Item 8.3: Operations Report
(November and December 2013)

Trip Doggett
President & CEO

Board of Directors Meeting
ERCOT Public
February 11, 2014

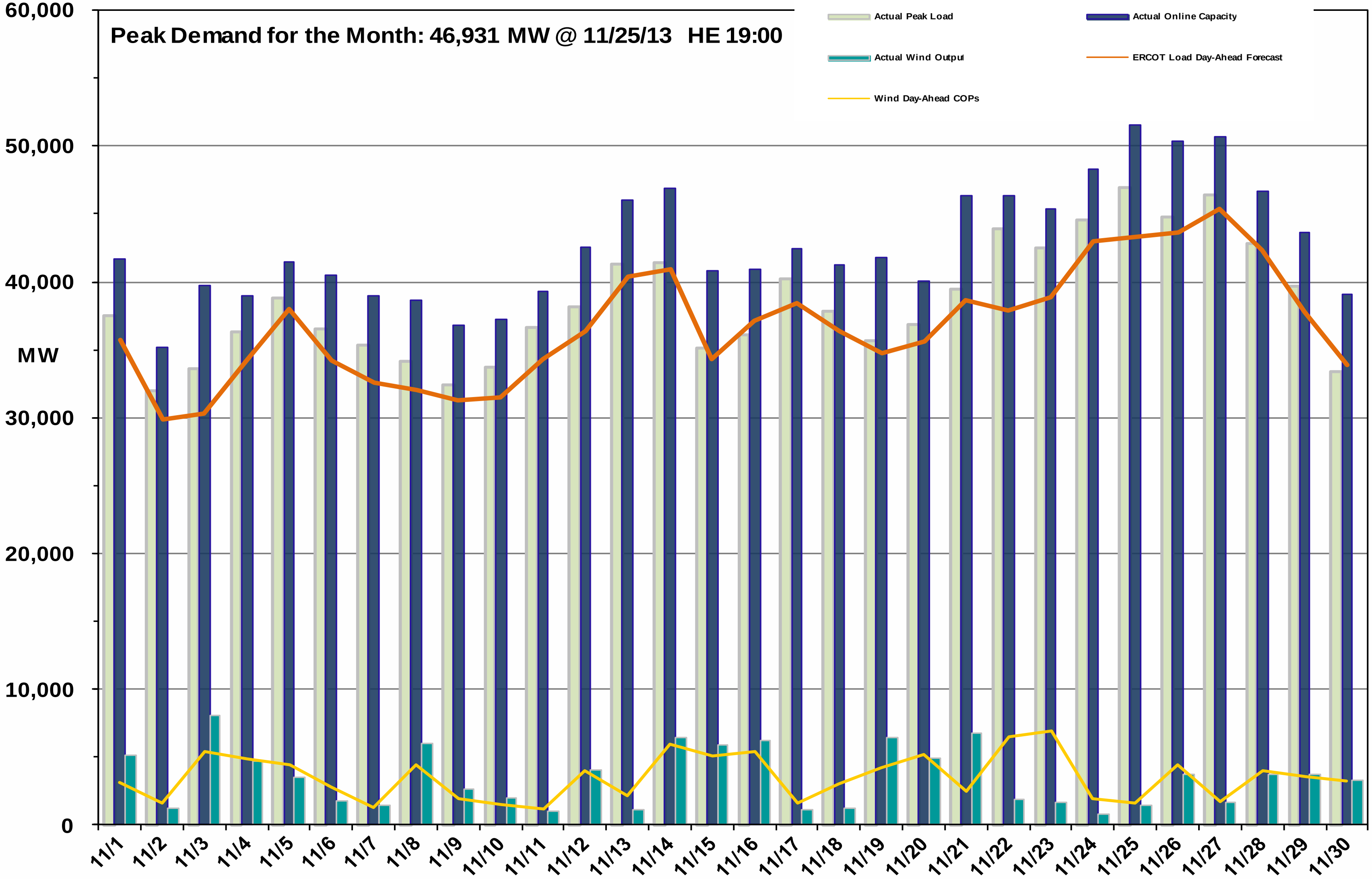
Summary – November 2013

- **Operations**
  - The peak demand of 46,931 MW on November 25th was more than the mid-term forecast peak of 43,287 MW as well as the November 2012 actual peak demand of 41,626 MW. The instantaneous load on November 25th was 47,030 MW.
  - Day-ahead load forecast error for November was 3.48%
  - ERCOT issued
    - One Operating Condition Notice (OCN) for unplanned outages in the West.
    - Three advisories for Physical Responsive Capability (PRC) below 3000 MW.
  - No Watches were issued
  - No Emergency Notices were issued
  - No Energy Emergency Alert (EEA) events
- **Planning Activities**
  - 194 active generation interconnection requests totaling over 50,000 MW, including 22,600 MW of wind generation as of November 30, 2013. Twelve more requests and 2,900 more MW from October 31, 2013.
  - 10,970 MW wind capacity in commercial operation November 30, 2013; no change from October 31, 2013.

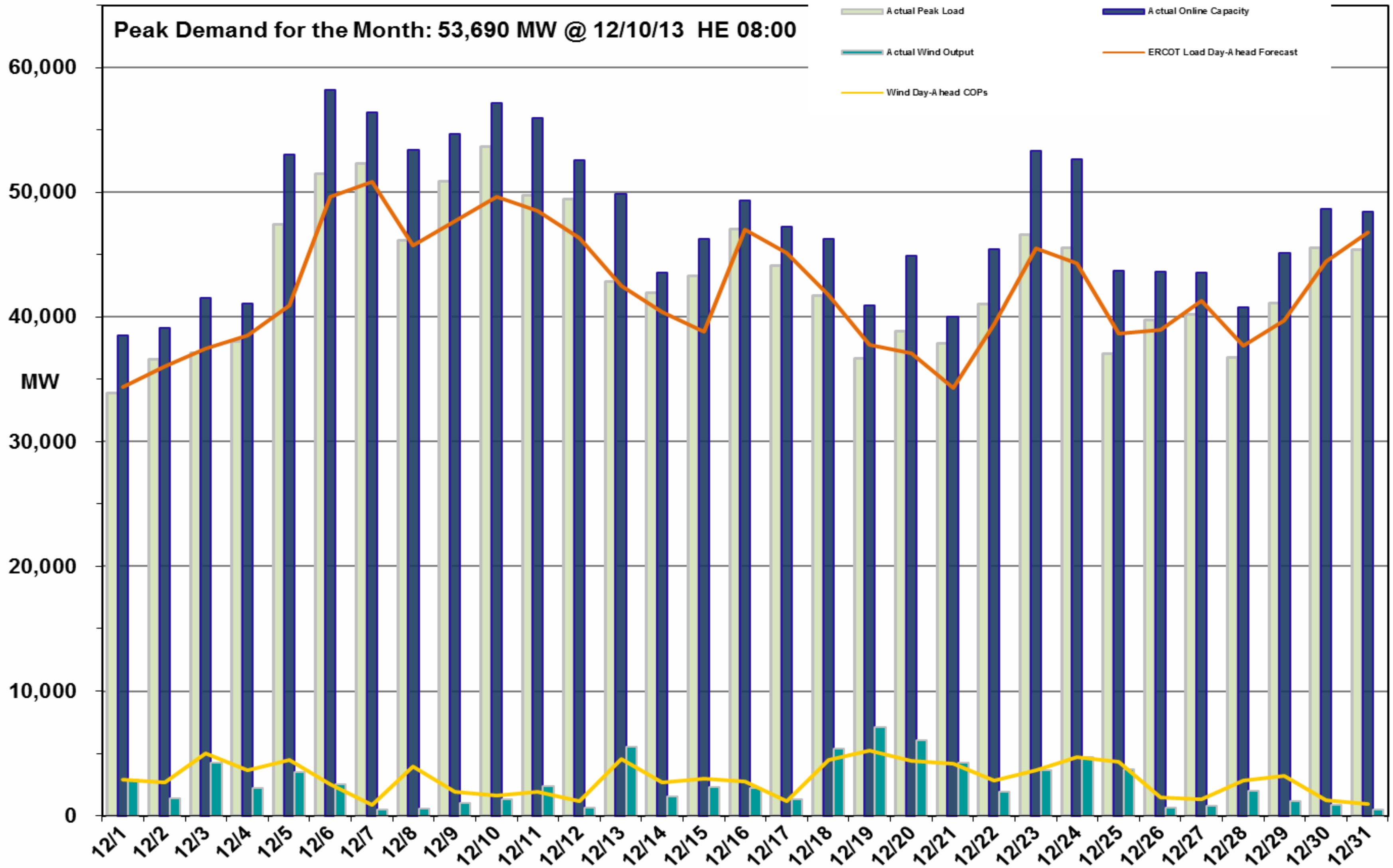
Summary – December 2013

- **Operations**
  - The peak demand of 53,690 MW on December 10th was more than the mid-term forecast peak of 49,673 MW as well as the December 2012 actual peak demand of 45,545 MW. The instantaneous load on December 10th was 54,326 MW.
  - Day-ahead load forecast error for November was 3.37%
  - ERCOT issued two advisories for Voltage Security Assessment Tool (VSAT) not solving for 30 minutes.
  - No Watches were issued
  - No Emergency Notices were issued
  - No Energy Emergency Alert (EEA) events
- **Planning Activities**
  - 205 active generation interconnection requests totaling over 51,100 MW, including 24,200 MW of wind generation as of December 31, 2013. Eleven more requests and 1,600 more MW from November 30, 2013.
  - 11,255 MW wind capacity in commercial operation December 31, 2013; 285 more MW than November 30, 2013.

Daily Peak Demand: Hourly Average Actual vs. Forecast, Wind Day-Ahead COPs & On-line Capacity at Peak – Nov. 2013



Daily Peak Demand: Hourly Average Actual vs. Forecast, Wind Day-Ahead COPs & On-line Capacity at Peak – Dec. 2013



Market Statistics – November 2013

Market Statistics	November 2012	November 2013	2012 Average	2013 YTD Average
Percentage of Real-Time load hedged in Day-Ahead Market	128.66%	129.87%	122.66%	120.45%
Average 'ERCOT Hub Average 345 kV Hub' Settlement Point Price in Day-Ahead Market ($/MWh)	29.82	31.55	30.18	33.91
Average 'ERCOT Hub Average 345 kV Hub' Settlement Point Price in Real-Time ($/MWh)	27.30	31.24	26.49	32.35

Market Statistics – December 2013

Market Statistics	December 2012	December 2013	2012 Average	2013 YTD Average
Percentage of Real-Time load hedged in Day-Ahead Market	121.71%	129.14%	122.66%	121.18%
Average 'ERCOT Hub Average 345 kV Hub' Settlement Point Price in Day-Ahead Market ($/MWh)	26.30	36.57	30.18	34.14
Average 'ERCOT Hub Average 345 kV Hub' Settlement Point Price in Real-Time ($/MWh)	24.69	33.52	26.49	32.45

Operational Performance Measures – November 2013

Performance Measure	Target Met	Further Information
Retail Transaction Performance *(Target 98%)*	*Yes*	• Retail transaction processing performance was at 100%
Settlements Performance *(Target 99%)*	*Yes*	• 100% timely statement and invoice posting

Operational Performance Measures – December 2013

Performance Measure	Target Met	Further Information
Retail Transaction Performance *(Target 98%)*	*Yes*	• Retail transaction processing performance was at 100%
Settlements Performance *(Target 99%)*	*Yes*	• 100% timely statement and invoice posting

Operational Dashboard – November 2013

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 • No resources were committed in DRUC in this period

Operational Dashboard – December 2013

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 • 1 resource was committed in DRUC in this period

Operational Dashboard – November 2013

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 • Seven resources were committed in November to help resolve congestion or voltage stability
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 during this period
Congestion Revenue Rights Price Convergence	*Yes*	• Normal trend indicates good ability of market participants to estimate value of hedges

Operational Dashboard – December 2013

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 • Four resources were committed in December to help resolve congestion, system reliability or voltage stability
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 during this period
Congestion Revenue Rights Price Convergence	*Yes*	• Normal trend indicates good ability of market participants to estimate value of hedges

Operational Dashboard – November 2013

Metric	Trending as Expected	Further Information
Retail Transactions	*Yes*	• Seasonal variations in transaction volumes trending as expected
Advanced Metering	*Yes*	• 97.8 % of ERCOT load settled with 15-minute interval data. • 6.4M Advanced Metering System (AMS) Electric Service Identifier (ESIID)s included in settlement as of November 2013.
Settlement Dollars	*Yes*	• As of settlement of Operating Day 11/30/2013, the daily average settlement dollars are $11.4M, which is down from $13.1M in October 2013 and higher than November 2012 which had an average of $9.0M.
Revenue Neutrality	*Yes*	• As of settlement of Operating Day 11/30/2013, Revenue Neutrality uplift is a credit of $0.19M, which is down from October 2013 which was a charge of $3.68M and down from November 2012 which was a charge of $2.48M.
Market-Based Uplift to Load	*Yes*	• As of settlement of Operating Day 11/30/2013, the market-based uplift to load is a charge of $3.34M, as opposed to a $4.21M charge in October 2013 and a charge of $4.18M in November 2012.

Operational Dashboard – December 2013

Metric	Trending as Expected	Further Information
Retail Transactions	*Yes*	• Seasonal variations in transaction volumes trending as expected
Advanced Metering	*Yes*	• 98.0 % of ERCOT load settled with 15-minute interval data. • 6.5M Advanced Metering System (AMS) Electric Service Identifier (ESIID)s included in settlement as of December 2013.
Settlement Dollars	*Yes*	• As of settlement of Operating Day 12/31/2013, the daily average settlement dollars are $11.8M, which is up slightly from $11.4M in November 2013 and higher than December 2012 which had an average of $7.9M.
Revenue Neutrality	*Yes*	• As of settlement of Operating Day 12/31/2013, Revenue Neutrality uplift is a charge of $1.73M, which is up from November 2013 which was a credit of $0.19M and down from December 2012 which was a charge of $0.81M.
Market-Based Uplift to Load	*Yes*	• As of settlement of Operating Day 12/31/2013, the market-based uplift was a charge of $6.11M, as opposed to a $3.34M charge in November 2013 and a credit of $5.59M in December 2012.

Market Enhancements Under Consideration

Enhancement	Further Information
Evaluating market design improvement proposals	• ERCOT BOD approved NPRR 568 and corresponding Other Binding Document (OBD) on 11/19/2013 • ERCOT has completed the Planning Phase of Implementing the NPRR and is now working on the Development Phase of the Implementation • Go live date is still 6/1/2014 • Update given to TAC on 1/28/2014 on Implementation Status
Evaluating Pilot Project Feasibility	• Fast Responding Regulation Service pilot started on Operating Day 2/25/13 and will continue until 2/28/14 • 30-minute ERS pilot will continue through end of January 2014. NPRR564 putting 30-Minute ERS into the protocols was approved during the November 2013 Board meeting effective on February 1, 2014. • Weather-Sensitive ERS pilot project concluded at the end of September 2013. NPRR571 was approved during the December 2013 Board meeting putting the requirements to participate as a weather sensitive load into the protocols with an effective date of June 1, 2014.

Major Project Highlights (as of 1/30/2014)

Project	Trending as Expected	Further Information
EMS Upgrade – Upgrade EMS and OTS from ALSTOM EMP 2.3 to EMP 3.0	*Yes*	• The project is tracking to approved schedule and budget baselines • Planning Phase 2 – the team is currently working on the Technical Architecture documentation, as well as development of new/updated test scripts. Key milestones completed so far are: ○ Delivery and approval of all Functional Requirements ○ Delivery and approval of all Functional Design documents ○ Evaluation of the base ALSTOM product to determine mitigation options for ERCOT customs ○ Completion of system planning activities to identify environment impacts • Early Risk Mitigation – this work, which involves development of a subset of key application subsystems, was started in December 2013 by both ERCOT and ALSTOM and continues on track with no major issues.
2014 Market Enhancements – delivery of several Market related NPRRs including NPRR568, Real-Time Reserve Price Adder Based on Operating Reserve Demand Curve and NPRR555, Load Resource Participation in Security-Constrained Economic Dispatch	*Yes*	• Project in Execution phase and tracking to approved schedule and budget • Code development, test documentation and training plans underway for the following scope components: ○ NPRR568 – Real-Time Reserve Price Adder Based on Operating Reserve Demand Curve; ○ NPRR564 – Thirty-Minute Emergency Response Service (ERS); ○ NPRR555 – Load Resource Participation in Security-Constrained Economic Dispatch; ○ NPRR532 – Performance Measurement and Verification and Telemetry Requirements for Load Resources Providing Non-Spin; ○ NPRR240 – Proxy Energy Offer Curve; and ○ Other Binding Document (OBD) for Setting the Shadow Price Caps and Power Balance Penalties in Security Constrained Economic Dispatch. • Production changes will occur in three releases: ○ February 2014 – NPRR240 (code is currently being tested); ○ April 2014 - NPRR564; and ○ June 1, 2014 – remainder of enhancements (NPRR568, NPRR555, NPRR532 and the OBD).
Oracle 11g Upgrade – Upgrade Oracle databases and related tools that support ERCOT's application portfolio from Oracle 10g to Oracle 11g	*Yes*	• Vendor software bugs reported last month have been resolved but project schedule and budget were impacted • Approved a change request in December to extend schedule by six weeks and increase budget by 5%. ○ A stability issue in the Information Services Master (ISM) database has been resolved and the environment remains stable since the fix was applied. ○ ERCOT is also still addressing a performance degradation seen in the Commercial System Integration (CSI) application. A fix is expected to be tested in early February. • Remaining upgrades for EMS, CRR, Nodal TIBCO, CMM, and MIS have been started in the lower development environments or vendor environments.

Major Project Highlights (cont.) (as of 1/30/2014)

Project	Trending as Expected	Further Information
ABB MMS/OS Technology Refresh - improve ERCOT's ability to support and maintain the Market Management System (MMS) and Outage Scheduler (OS) system by upgrading the underlying infrastructure and its required components to versions on mainstream vendor support	***No***	• Planning phase began in late May 2013 with a target to complete in November 2013; however, this milestone has been delayed. • Factors contributing to delay: ○ Hardware vendor contract negotiations took longer than expected which pushed subsequent Planning activities out. ○ Analysis of cross-project impacts from other high priority projects (2014 Market Enhancements and EMS Upgrade) required effort that was not accounted for in the original Planning schedule. • To mitigate the schedule impact, the team has proactively re-planned remaining work • A change control to extend Planning will be presented for executive approval on February 5.
Settlement System Upgrade – Replace proprietary code, data structures and tools with an ERCOT supported solution	*Yes*	• Project continues to track to the planned Q4 2014 go-live • Code development complete for 53% of required components (up from 37% reported in November 2013) • Functional Acceptance Testing (FAT) completion is at 47% (up from 28%). • Budget may increase to extend contract developers by 6 months to minimize overall risk to the project and ensure adequate knowledge transfer to ERCOT staff. • Completed evaluation of potential impacts resulting from the Market Enhancements project (NPRR568/NPRR555) and determined no change to schedule or budget needed.

Appendix

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