Operations Report (Feb & Mar 2012)
Board of Directors Meeting
April 16-17, 2012

Trip Doggett
President & CEO

Summary – February 2012

- **Operations**
  - The peak demand of 42,035 MW on February 13th was greater than the mid-term forecast peak of 41,560 MW and less than the February 2011 actual peak demand of 57,315 MW.
  - Day-ahead load forecast error for February was 2.51%
  - No Reliability Unit Commitments (RUC) in February. First month in nodal operations RUC not needed.
  - Advisory for Physical Responsive Capability (PRC) below 3000 MW was issued for 9 days
  - No Watches for PRC under 2500 MW issued
  - No Energy Emergency Alert (EEA) events issued

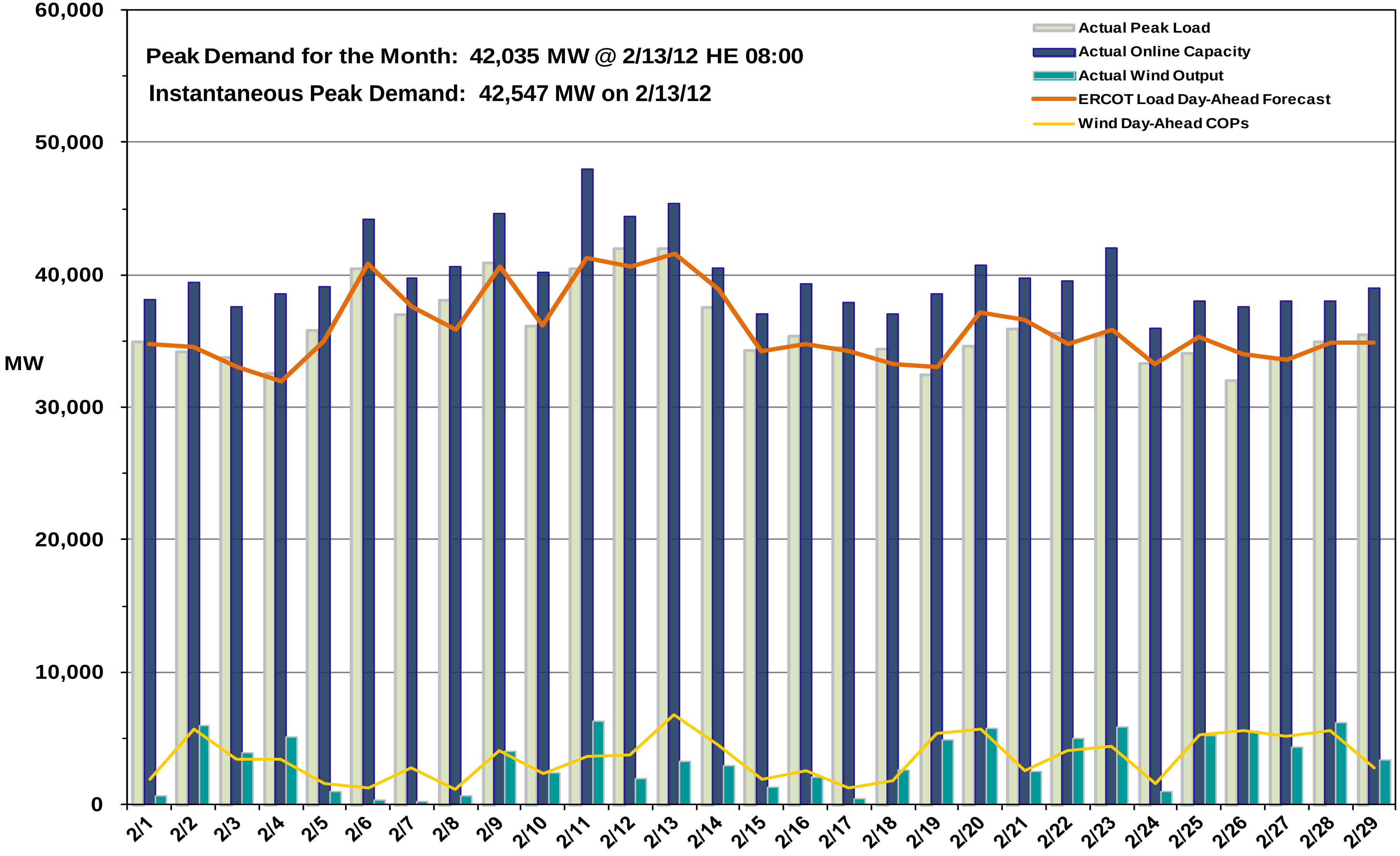
- **Planning Activities**
  - 127 active generation interconnect requests totaling almost 34,000 MW as of February 29, 2012. Three more requests and 1,000 MW more than January 31, 2012
  - 9,838 MW wind capacity on line February 29, 2012; 9 MW more than January 31, 2012.

Summary – March 2012

- **Operations**
  - The peak demand of 41,289 MW on March 26th was greater than the mid-term forecast peak of 38,589 MW and more than the March 2011 actual peak demand of 40,220 MW.
  - Day-ahead load forecast error for March was 3.49%, higher than average due to a number of weather fronts
  - Advisory for Physical Responsive Capability (PRC) below 3000 MW was issued for 13 days
  - One Watch for PRC under 2500 MW issued on March 9
  - No Energy Emergency Alert (EEA) events issued

- **Planning Activities**
  - 128 active generation interconnect requests totaling over 34,000 MW as of March 31, 2012.   One more request and nearly the same MW as February 29, 2012.
  - 9,838 MW wind capacity on line March 31, 2012, No change from February 29, 2012.

February 2012 Daily Peak Demand: Hourly Average Actual vs. Forecast, Wind Day-Ahead COPs & On-line Capacity at Peak



Note: All data are hourly averages during the peak load hour obtained from COPs, and EMMS.

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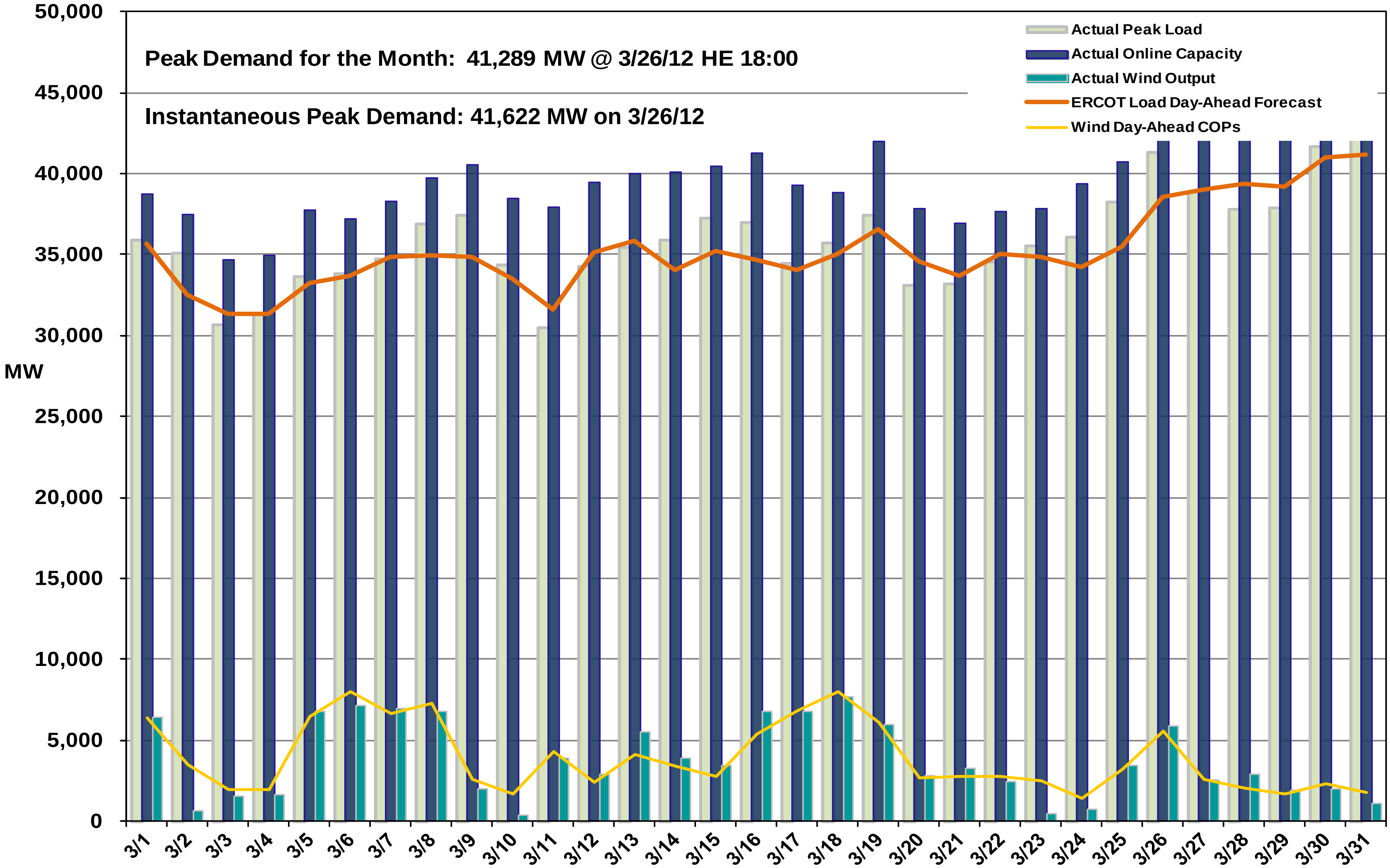

Note: All data are hourly averages during the peak load hour obtained from COPs, and EMMS.

Market Statistics – February 2012

Market Statistics	Feb-11	Feb-12	2011 Average	2012 YTD Average
Percentage of Real-Time load hedged in Day-Ahead Market	113.14%	130.07%	115.13%	131.80%
Average 'ERCOT Hub Average 345 kV Hub' Settlement Point Price in Day-Ahead Market ($/MWh)	61.74	21.09	55.19	21.89
Average 'ERCOT Hub Average 345 kV Hub' Settlement Point Price in Real-Time ($/MWh)	72.17	18.92	50.83	20.41

Market Statistics – March 2012

Market Statistics	Mar-11	Mar-12	2011 Average	2012 YTD Average
Percentage of Real-Time load hedged in Day-Ahead Market	117.85%	124.25%	115.13%	129.28%
Average ‘ERCOT Hub Average 345 kV Hub’ Settlement Point Price in Day-Ahead Market ($/MWh)	28.26	23.24	55.19	22.35
Average ‘ERCOT Hub Average 345 kV Hub’ Settlement Point Price in Real-Time ($/MWh)	26.38	29.83	50.83	23.61

Operational Performance Measures – February 2012

Performance Measure	Target Met	Further Information
Retail Transaction Performance *(Target 98%)*	*Yes*	• Retail transaction processing for all transaction types is above target
Settlements Performance *(Target 99%)*	*Yes*	• 100% timely statement and invoice posting

Operational Performance Measures – March 2012

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Operational Dashboard – February 2012

Metric	Trending as Expected	Further Information
Day-Ahead Schedule	*Yes*	• Normal level of market activity and liquidity • Loads appear to have hedged against exposure to Real-Time prices
Day-Ahead Electricity And Ancillary Service Hourly Average Prices	*Yes*	• Hourly average prices correctly reflect the opportunity cost of energy
Day-Ahead vs Real-Time Load Zone Settlement Point Price (Hourly Average)	*Yes*	• Day-Ahead & Real-Time prices for different Load Zones reflect relative transmission congestion
Day-Ahead vs Real-Time Trading Hub Settlement Point Price (Hourly Average)	*Yes*	• The average energy price across the system reflects marginal offers and scarcity pricing impacts • Higher average Day-Ahead energy prices reflect the risk premium between Day-Ahead & Real-Time
Day-Ahead Reliability Unit (DRUC) Commitment Monthly Summary	*Yes*	• Capacity committed by the DRUC process indicates the level of out of market activity needed Day-Ahead to maintain reliability • This month, no resources were committed for either transmission or capacity

Operational Dashboard – March 2012

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Day-Ahead Electricity And Ancillary Service Hourly Average Prices	*Yes*	• Hourly average prices correctly reflect the opportunity cost of energy
Day-Ahead vs Real-Time Load Zone Settlement Point Price (Hourly Average)	*Yes*	• Day-Ahead & Real-Time prices for different Load Zones reflect relative transmission congestion
Day-Ahead vs Real-Time Trading Hub Settlement Point Price (Hourly Average)	***No***	• Average Real-Time energy prices were higher than Day-Ahead mainly due to - Local congestion caused by transmission outages and low wind in the West Zone during the last week - Scarcity during peak hours on two days
Day-Ahead Reliability Unit (DRUC) Commitment Monthly Summary	*Yes*	• Capacity committed by the DRUC process indicates the level of out of market activity needed Day-Ahead to maintain reliability • This month, no resources were committed for either transmission or capacity

Operational Dashboard – February 2012

Metric	Trending as Expected	Further Information
Hourly Reliability Unit Commitment (HRUC) Monthly Summary	*Yes*	• Capacity committed by the HRUC process indicates the level of out of market activity needed during the Operating Day to maintain reliability • This month, no resources were committed for either transmission or capacity
Supplemental Ancillary Service Market Monthly Summary	*Yes*	• Normal trend indicates that deliverability was not a major concern
Non-Spinning Reserve Service Deployment	*Yes*	• Offline Non-Spin was not deployed this month
Congestion Revenue Rights Price Convergence	*Yes*	• Normal trend indicates good ability of market participants to estimate value of hedges

Operational Dashboard – March 2012

Metric	Trending as Expected	Further Information
Hourly Reliability Unit Commitment (HRUC) Monthly Summary	*Yes*	• Capacity committed by the HRUC process indicates the level of out of market activity needed during the Operating Day to maintain reliability • This month, two resources were committed for voltage support
Supplemental Ancillary Service Market Monthly Summary	*Yes*	• Normal trend indicates that deliverability was not a major concern
Non-Spinning Reserve Service Deployment	*Yes*	• Offline Non-Spin was deployed on 2 days for capacity and 3 days for voltage support
Congestion Revenue Rights Price Convergence	*Yes*	• Normal trend indicates good ability of market participants to estimate value of hedges

Operational Dashboard – February 2012

Metric	Trending as Expected	Further Information
Retail Transactions	*Yes*	• Seasonal variations in transaction volumes trending as expected
Advanced Metering	*Yes*	• 82.7% of ERCOT load settled with 15-minute interval data. • 4.6M Advanced Metering System (AMS) Electric Service Identifier (ESIID)s included in settlement
Settlement Dollars	*Yes*	• Normal trend of daily average settlement is less than $10M
Revenue Neutrality	*Yes*	• Normal trend of Revenue Neutrality is within +/- $5M
Market-Based Uplift to Load	*Yes*	• Normal trend of Net uplift to load is within +/- $10M

Operational Dashboard – March 2012

Metric	Trending as Expected	Further Information
Retail Transactions	*Yes*	• Seasonal variations in transaction volumes trending as expected
Advanced Metering	*Yes*	• 84% of ERCOT load settled with 15-minute interval data. • 4.8M Advanced Metering System (AMS) Electric Service Identifier (ESIID)s included in settlement • *Values reflective of March 1 – March 22; for full month detail refer to the appendix*
Settlement Dollars	*Yes*	• The daily average settlement is expected to be less than $10M
Revenue Neutrality	***No***	• As of Operating Day March 24th, Revenue Neutrality uplift is trending towards $7M, which is higher than the expected range of +/- $5M. Price separations caused by high wind in the first half of the month and outages during the month resulted in significant Point-to-Point obligation payouts. • *For full month detail refer to the appendix.*
Market-Based Uplift to Load	*Yes*	• No anomalies observed to-date • *For full month detail refer to the appendix.*

Market Enhancements Under Consideration

Enhancement	Further Information

Evaluating market design improvement proposals	• Increasing Power Balance penalty cost to \$4500
	• Offer Regulation / Responsive / Reliability Unit Commitments (RUC) / Reliability Must Run (RMR) Resource capacity at \$4500
	• NPRR444 to address
	  - 0 to LSL of RUC, RMR, Non-Spin and Quick Starts
	  - EILS deployments
	  - Load Resource deployments

Evaluating Pilot Project Feasibility	• Fast response regulation service • 30 min EILS service • Active deployment of Load Resources participating in Non-Spin based on forecasted price
Demand Response	• NPRR 451 at TAC to address Rule 25.507
Look-Ahead SCED	• NPRR351 - Phase I of Implementation (indicative future prices and ramping) is scheduled to be implemented by this summer • Working with Market Participants to draft scope for future stages of Look Ahead SCED

Major Project Highlights

Project	Trending as Expected	Further Information
NPRR351 Look-Ahead SCED Indicative Pricing - Provides future advisory/indicative pricing and ramping	*Yes*	Project on track for release in late June.
NPRR379 - EILS Dispatch Sequence & Performance Criteria Upgrades	*Yes*	Delay in completing overall requirements; however, requirements have been simplified with development to begin in early April. Aggressive project schedule with the goal of June for production release.
SCR760 - Recommended Changes Needed for Information Model Manager and Topology Processor for Planning Models	*Yes*	Potential risks of poor quality software that is delivered late and the vendor's ability to add more resources to meet agreed upon schedule. There are regular meetings with the project vendor and ERCOT project teams to review quality and schedule.
Texas Set 4.0 – Implement NPRR294, NPRR403, PUCT Project 34610, RMGRR100, Subst R 25.126	*Yes*	Project on track for June 3rd release date. Any scope changes during integration or market testing could impact delivery date and/or budget.
SCR 756 MarkeTrak Enhancements – Add functionality to the MarkeTrak Issue Resolution Tool	*Yes*	Project on track for June 1 release. Any scope changes during integration or market testing could impact delivery date and/or budget.
NPRR347/400 – Combines the DAM and the Real-Time Market Invoices into a single daily Settlement Invoice; Eliminate Unsecured Credit for CRR Auctions and for Future Credit Exposure (FCE); Eliminate netting of FCE with Current Credit Exposure (CCE)	*Yes*	Iterative project approach will be applied by continuing to define reports and execute on core system changes. Extensive hours for several key resources could delay completion due to competing priorities.
Settlement System Re-Write – Replace proprietary code, data structures and tools with an ERCOT supported solution	*Yes*	Potential risks include new NPRR cross system impacts, loss of SME resources, and software performance

Projects with Red or Yellow Status

Project	Trending as Expected	Further Information
Security Project #3 - Security solution delivery	No, issue with budget and schedule	Assumptions for time needed to build requirements and architecture were inaccurate. Extended planning to ensure requirements and design are well understood
Resource Asset Registration Form Upgrade (RARF) - Increase the data collected for Wind resources and add new resource type data	No, issue with budget and schedule	Changes to RARF were needed in support of NPRR 437. Loss of critical business resource has resulted in staff re-learning the backend procedures.
Security Project #2 - Security solution delivery	No, issue with budget	Planned work did not occur in 2011. Ensure scheduled labor hours are sufficient to meet project tasks and timelines
NPRR361 - New public 5 minute report for wind production and changes the existing hourly Actual and Forecast Regional Wind Report	No, issue with budget	Change in design approach during execution. Original assumptions of design approach were not realized in the execution phase of the project.

The *ERCOT Monthly Operational Overview* will be posted to (http://www.ercot.com/committees/board/) on the 15th day of the following month