b>15</b>	<b>32</b>	<b>48</b>	<b>91</b>
<b>Other adjustments allowed to determine Adjusted EBITDA per Maintenance Covenant<sup>8</sup></b>	<b>7</b>	<b>4</b>	<b>12</b>	<b>9</b>
<b>TCEH Adjusted EBITDA per Maintenance Covenant</b>	<b>873</b>	<b>976</b>	<b>1,734</b>	<b>1,931</b>

<sup>1</sup> Includes amortization of the intangible net asset value of retail and wholesale power sales agreements, environmental credits, coal purchase contracts, nuclear fuel contracts and power purchase agreements and the stepped up value of nuclear fuel. Also includes certain credits not recognized in net income due to purchase accounting.

<sup>2</sup> Reflects the completion in the first quarter of 2009 of the fair value calculation supporting the goodwill impairment charge that was recorded in the fourth quarter of 2008.

<sup>3</sup> Excludes capitalized amounts.

<sup>4</sup> Includes amounts incurred related to outsourcing, restructuring and other amounts deemed to be in excess of normal recurring amounts.

<sup>5</sup> Includes professional fees primarily for retail billing and customer care systems enhancements and certain incentive compensation.

<sup>6</sup> Includes costs related to the Merger, outsourcing transition costs and costs related to certain growth initiatives.

<sup>7</sup> Reflects noncapital outage costs.

<sup>8</sup> Primarily pre-operating expenses related to Oak Grove and Sandow 5 generation facilities.

**Table 3: Oncor Adjusted EBITDA Reconciliation**  
**Three and Six Months Ended June 30, 2009 and 2010**  
**\$ millions**

<b>Factor</b>	<b>Q2 09</b>	<b>Q2 10</b>	<b>YTD 09</b>	<b>YTD 10</b>
<b>Net income</b>	<b>82</b>	<b>76</b>	<b>140</b>	<b>155</b>
<b>Income tax expense</b>	<b>48</b>	<b>47</b>	<b>85</b>	<b>96</b>
<b>Interest expense and related charges</b>	<b>87</b>	<b>86</b>	<b>171</b>	<b>170</b>
<b>Depreciation and amortization</b>	<b>132</b>	<b>164</b>	<b>258</b>	<b>331</b>
<b>EBITDA</b>	<b>349</b>	<b>373</b>	<b>654</b>	<b>752</b>
<b>Interest income</b>	<b>(10)</b>	<b>(9)</b>	<b>(19)</b>	<b>(19)</b>
<b>Purchase accounting adjustments<sup>1</sup></b>	<b>(10)</b>	<b>(9)</b>	<b>(20)</b>	<b>(18)</b>
<b>Restructuring and other</b>	<b>-</b>	<b>2</b>	<b>2</b>	<b>4</b>
<b>Oncor Adjusted EBITDA</b>	<b>329</b>	<b>357</b>	<b>617</b>	<b>719</b>

<sup>1</sup> Purchase accounting adjustments consist of amounts related to the accretion of an adjustment (discount) to regulatory assets resulting from purchase accounting.