



**Project No. 49852, Review of Summer 2019
ERCOT Market Performance**

ERCOT's Review of Summer 2019

ERCOT Public
October 11, 2019

Key Observations for Summer 2019

- Early summer was mild, and August was very hot (September was also above normal).
- There were many days with tight conditions, and an Energy Emergency Alert (EEA) Level 1 was declared twice.
 - Emergency Response Service (ERS) deployments prevented the need for EEA2.
- Peak demand day saw higher Intermittent Renewable Resource (IRR) production.
 - As a result, it was not one of the highest-priced days, and there was no EEA.
- Tightest conditions frequently occurred earlier than time of peak demand.
- Resource performance continues to outpace historical patterns.
- Overall, the market outcomes supported reliability needs.
- Even with significant pricing events, there were no mass transitions.

Outline

- Summer overall
- Peak week
- Peak day
- EEA days
- Commercial information

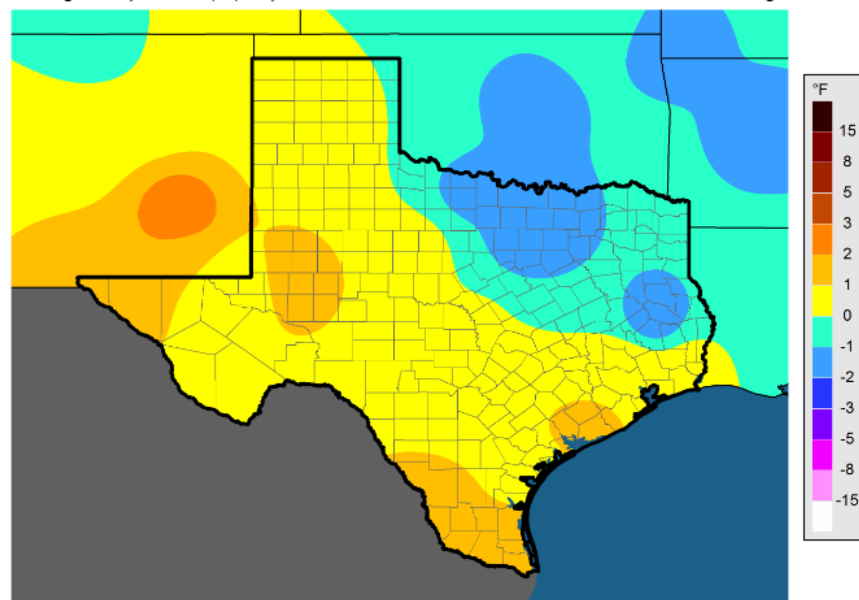
Summer Overall

Weather

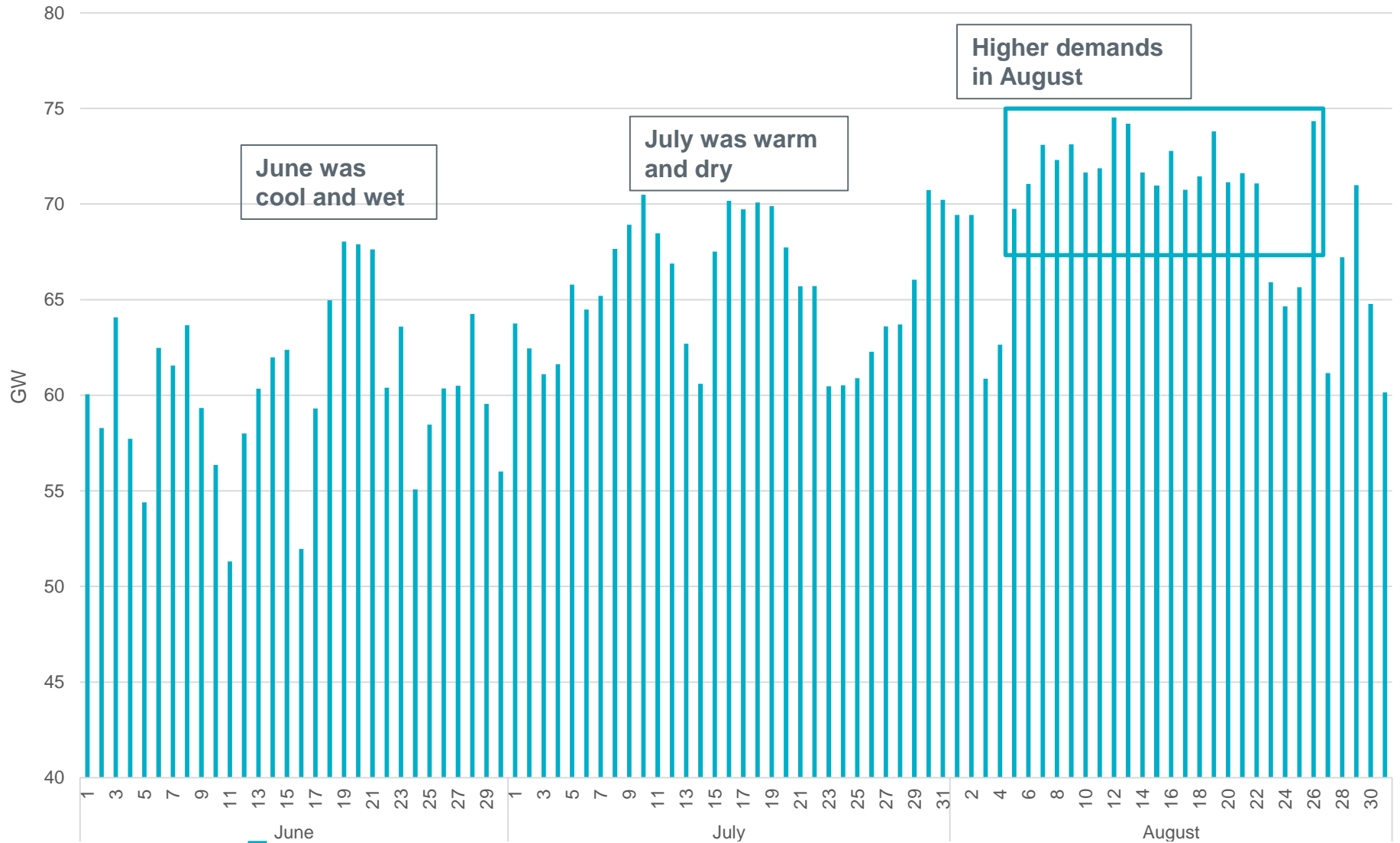
- June – July 2019 was the coolest since 2007*
- August 2019 was the 2nd hottest on record*
- Overall, June – August 2019 was 21st hottest on record
- Extended period of above normal heat in Texas – but not much extreme heat (105 or greater)
- Comparison to 2018 differed across the state
 - Dallas cooler
 - Austin/San Antonio similar
 - Houston, South Texas hotter
 - More heat along coast

*Based on mean temperature

Average Temperature (°F) Departure from 20190601 to 20190831 - Fifteen Year Average

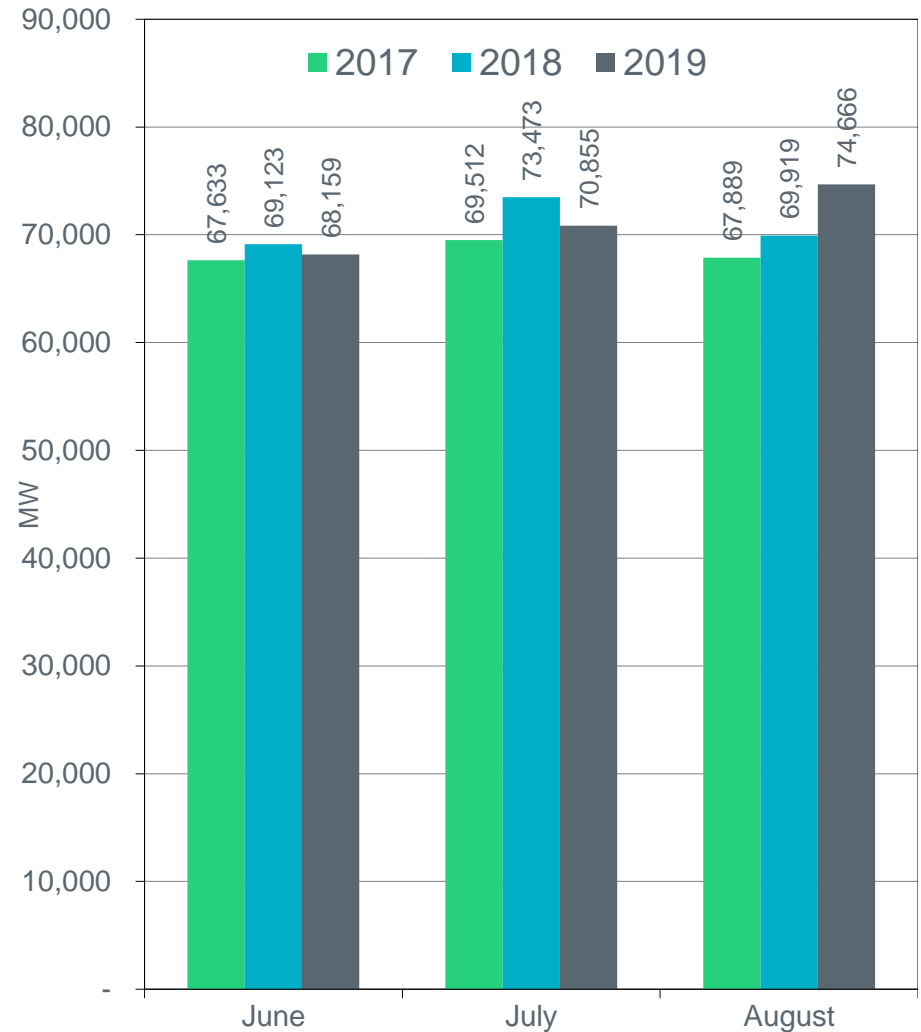


Daily Peak Hour Demands



Comparison of Summer Monthly Peak Demand

- A new all-time record for system demand peak was set at 74,666 MW on Aug. 12, 2019.
- A new all-time record for weekend system demand peak was set at 71,915 MW on Aug. 11, 2019.
- Monthly peak demands in June and July 2019 were lower than 2018.



* Data: Hourly integrated peak demand as published in the ERCOT D&E report.

Day-Ahead Load Forecast Performance

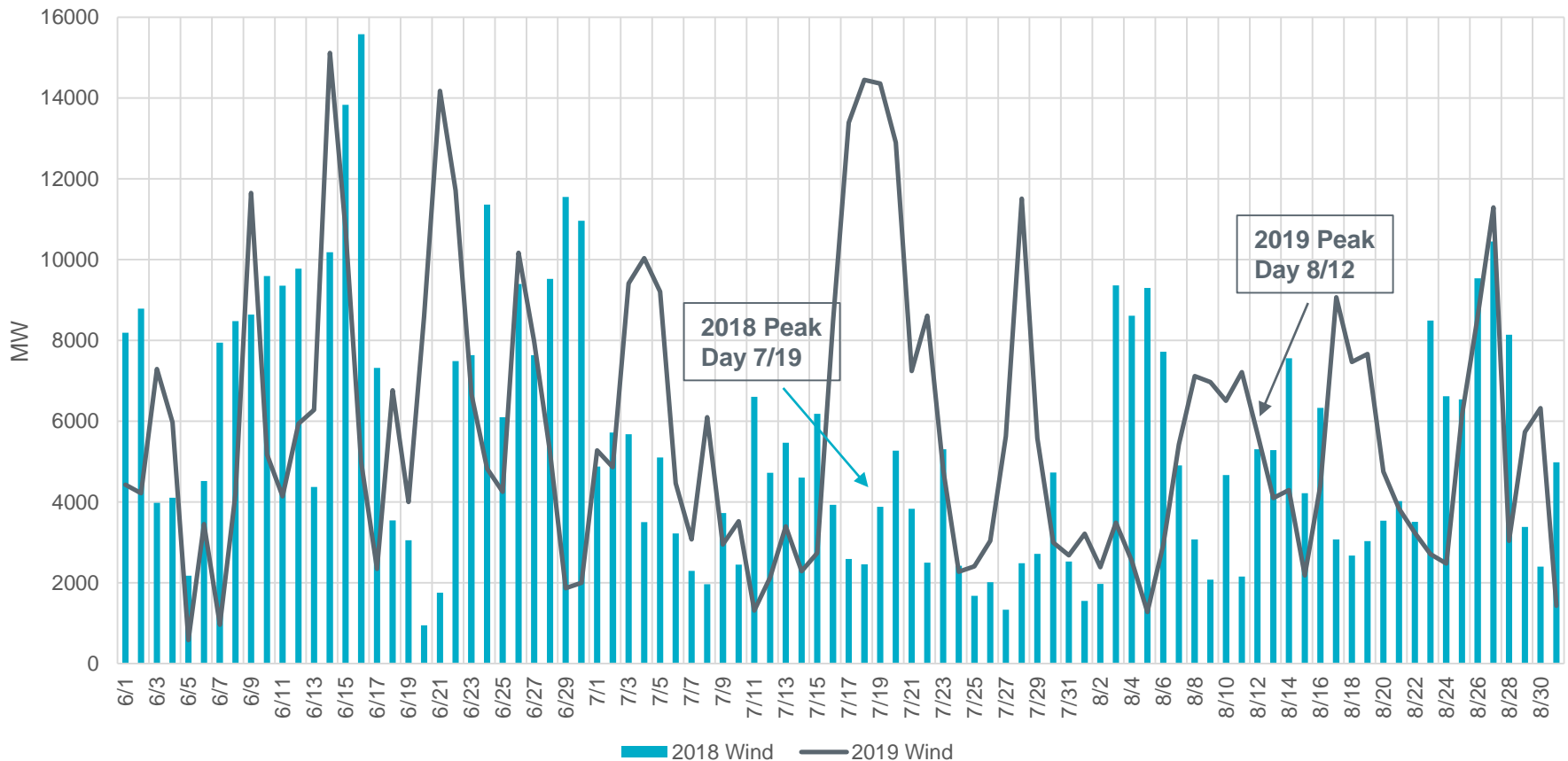
- Mean Absolute Percent Error (MAPE) for ERCOT Mid-Term Load Forecast (MTLF) at 14:00 Day-Ahead trended as normal on average.

	June	July	August	Average YTD MAPE 2019
Average Monthly MAPE	3.03	2.21	2.15	2.50
Lowest Daily MAPE in Month	0.95	0.64	0.40	
Highest Daily MAPE in Month	9.62	4.55	9.00	

Wind Output

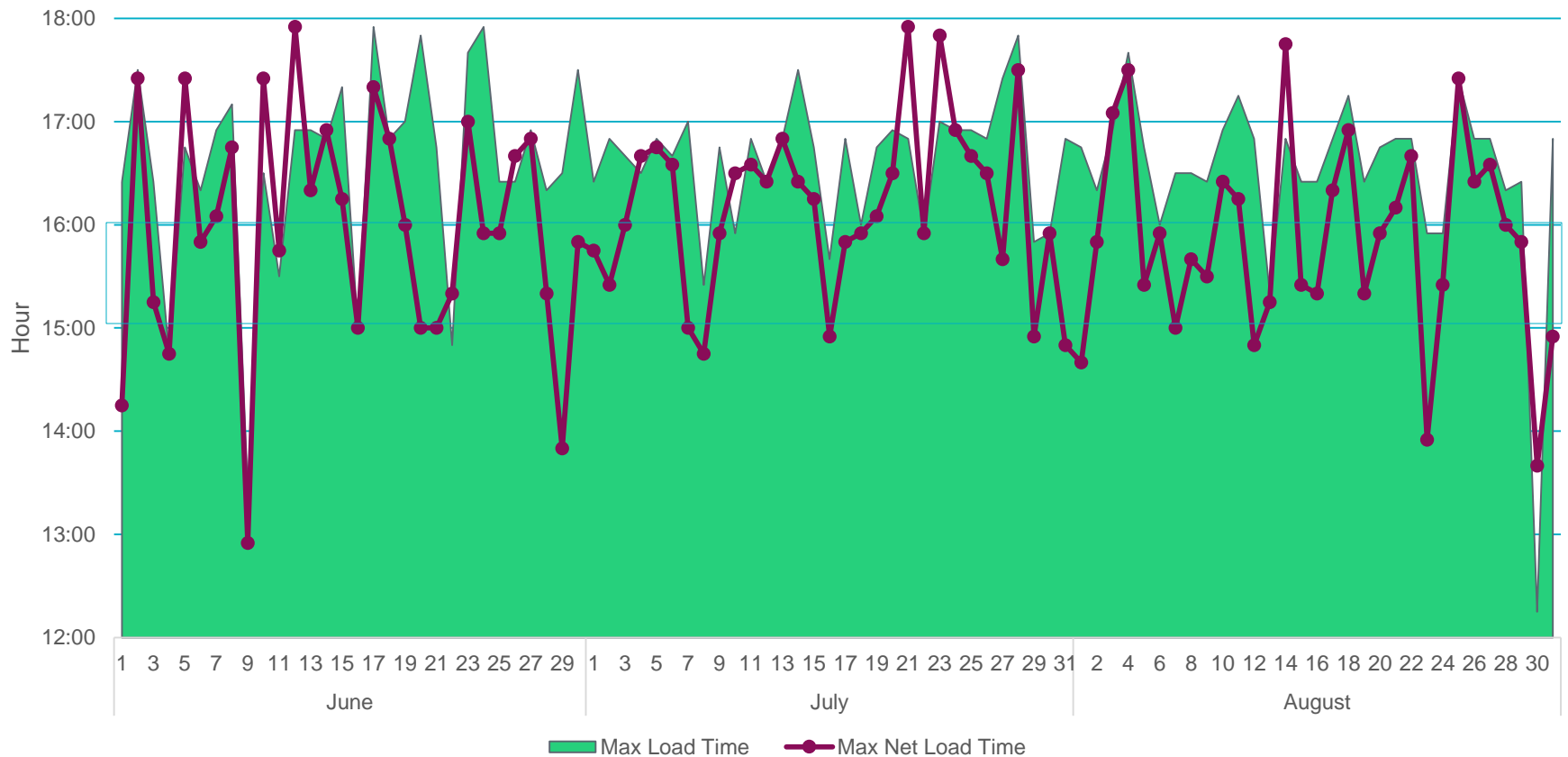
- ERCOT had approximately 2,400 MWs of additional installed wind capacity going into summer 2019 compared to 2018.

For hour ending 15:00



Timing of Peak Load and Peak Net Load (Load-IRR)

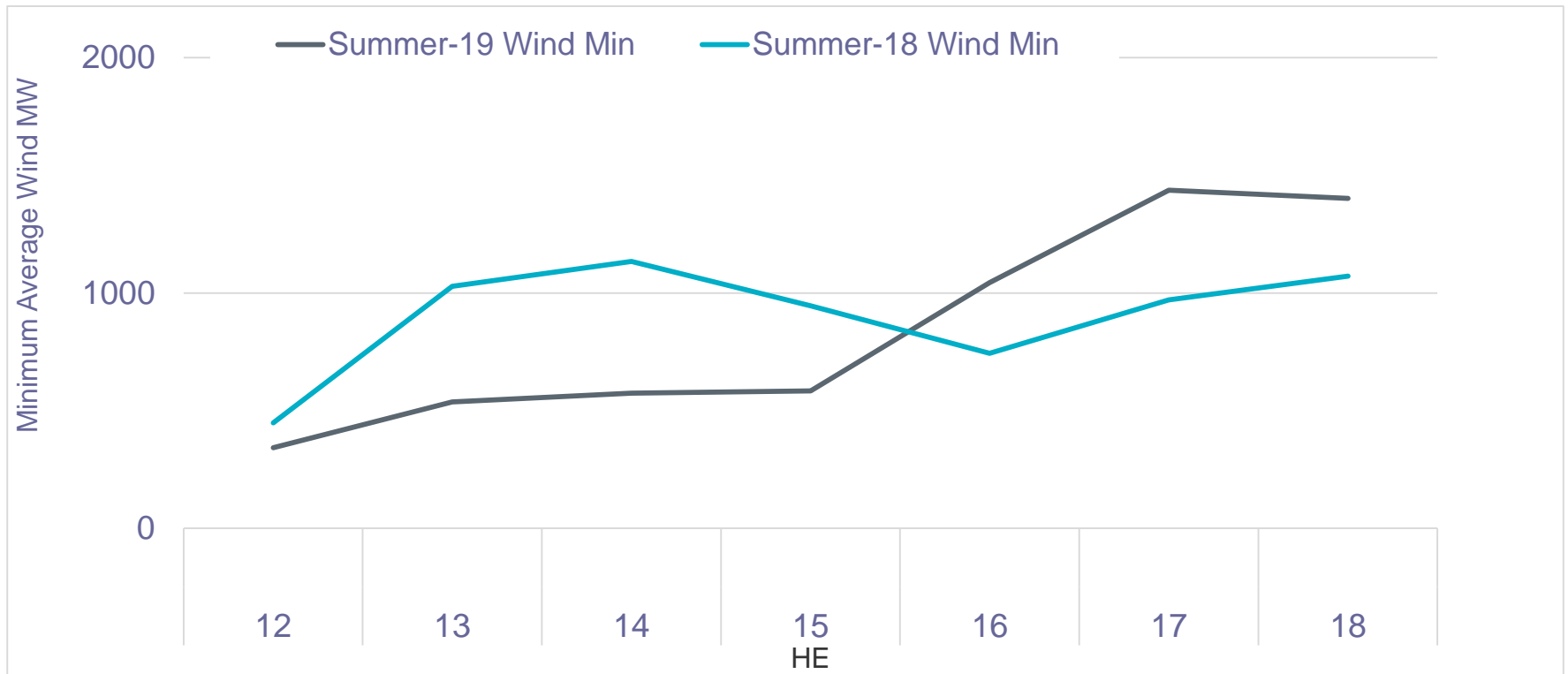
- During summer 2019, the peak net load frequently occurred prior to peak load.
- Net peak load occurred prior to 4 p.m. nearly 2/3 of the days in August.



Time is rounded to nearest 5-minute interval

Minimum Wind Generation for June – August

- Looking at the minimum wind each day for each hour and taking the average, the wind output was lower earlier in the afternoon and higher later in the afternoon when compared to 2018.



Day-Ahead IRR Forecast Performance

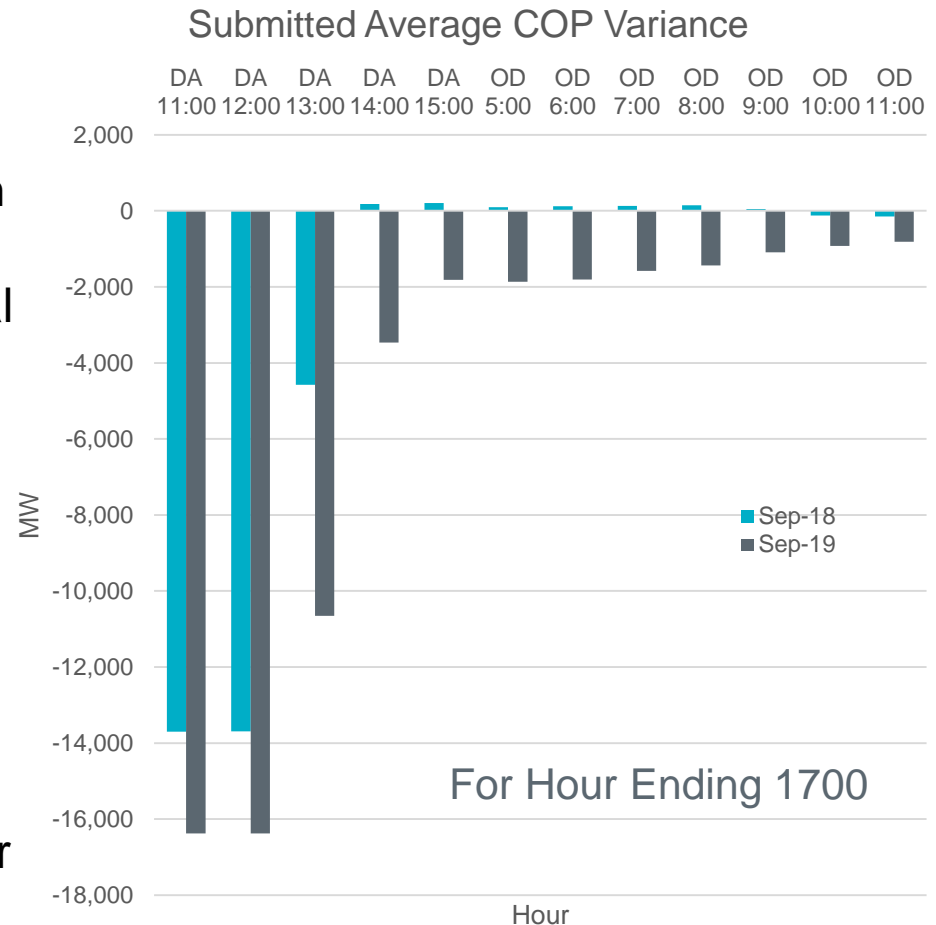
- Mean Absolute Percent Error (MAPE) for ERCOT wind and solar forecast at 14:30 Day-Ahead trended as normal on average.

	June	July	August	Average YTD 2019
Wind Average Monthly MAPE	4.1	4.1	4.7	4.9
Solar Average Monthly MAPE	6.38	4.94	4.79	6.98

*Solar calculations are for all hours where solar production is greater than 5 MW

COP Variance - September 2018 vs. 2019

- Current Operating Plan (COP) – “A plan by a QSE reflecting anticipated operating conditions for each of the Resources that it represents for each hour in the next seven Operating Days, including Resource operational data, Resource Status, and Ancillary Service Schedule.”
- COP variance shows the difference between predicted online MWs as reflected in the COPs and the actual online MWs for thermal generators.
- The COP variance during the Operating Day was higher in summer 2019, e.g., September.

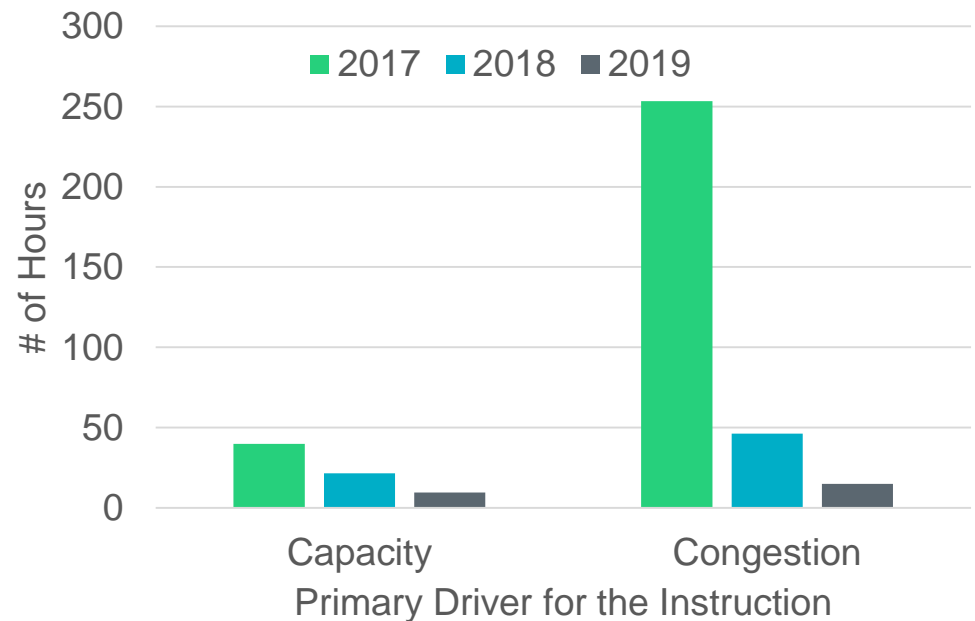


COP Variance = COP HSL – SCED HSL for online units and COP HSL – SCED MW for startup and shutdown units. SCED values are time-weighted for the delivery hour.

Number of RUC Instructions Continued to Decrease

- Noticeable trend toward self-commitment during peak periods.
- June instructions were all extensions of self-committed hours when the unit was needed for congestion.
- August instructions (occurred on two different days) were driven by capacity shortage and longer lead times.

2017 to 2019 Effective RUC
Resource-Hours
June through August

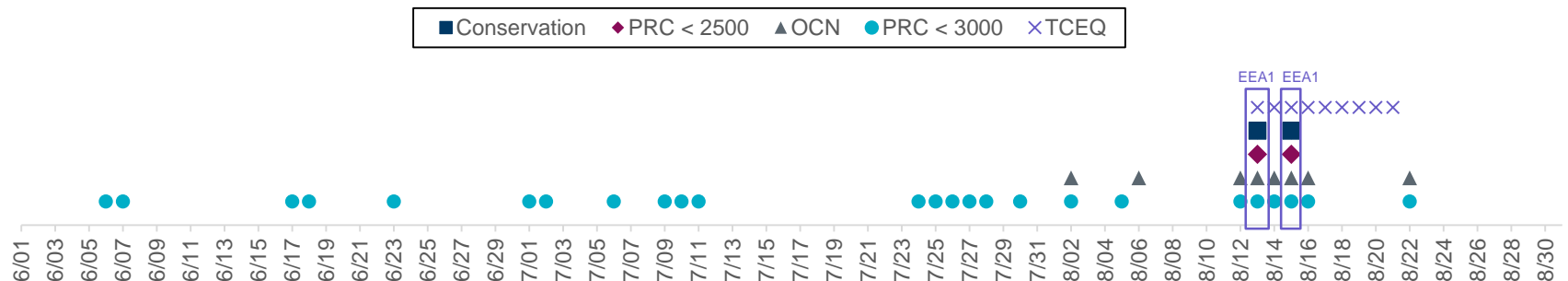


Note: this does not include VDIs

Operating Notices Issued in June – August 2019

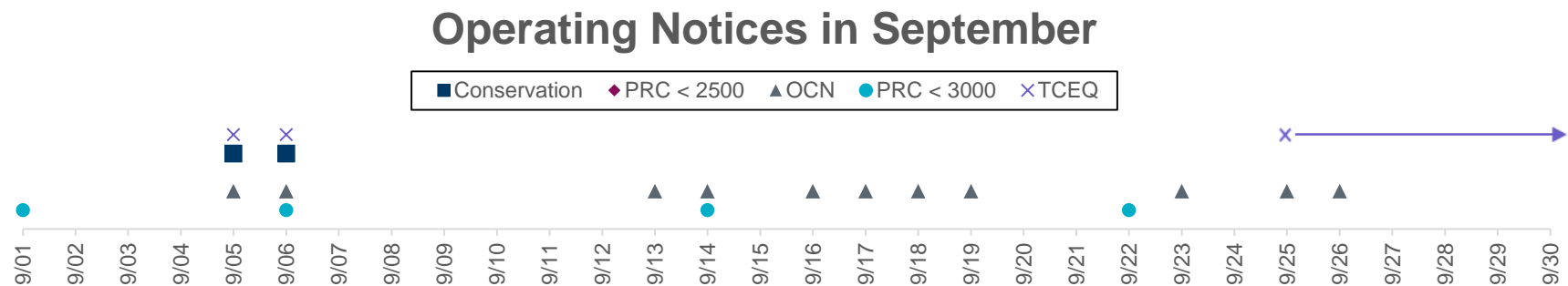
- 8 Operating Condition Notices (OCNs) for reserve capacity shortage
- 25 Advisories due to Physical Responsive Capability (PRC) less than 3,000 MW
- 2 Watches due to PRC less than 2,500 MW
- 2 EEA Level 1 events
- 2 conservation requests during August EEAs
- 1 TCEQ Notice of Enforcement Discretion
 - Effective for Operating Days 8/13-8/21

Operating Notices for June - August



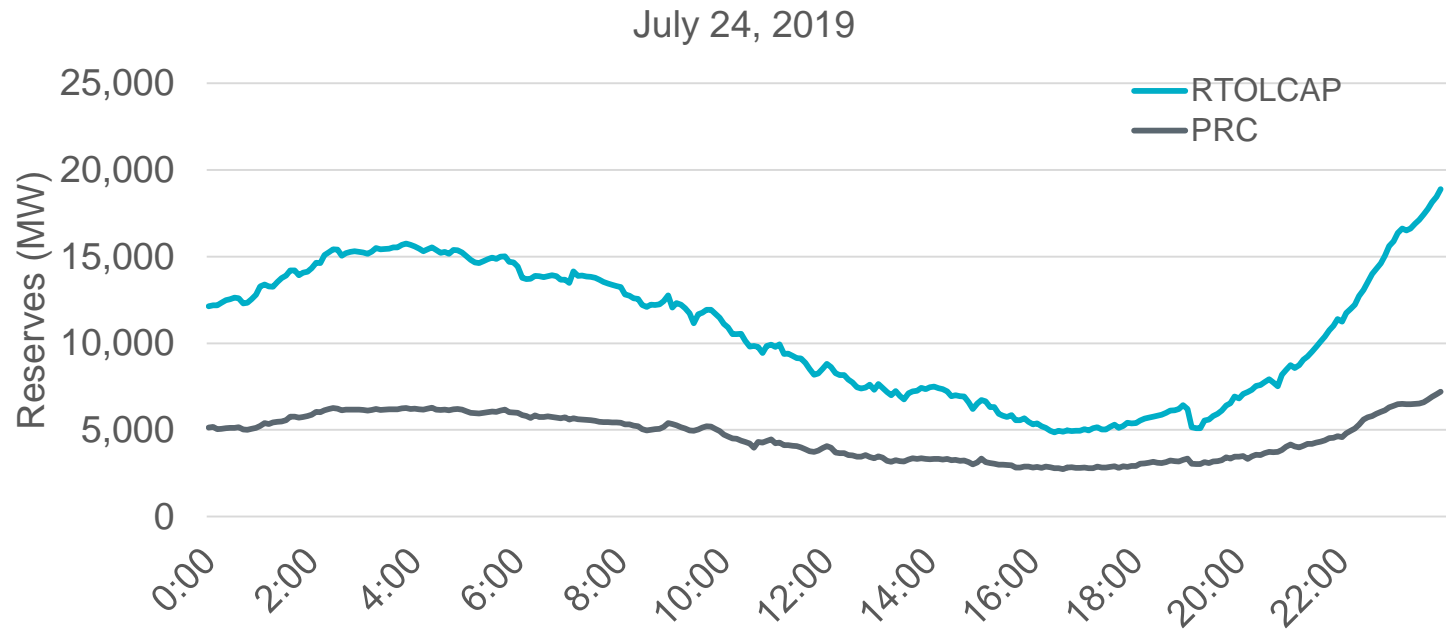
Operating Notices Issued in September 2019

- 11 OCNs for reserve capacity shortage
- 4 Advisories due to PRC less than 3,000 MW
- 1 voluntary conservation request for Operating Days 9/5 and 9/6
- 2 TCEQ Notices of Enforcement Discretion
 - 1 system-wide notice for Operating Days 9/5 and 9/6
 - 1 notice for Permian Basin units for Operating Days beginning 9/25



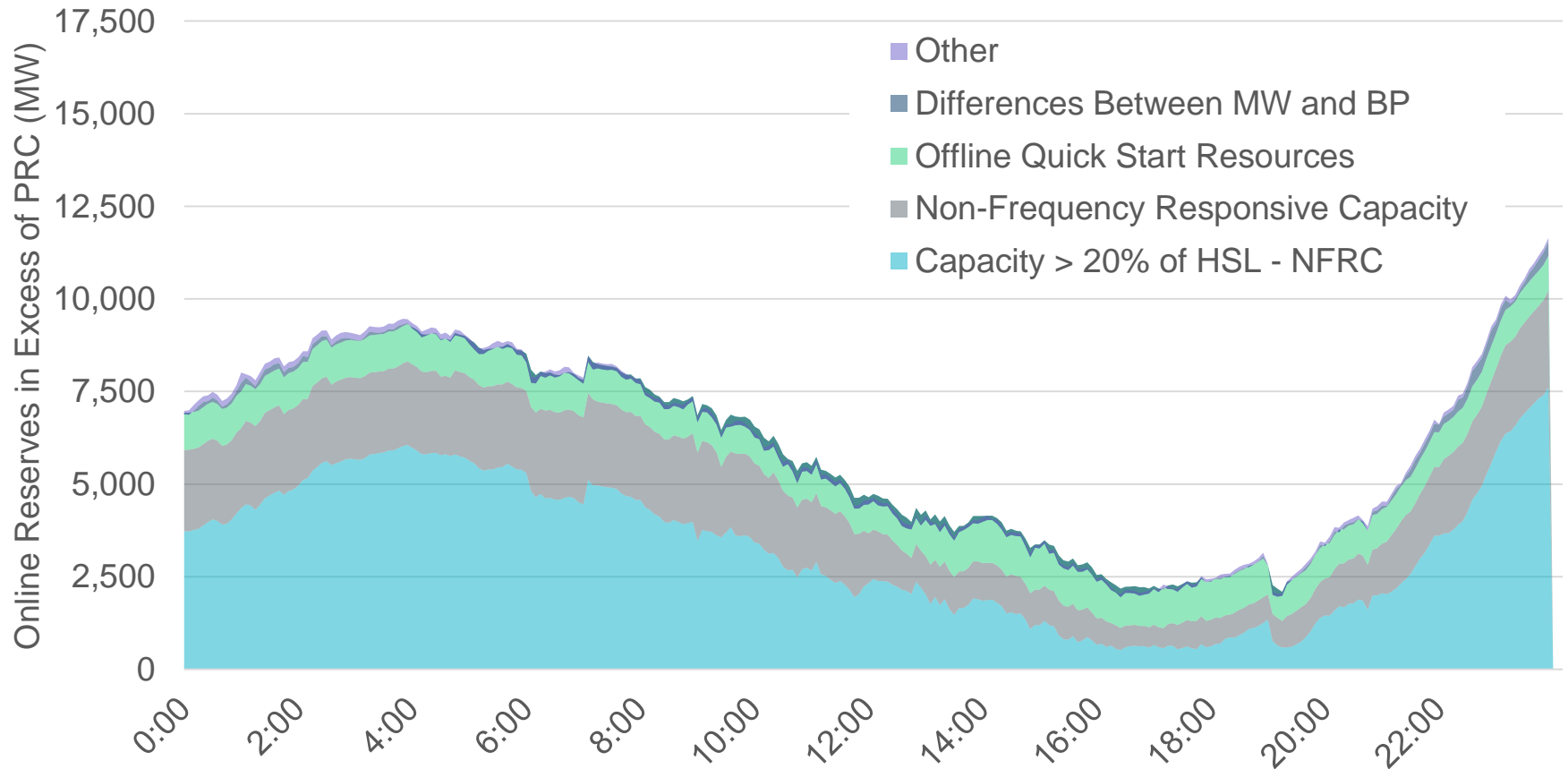
Advisory for PRC < 3,000 MW on July 24, 2019

- Advisories for PRC < 3,000 MW were issued on several days (e.g. July 24).
- On these days, while PRC was low, there was non-frequency responsive capacity (which does not contribute to PRC) and offline Quick Start Generating Resource (QSGR) capacity still available.



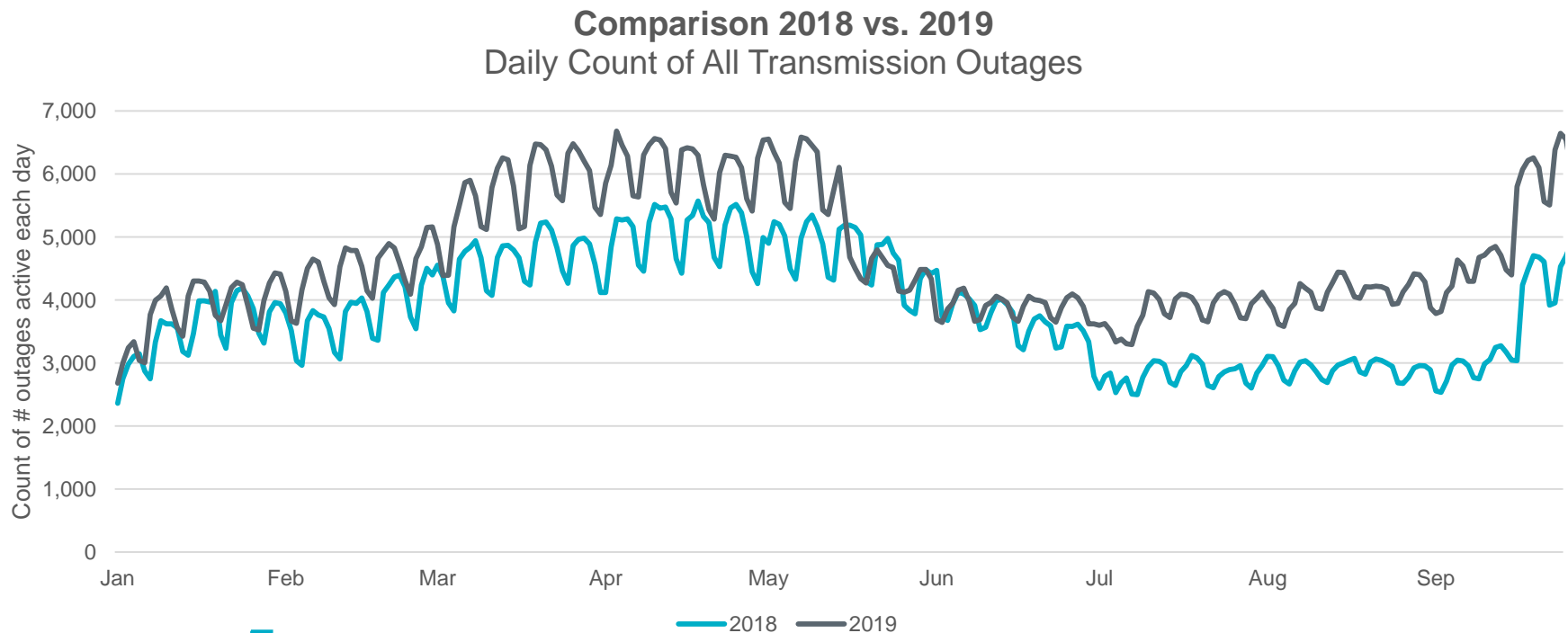
Online Reserves Above PRC Due to Unfired Combined Cycle Duct Capacity (NFRC) and Offline Quick Starts

Online Reserves in Excess of PRC - July 24, 2019



Planned Transmission Outages

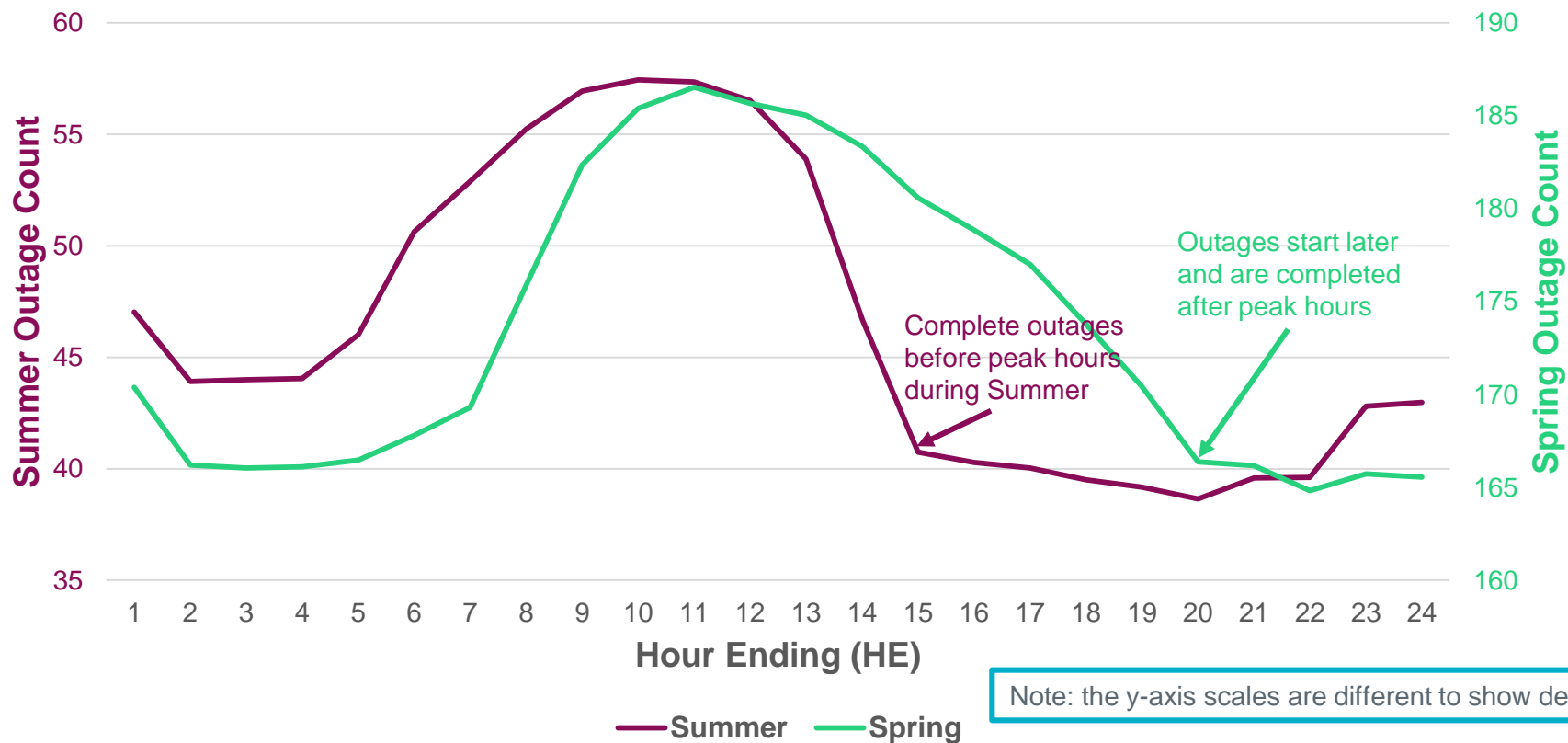
- Restrictions on summer transmission outages were again implemented to avoid planned transmission outages that could require generation curtailment during high load periods.
- With longer lead time to adjust outage plans to meet the restrictions compared to 2018, more maintenance and upgrade outages were approved, even during summer.



Transmission Outages in Summer 2019

- There are impacts of meeting these restrictions, such as starting outages very early in the day.

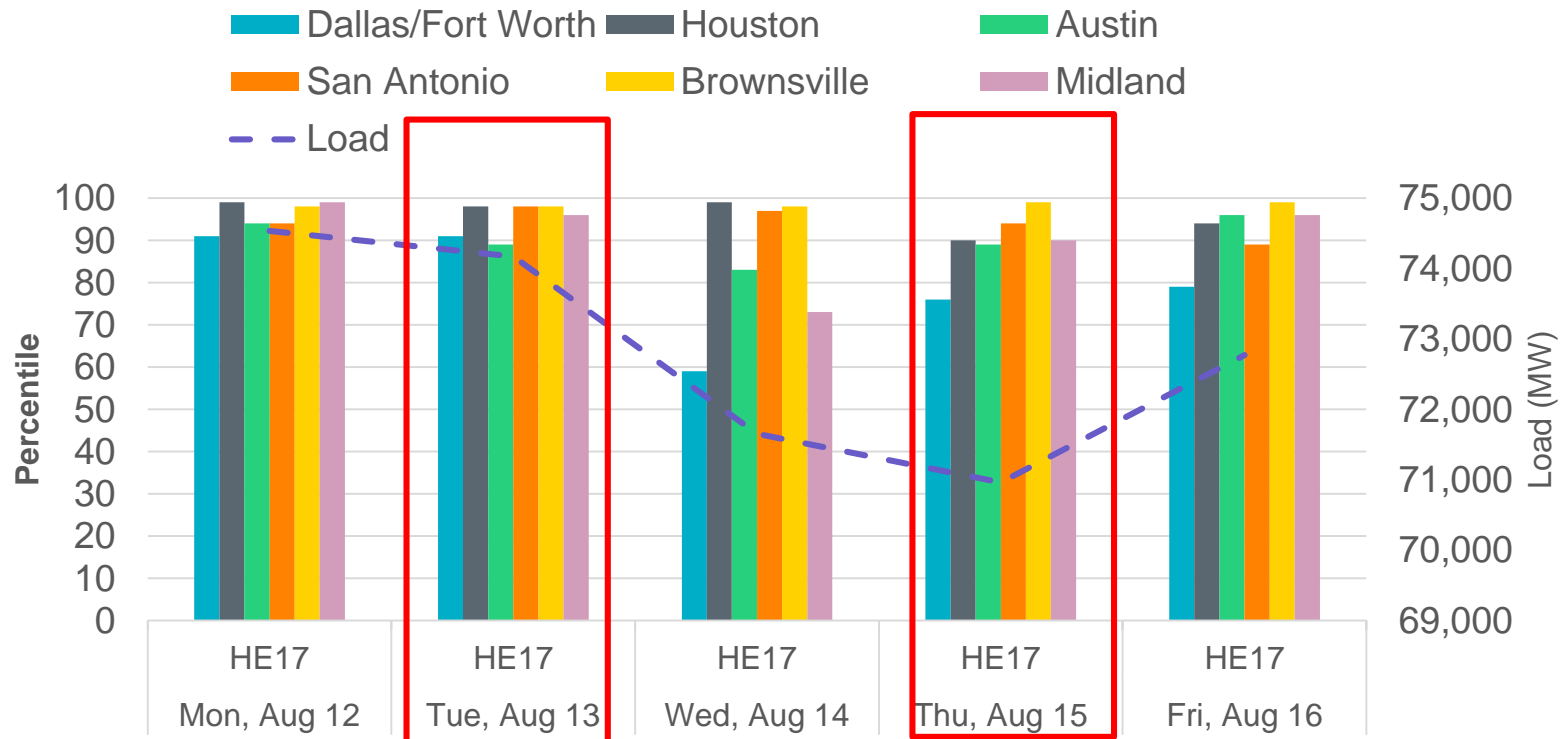
Average Planned Transmission Outages



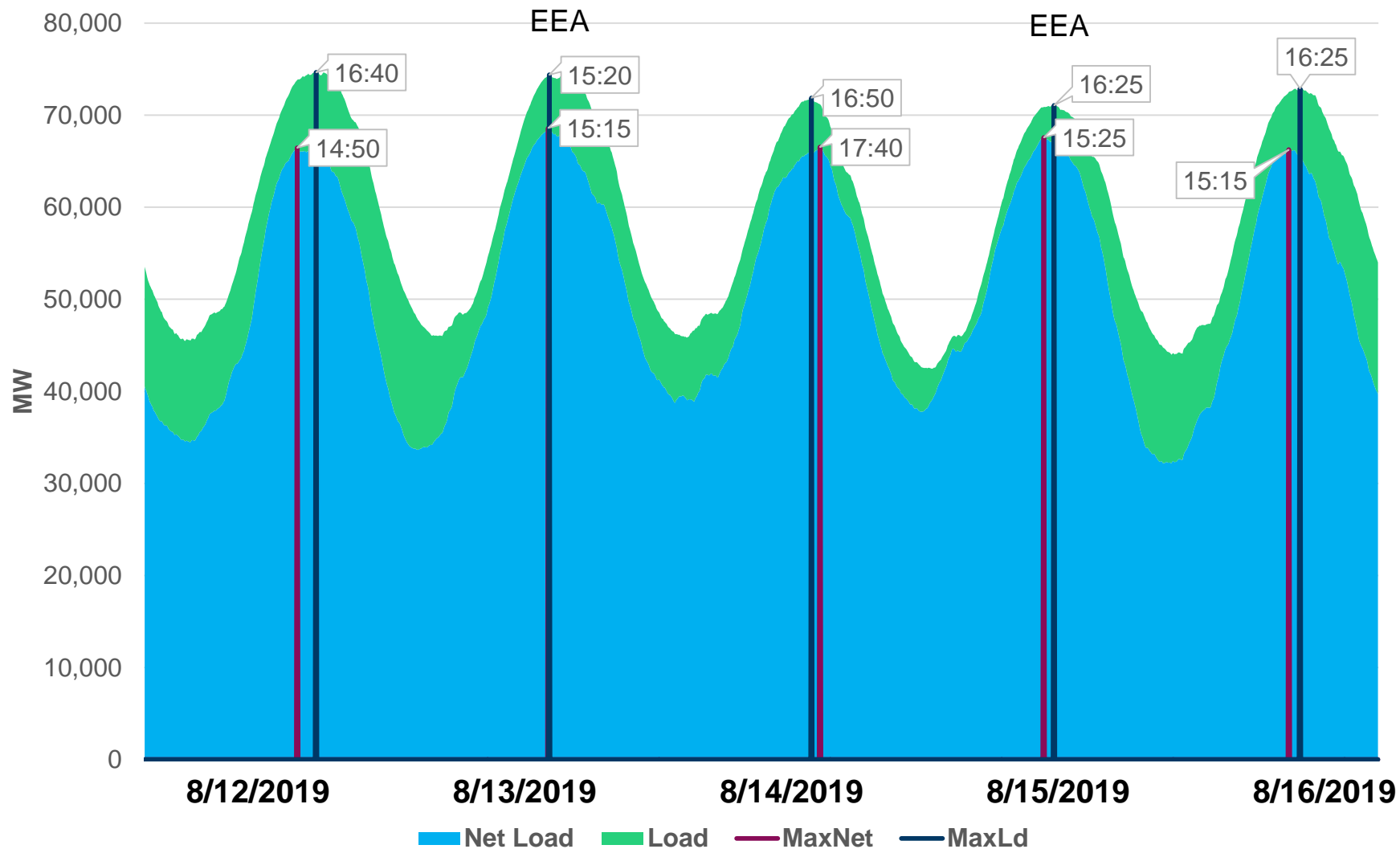
Peak Week

Temperature Trend at Major Load Centers

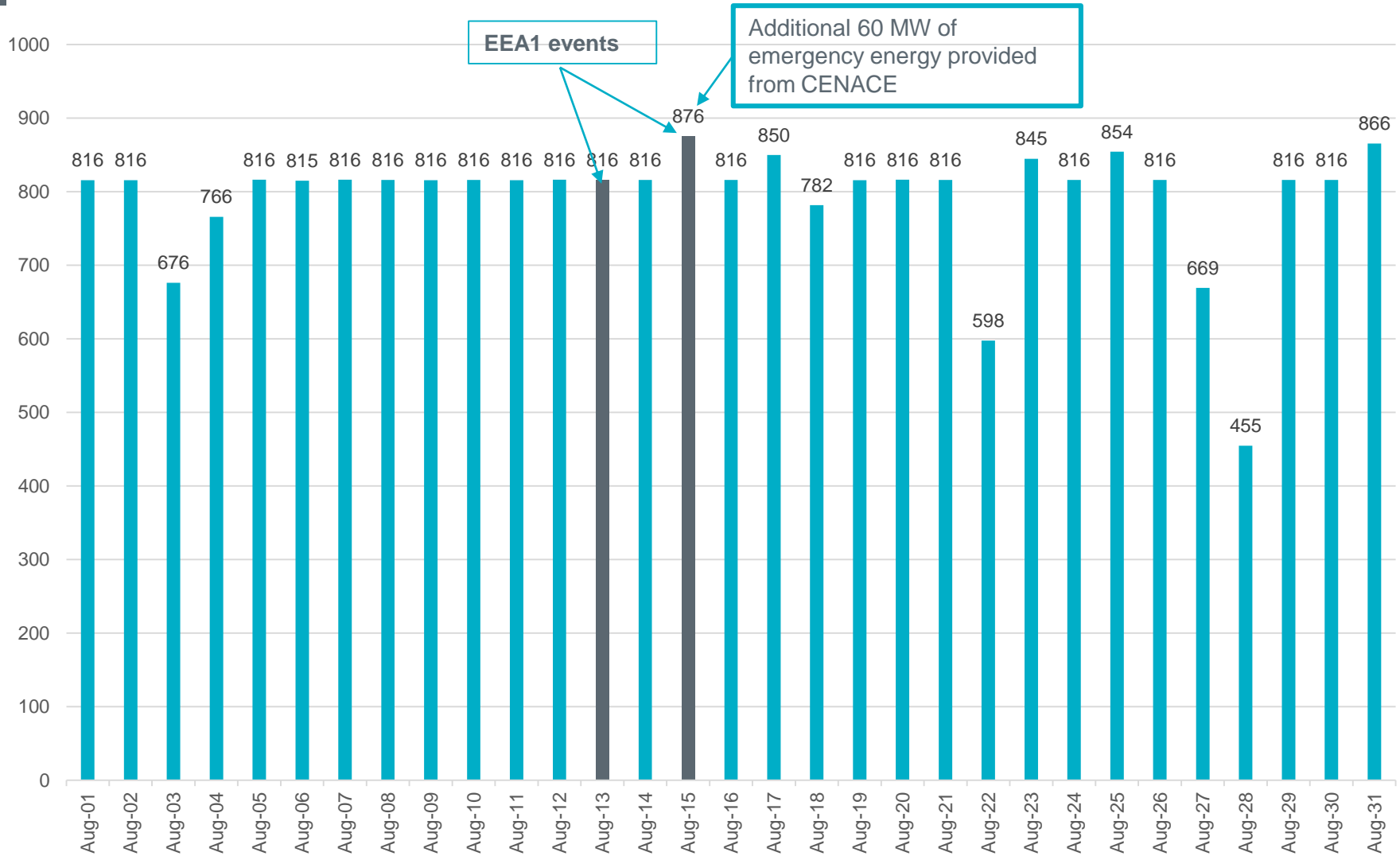
- Temperatures at most major load centers between Aug. 12 and Aug. 16 were at or above 90th percentile levels in comparison with what these regions have experienced in past summers (1950 thru 2019).



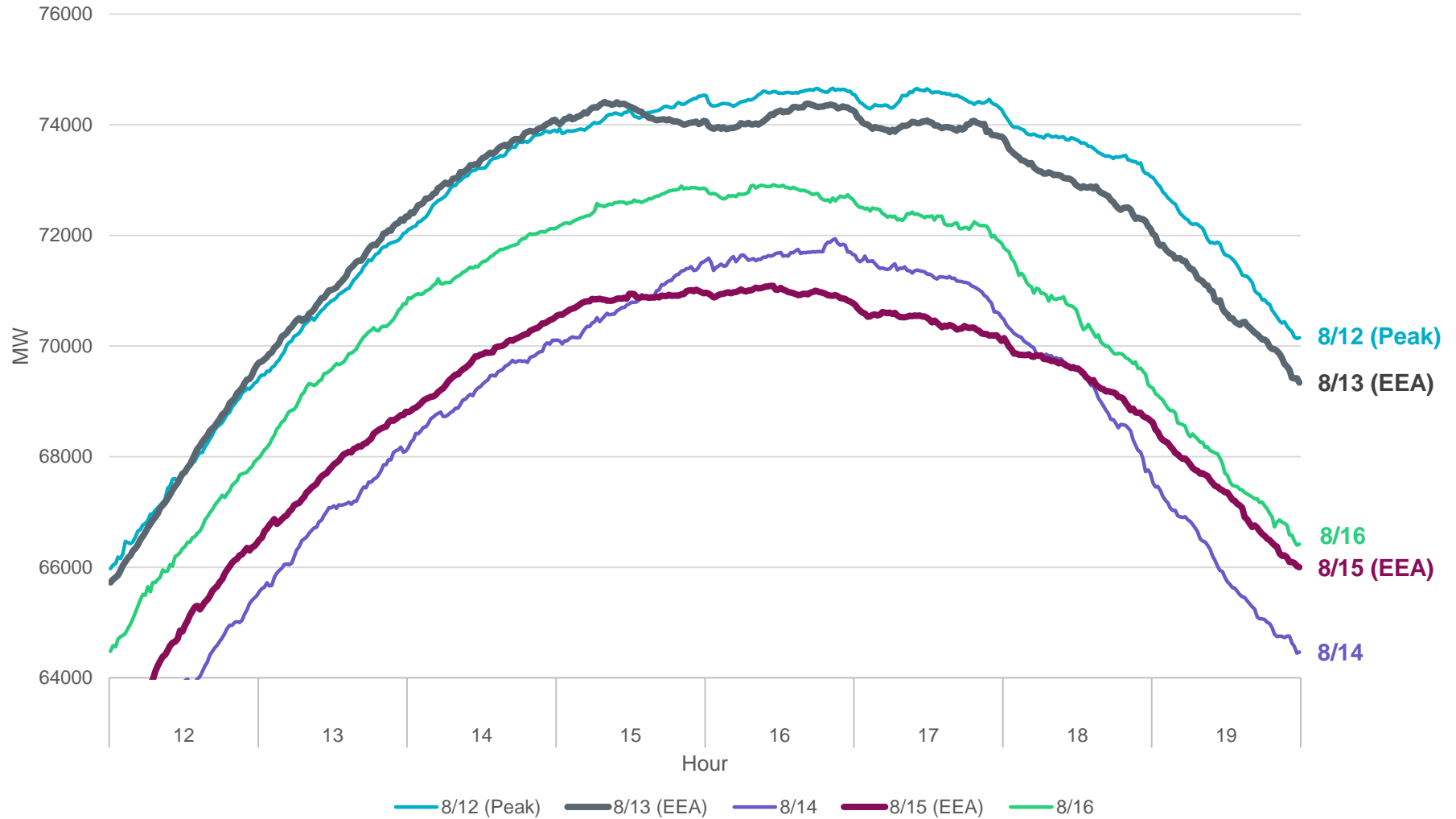
Difference of Load and Net Load Peak Times



Daily DC-Tie Schedule for August at Peak Hour



Load Patterns – 13:00-20:00 on 8/12-8/16



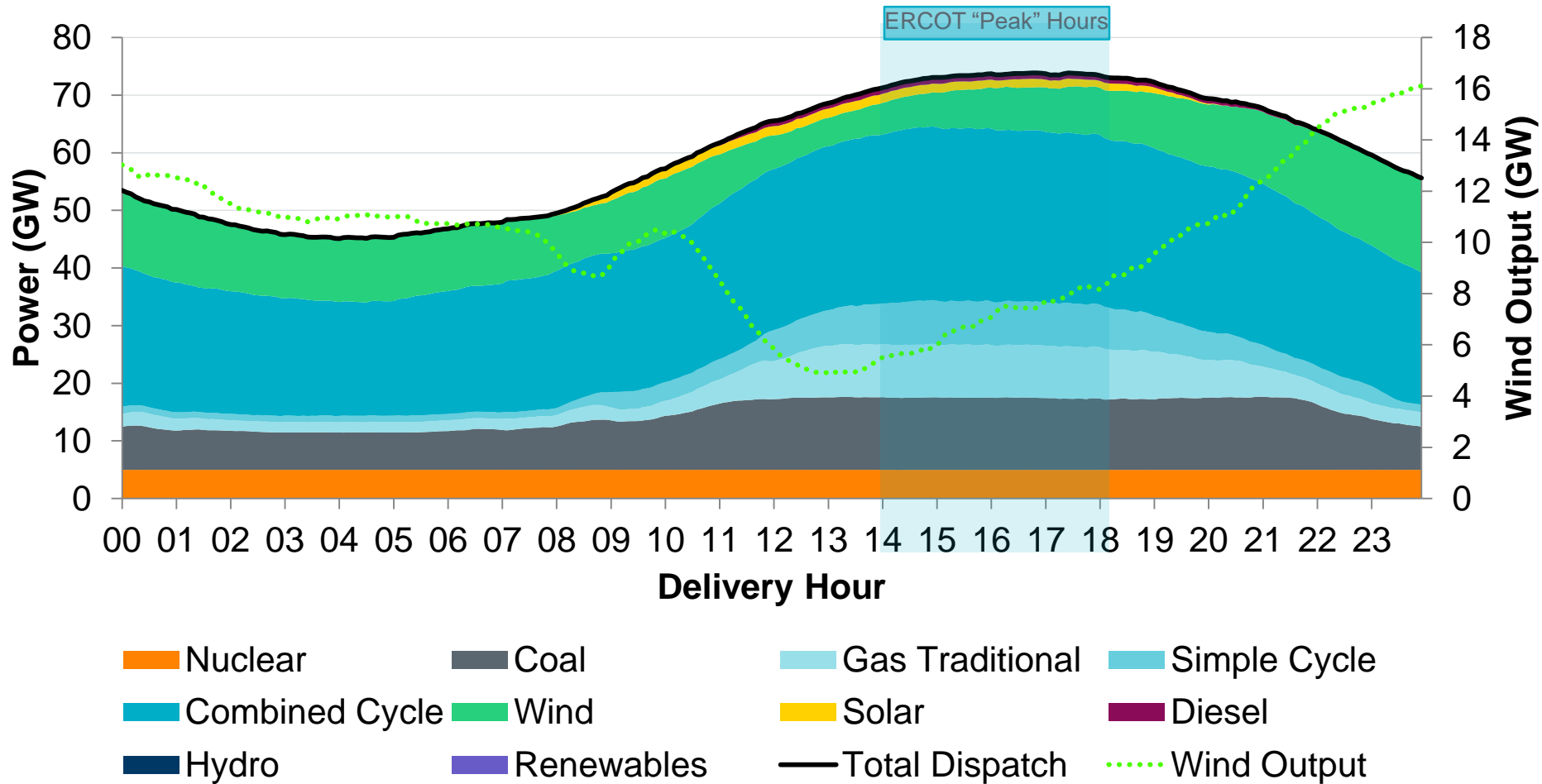
Preliminary Load Reduction Observations for Peak Week

- The information needed to accurately evaluate demand response during 2019 is not yet available.
 - Customer-level data is needed to evaluate the occurrence and load reductions in response to various factors. Data and results for summer are expected to be available by December 2019.
- Reductions shown below are estimates of the total of all load reduction (including ERS, 4CP and for high prices), calculated using regression baseline estimates of ERCOT total load.
 - Load reductions are small relative to the total load, so the accuracy of the load reduction estimates is relatively low.

Date	Characteristics	Max RT Load Zone SPP	Estimated HE 17 Load Reduction
Aug. 12	Actual 4CP Day	\$6,537	2,500 MW
Aug. 13	EEA1/Near 4CP	\$9,159	3,100 MW
Aug. 14	-	\$1,807	200 MW
Aug. 15	EEA1	\$9,053	1,800 MW
Aug. 16	Near 4CP	\$1,583	1,600 MW

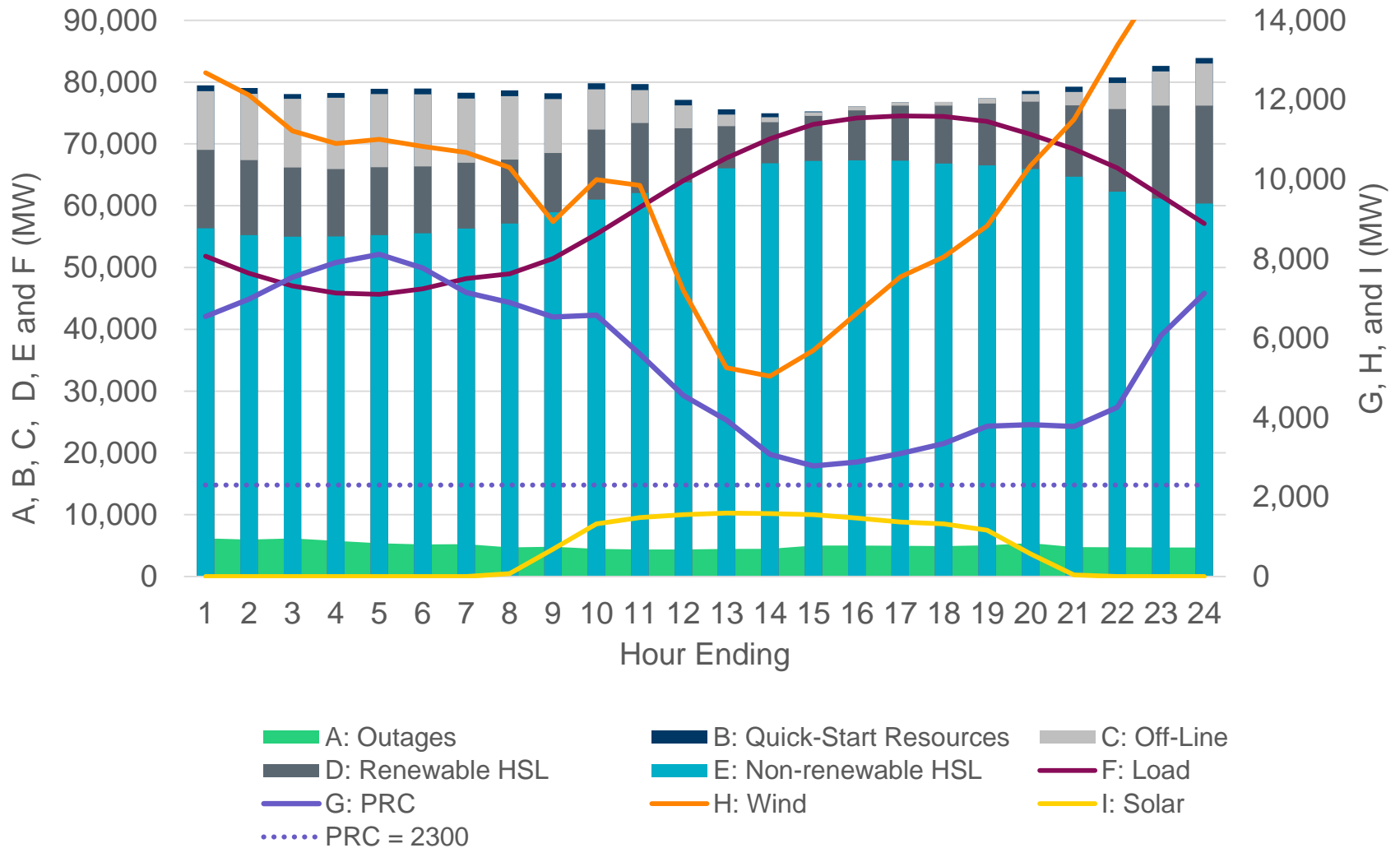
Aug. 12 – Peak Day

Closer Look at Peak Demand Day of Aug. 12



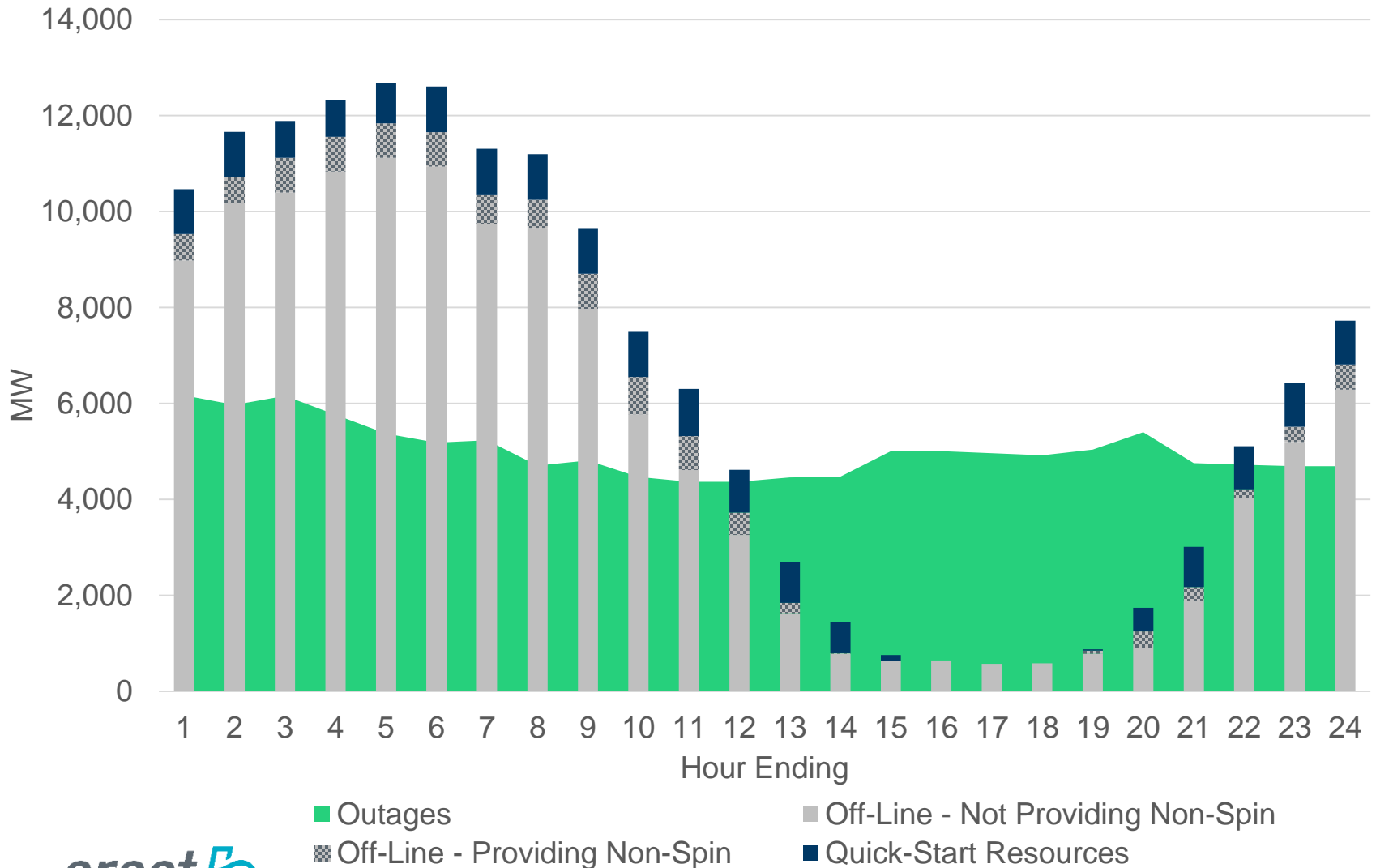
Closer Look at Aug. 12 – Peak Day

Hourly Average Demand, Capacity, and Reserves on 8/12/2019



Closer Look at Aug. 12

Off-Line Resources and Resources on Outage on 8/12/2019



The Summer 2019 Seasonal Assessment of Resource Adequacy (SARA) Values vs. Actuals at Peak Demand

	2019 Actual Peak Demand (8/12/19)	Final 2019 Summer SARA*	Difference
Total Resources, MW	80,098	78,930	1,168
Thermal and Hydro	64,401	65,526	(1,125)
Private Use Networks, Net to Grid	3,203	3,437	(234)
Switchable Generation Resources	2,837	2,726	111
Wind Capacity Contribution	7,447	4,898	2,549
Solar Capacity Contribution	1,394	1,405	(11)
Non-Synchronous Ties	816	938	(122)
Peak Demand, MW	74,666	74,853	(187)
Reserve Capacity, MW	5,432	4,077	1,355
Total Outages, MW	3,972 **	4,226	(254)
Extreme Outage Scenario		6,891	
Capacity Available for Operating Reserves, MW	1,460	(149)	1,609

Largest absolute difference

Source: [Final 2019 Summer SARA](#)

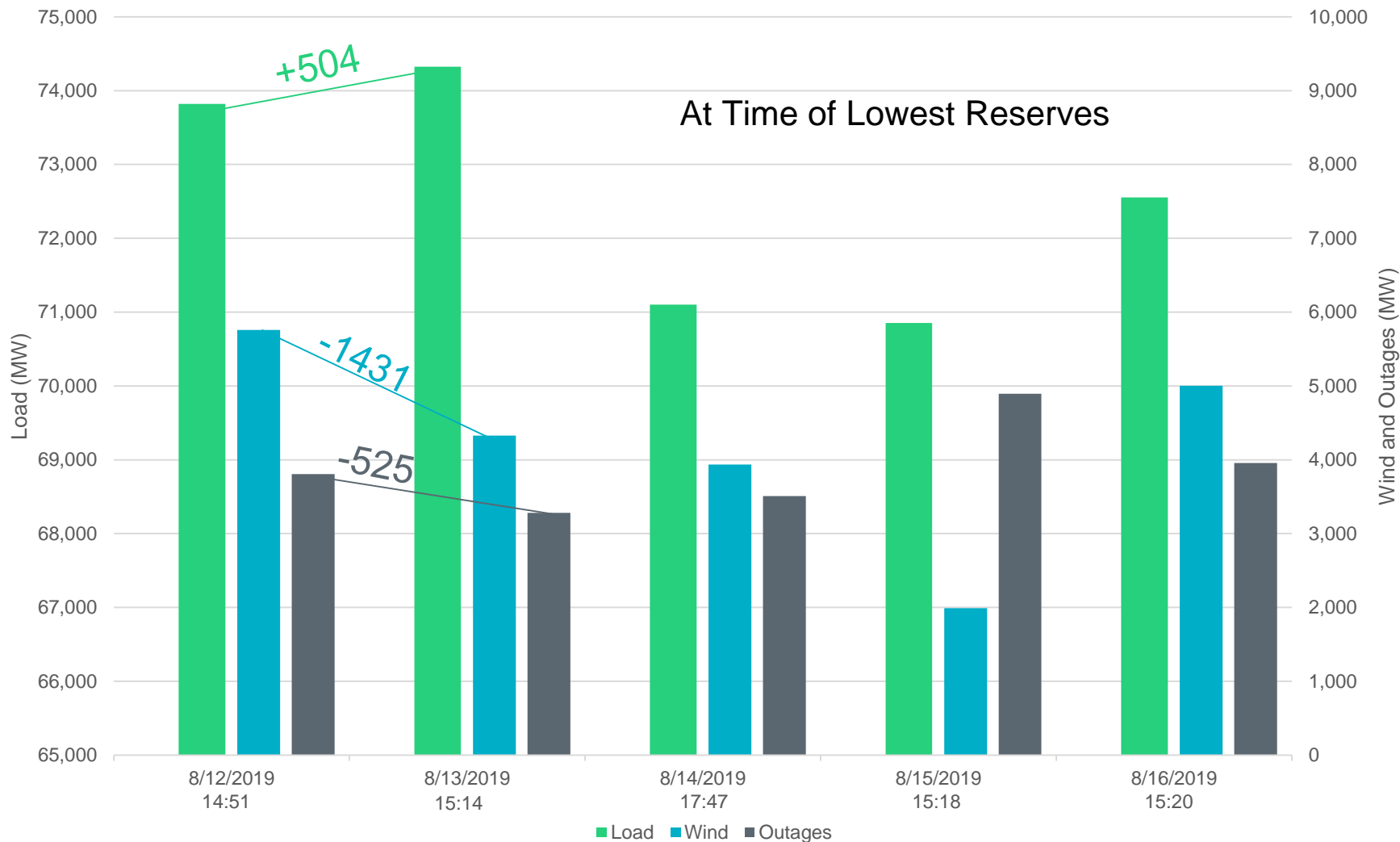
*The totals for the Final 2019 Summer SARA column combine multiple rows into a single row in some cases. (E.g., already in-service Thermal and Hydro Resources with planned Thermal and Hydro Resources).

**The outage information in this table was extracted on Sept. 16, 2019.



EEA1 Days

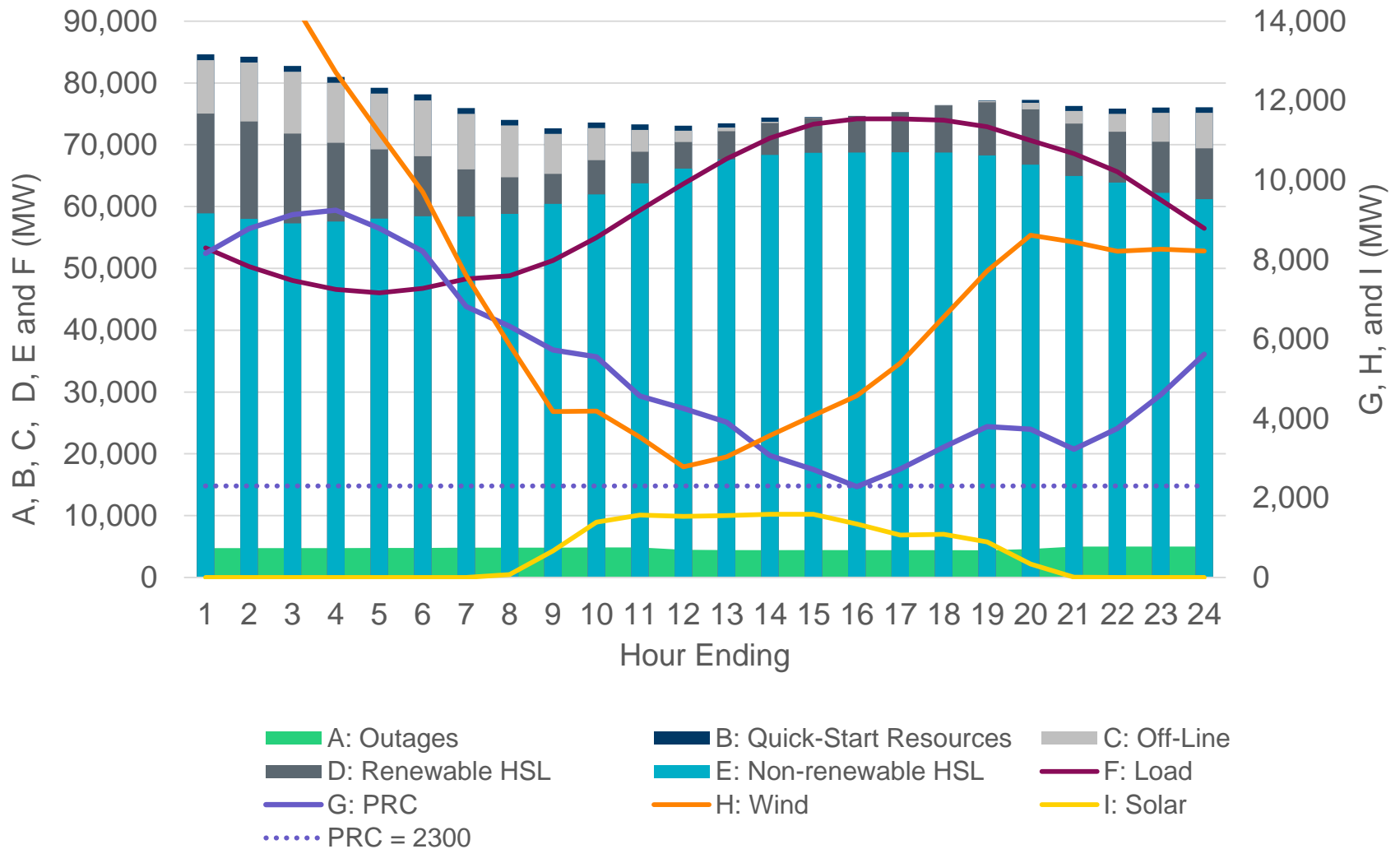
Load, Wind, and Outage Differences – 8/12-8/13



Outages Shown are non-IRR Outages

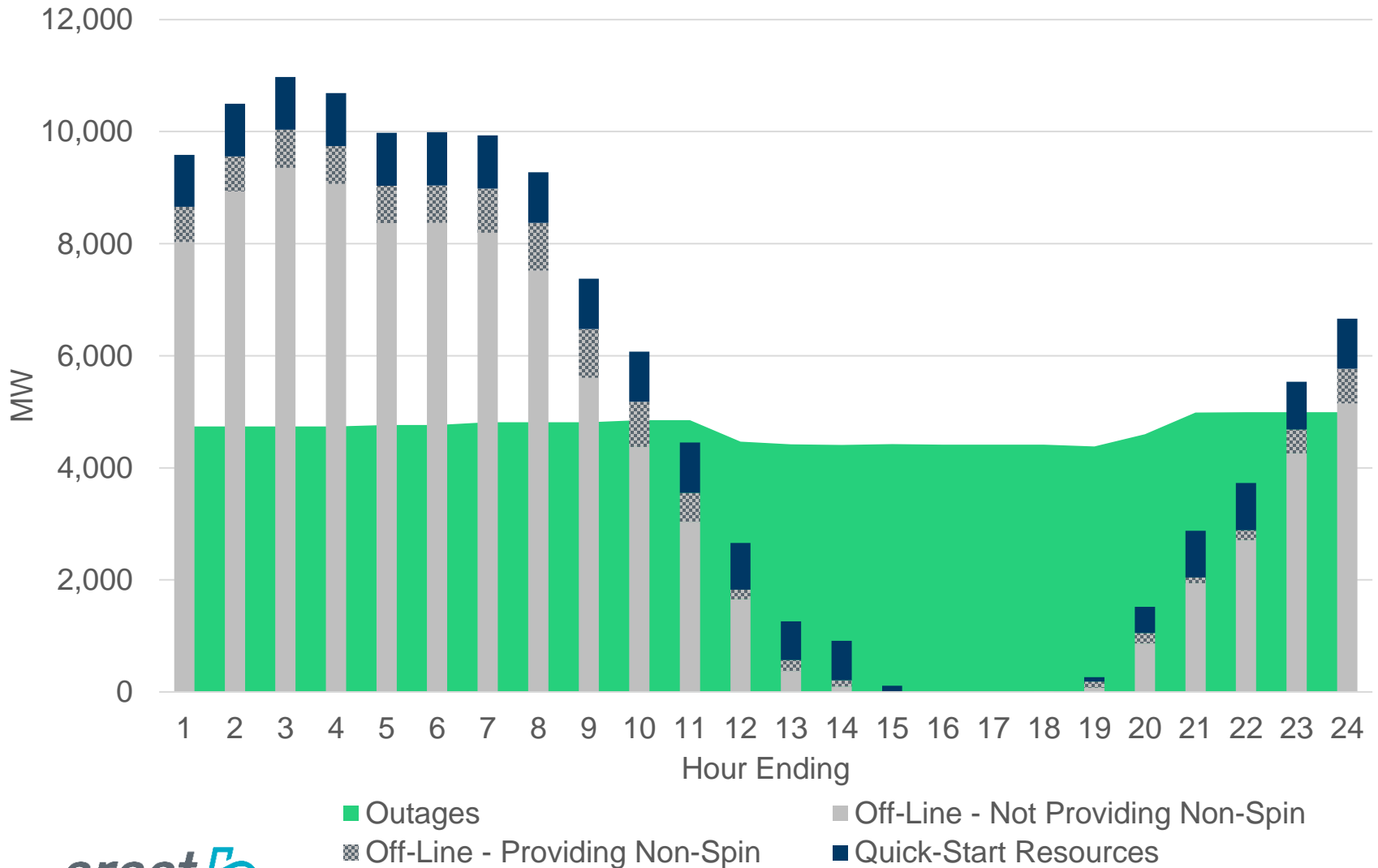


Hourly Average Demand, Capacity, and Reserves on 8/13/2019



Closer Look at Aug. 13 – EEA1 Day

Off-Line Resources and Resources on Outage on 8/13/2019

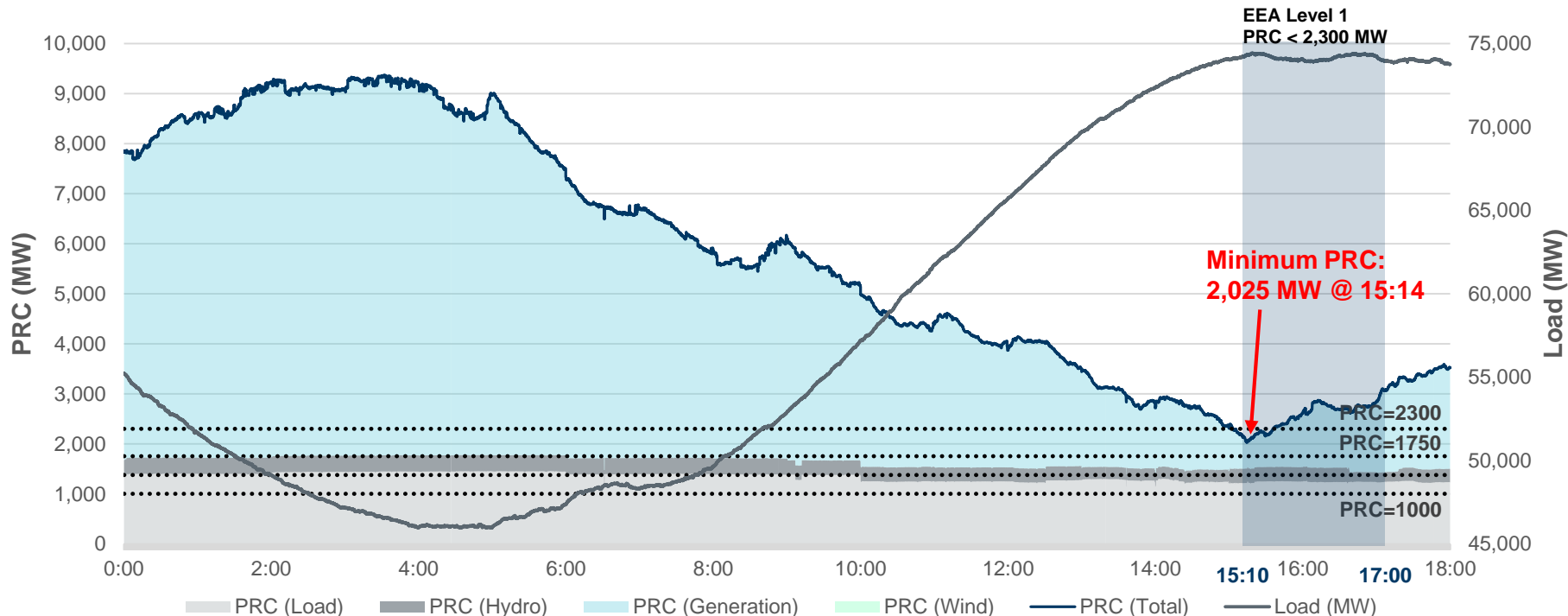


Aug. 13 EEA Level 1 Timeline

Time	Events
05:00	Issued OCN for HE 14 to HE 18
13:50	Issued Advisory for PRC < 3,000 MW
14:46	Sent VDIs to 5 hydro units for HE17
14:55	Issued Watch for PRC < 2,500 MW
15:15	Issued EEA1 for PRC < 2,300 MW
15:16	Issued a public appeal for voluntary energy conservation
15:16	Deployed all 10-min and 30-min ERS (926 MW)
15:56	Recalled 10-min ERS (93 MW)
16:02	Re-deployed 30-min ERS
16:14	Recalled 30-min ERS
17:00	Cancelled EEA1
17:30	Cancelled Watch
18:00	Cancelled Advisory and OCN

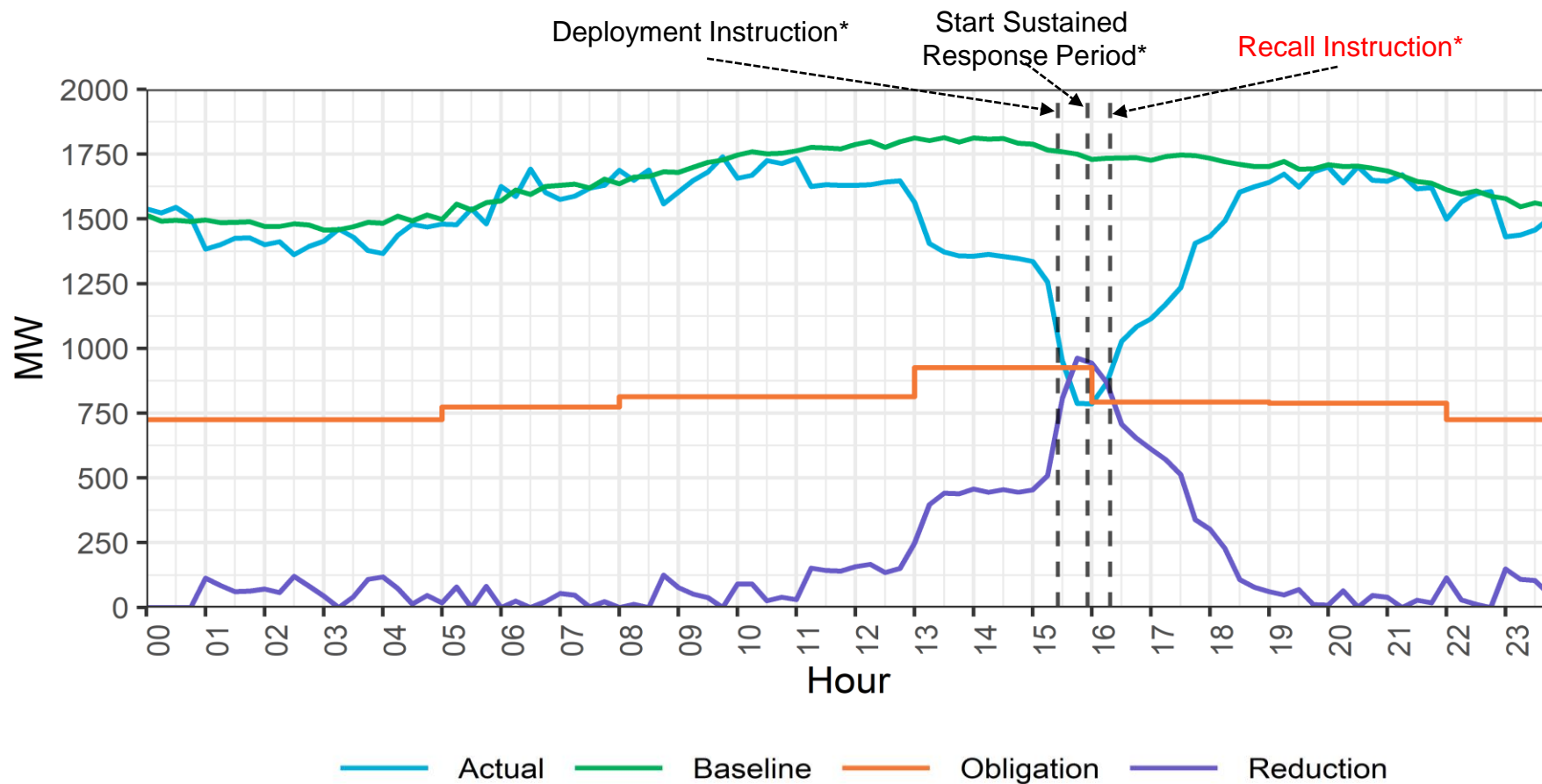
PRC on Aug. 13 – EEA1 Day

- ERCOT declared EEA Level 1 at 15:10 when the PRC was 2,156 MW.
- PRC was under 2,300 MW for 35 minutes.
- EEA Level 1 continued for 1 hour and 50 minutes until deployed resources were recovered and reserves sustained an upward trend.



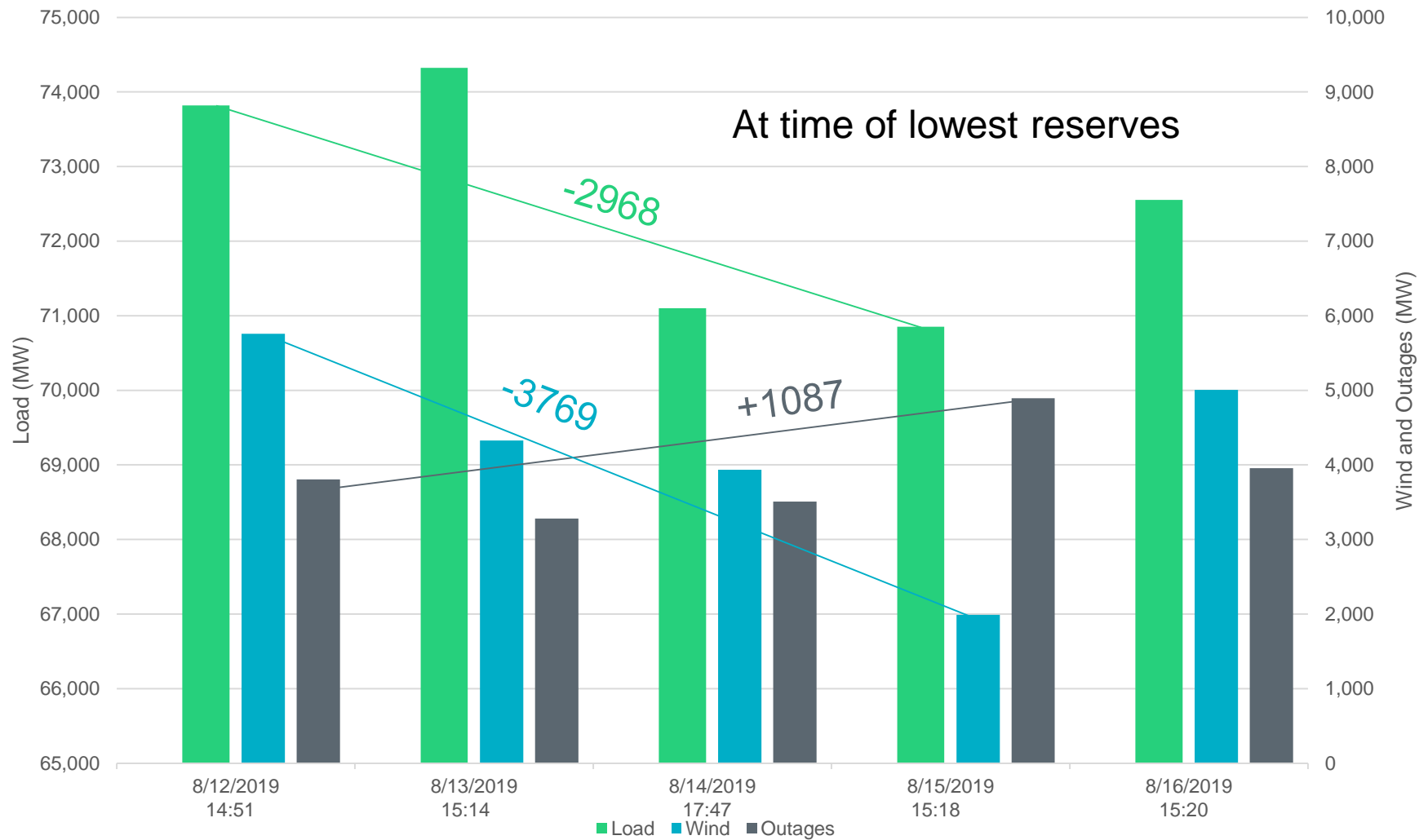
Aug. 13 ERS Deployment

- Fleet-wide, ERS deployment exceeded the obligation.



*Refers to ERS-30 only. All MW quantities include both ERS-30 and ERS-10.

Load, Wind, and Outage Differences – 8/12-8/15

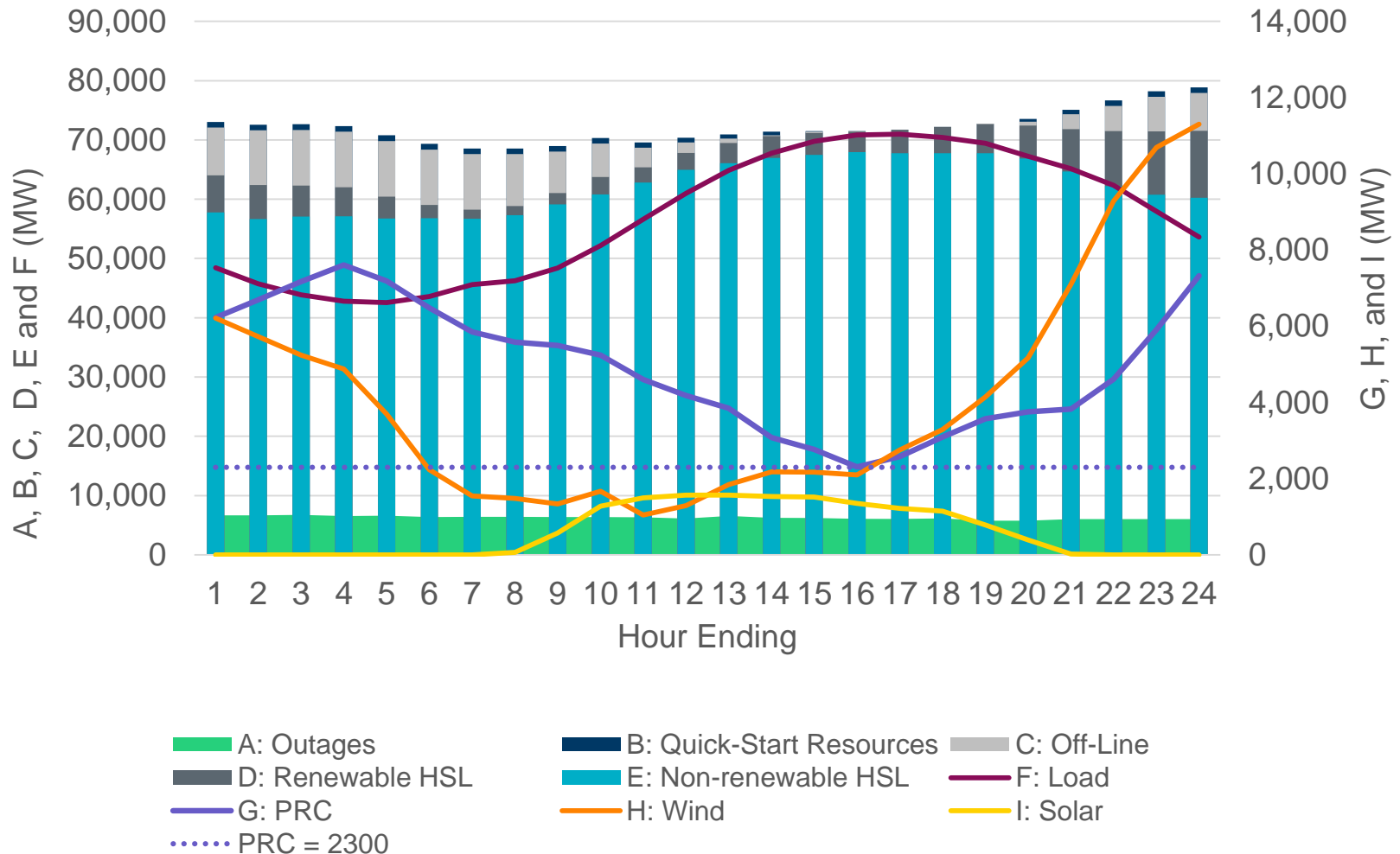


Outages shown are non-IRR outages



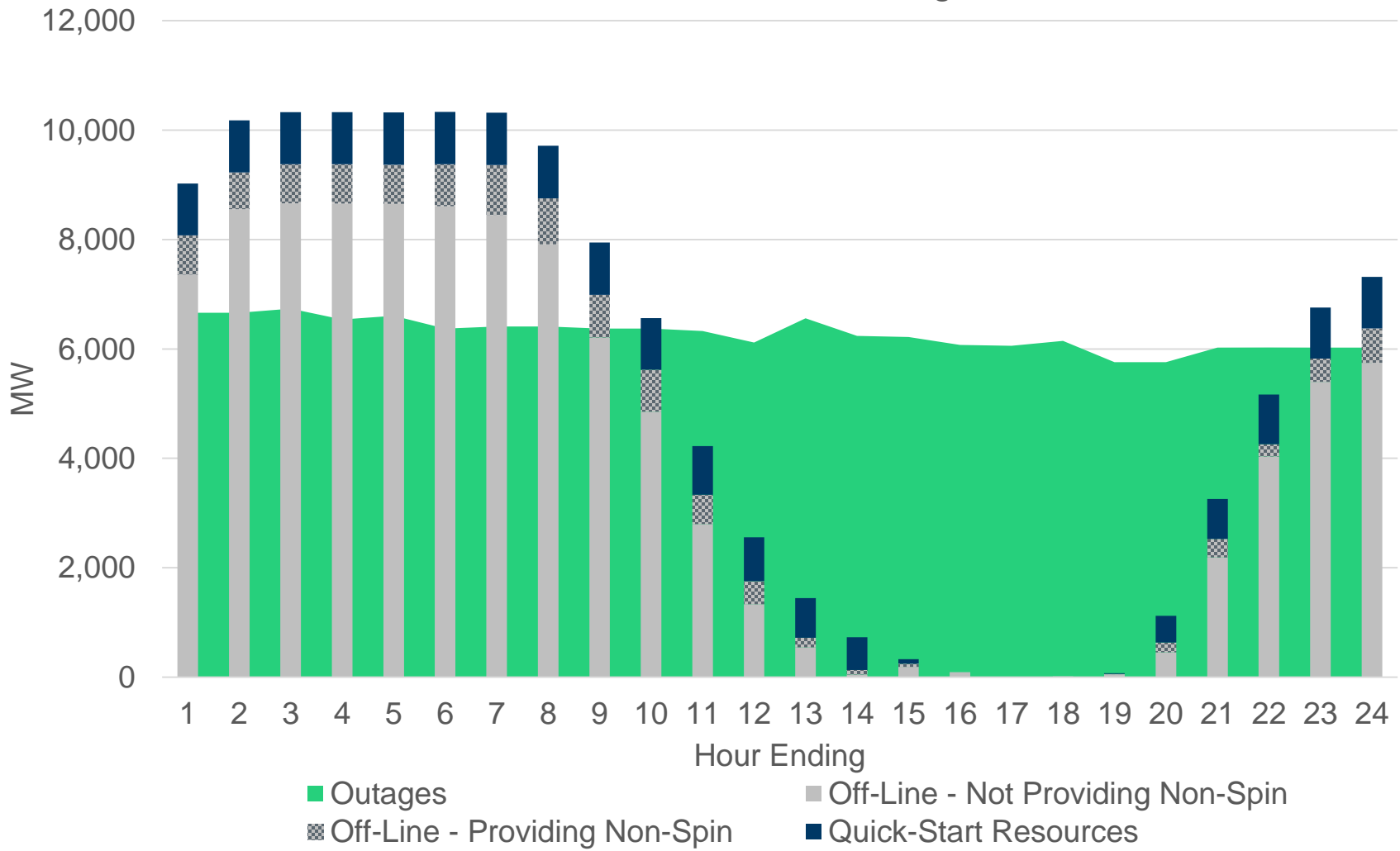
Closer Look at Aug. 15 – EEA1 Day

Hourly Average Demand, Capacity, and Reserves on 8/15/2019



Closer Look at Aug. 15

Off-Line Resources and Resources on Outage on 8/15/2019

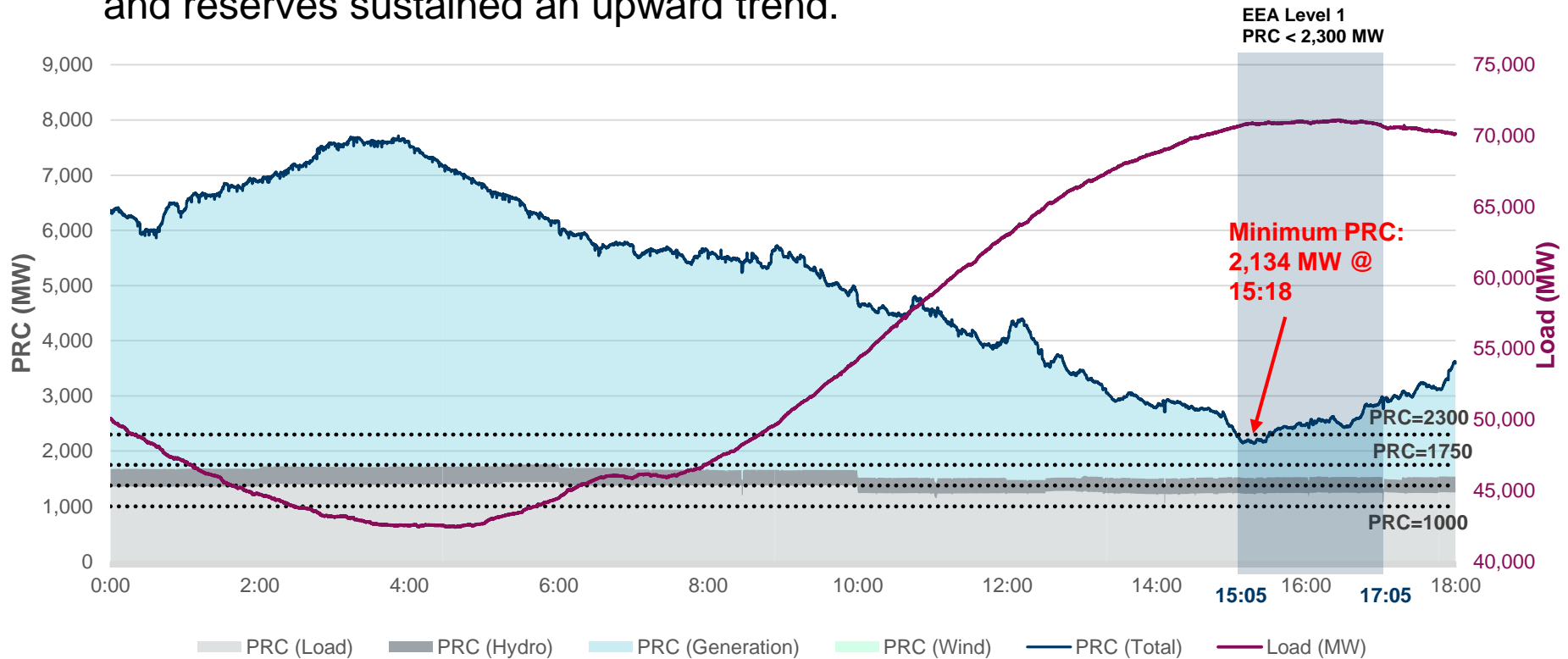


Aug. 15 EEA Level 1 Timeline

Time	Events
05:00	Issued OCN for HE 14 to HE 18
13:30	Issued Advisory for PRC < 3,000 MW
15:00	Issued Watch for PRC < 2,500 MW
15:05	Declared EEA1 for PRC < 2,300 MW
15:05	Issued a public appeal for voluntary energy conservation
15:11	Deployed 30-min ERS (833 MW)
15:30	Sent VDI for emergency energy across the Railroad DC-Tie to ERCOT
15:53	Sent VDIs to keep two generators online for HE16 and HE17
16:54	Recalled all 30-min ERS
17:05	Terminated EEA1
17:15	Ended VDI for emergency energy across the Railroad DC-Tie
17:35	Cancelled Watch
18:00	Cancelled Advisory and OCN

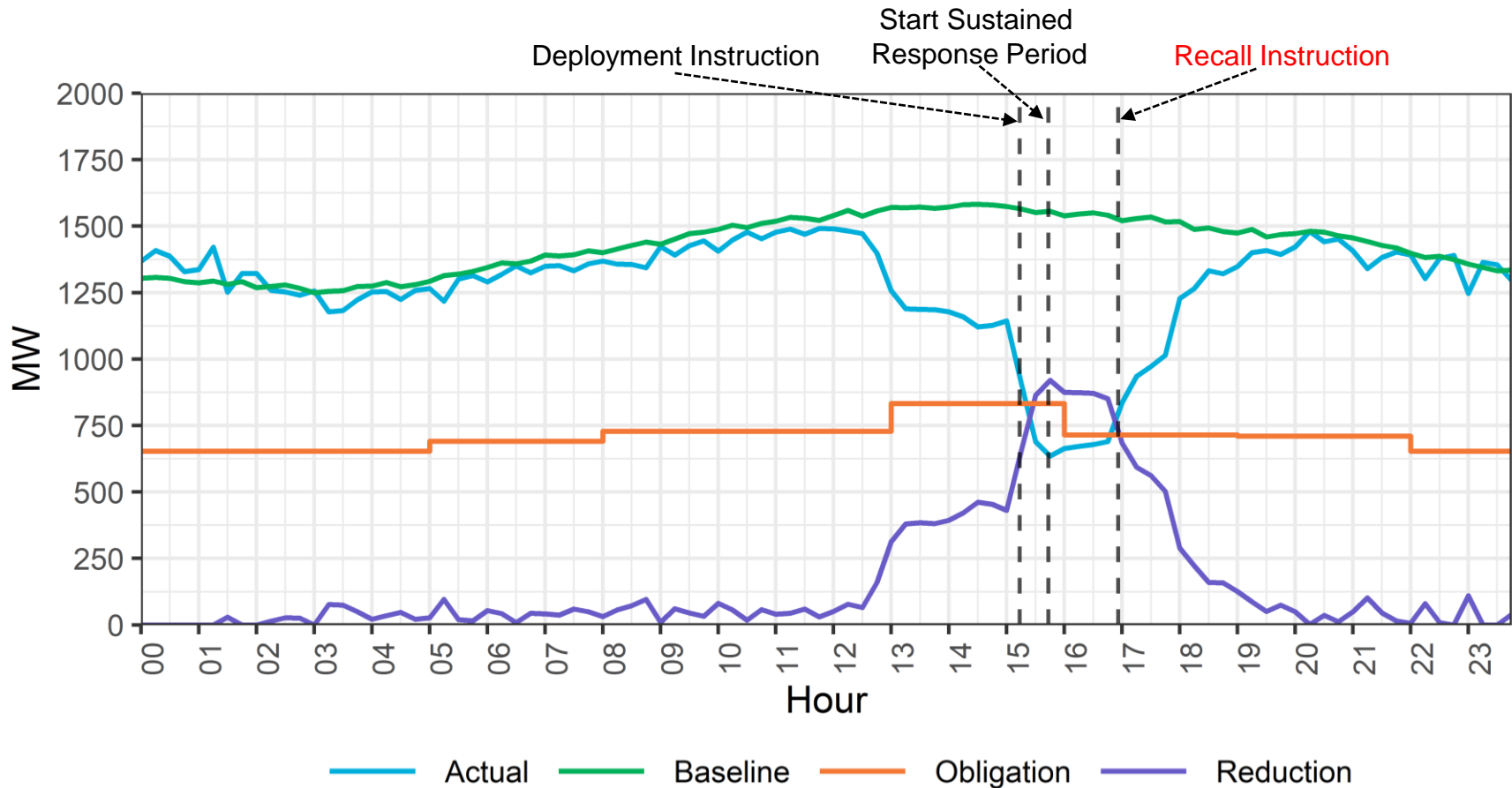
PRC on Aug. 15 – EEA1 Day

- ERCOT declared EEA Level 1 at 15:05 when the PRC was 2,245 MW.
- PRC was under 2,300 MW for 26 minutes.
- EEA Level 1 continued for 2 hours until deployed resources were recovered and reserves sustained an upward trend.



Aug. 15 ERS Deployment*

- Fleet-wide, ERS deployment exceeded the obligation.

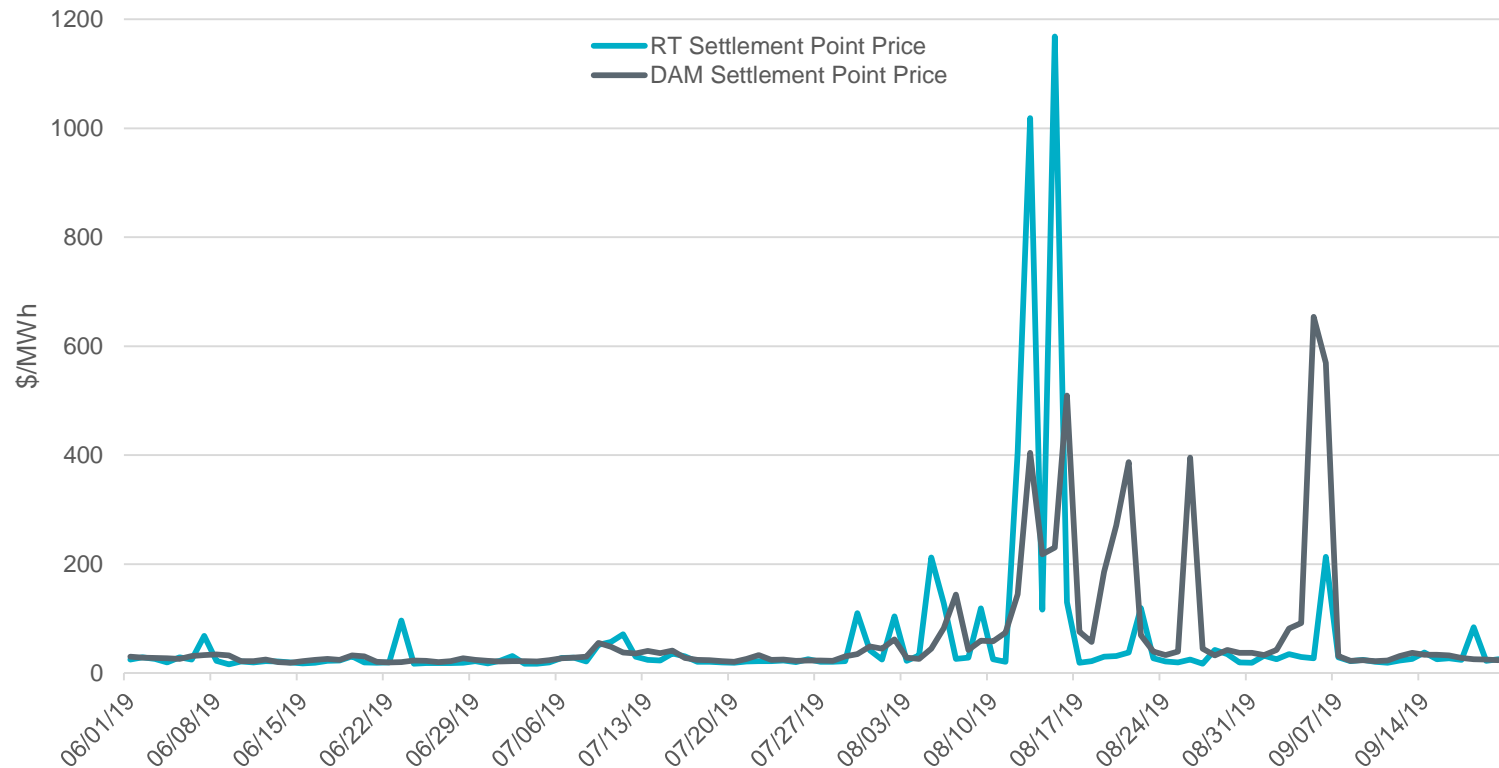


*Note: Weather sensitive and non-weather sensitive ERS-30 deployed

Commercial Information

Day-Ahead Market (DAM)/Real-Time (RT) Price Convergence

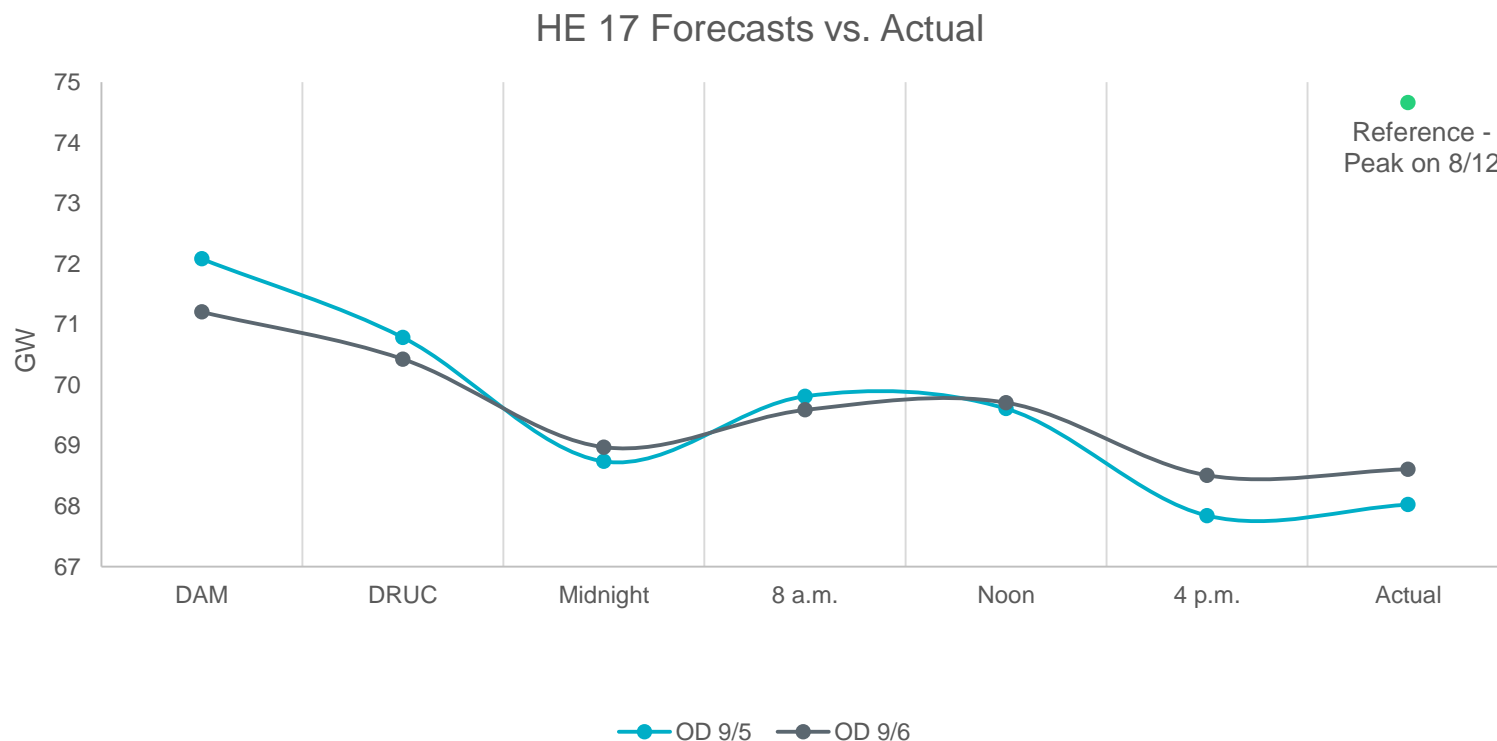
- On average, price convergence was within normal range over the summer.
- Day-to-day, significant volatility was observed.



Daily Average Unweighted Settlement Point Prices at ERCOT 345kV Hub Average

Load Forecast for Sept. 5 and 6

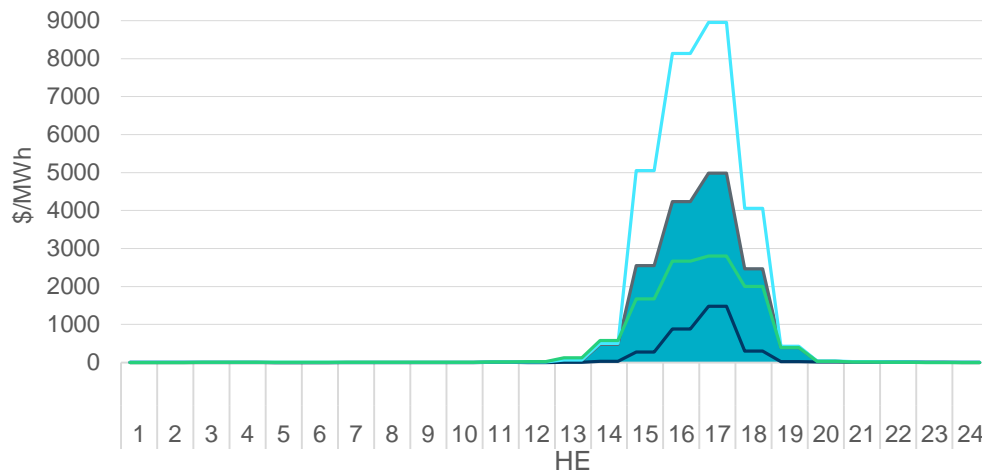
- On both days, demand was lower than forecast due to lower than expected temperatures.



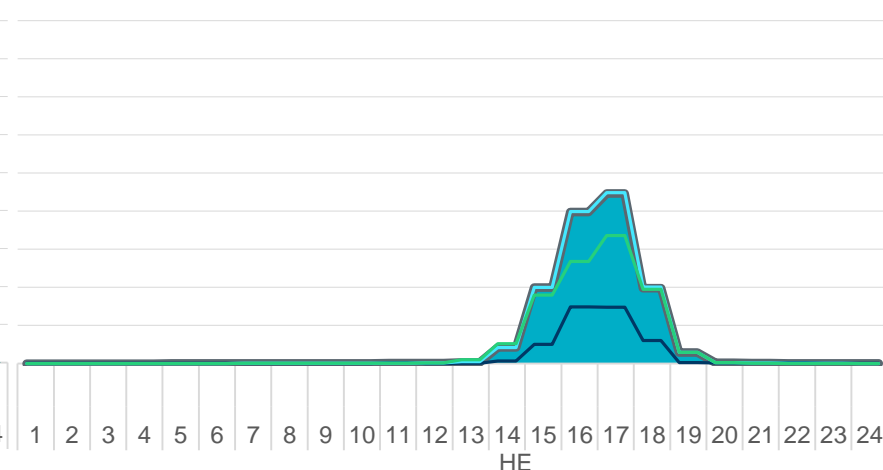
Record DAM Prices (Closer Look at Sept. 5 and 6)

- Day-Ahead Market (DAM) for Operating Day (OD) 9/5 had record prices.
 - The RRS price was a result of a \$6k offer plus ~\$3k opportunity cost of energy.
- The overall increase in prices can be attributed to three things:
 - Increase in both bid quantity and bid prices
 - Prices in the offer stack increased earlier in the day compared to recent days
 - Decrease in Ancillary Service quantities offered into the DAM
- DAM for OD 9/6 saw more RRS quantities offered in, though the energy bid/offer curves were similar to OD 9/5. Therefore, energy prices were similar for the two days, but the RRS price was lower.

OD 9/5/2019 – DAM System Lambda and AS MCPCs



OD 9/6/2019 – DAM System Lambda and AS MCPCs



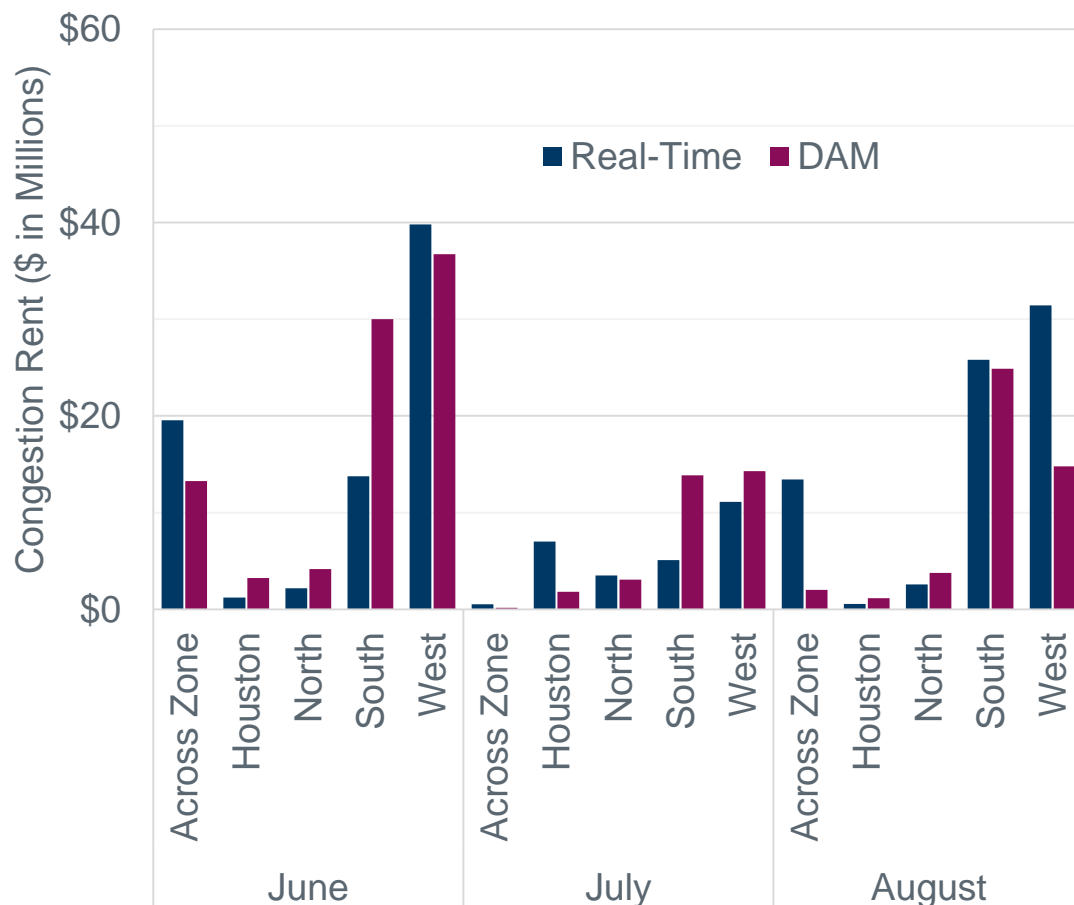
SystemLambda REGUP REGDN RRS NSPIN

SystemLambda REGUP REGDN RRS NSPIN



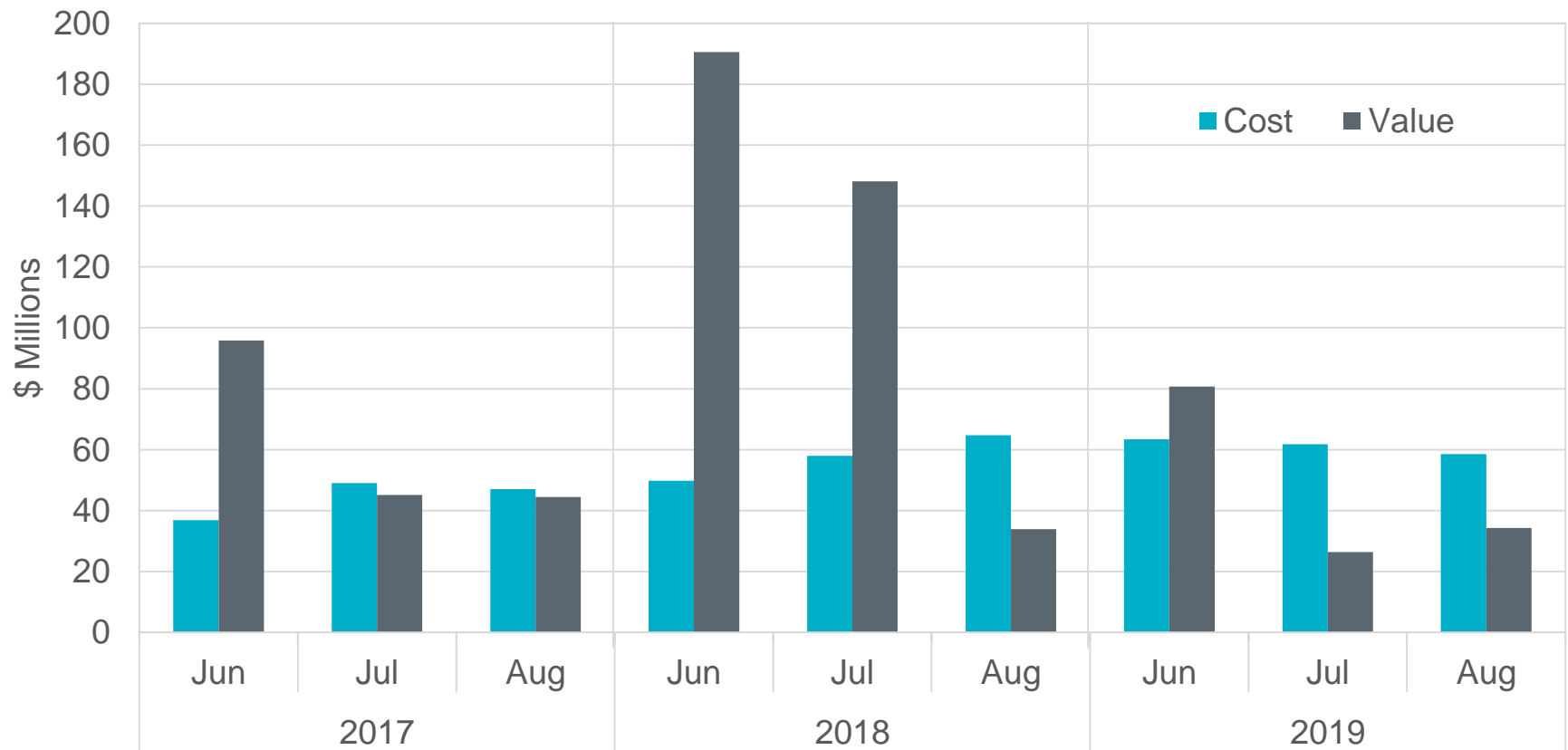
Day-Ahead and Real-Time (RT) Market Congestion Rent

Summer 2019 Congestion Rent by Zone

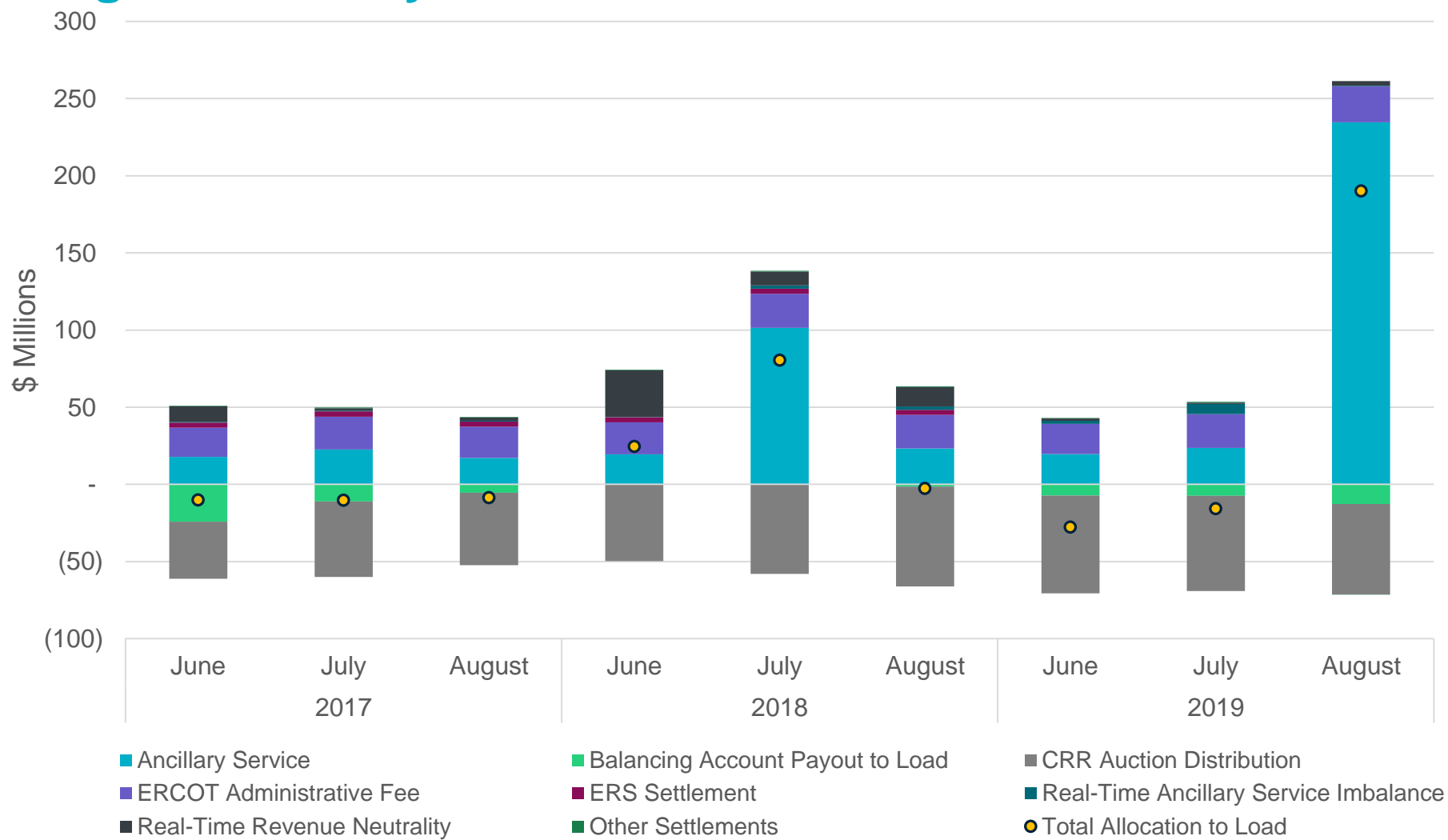


- In summer 2018 there was significant congestion, as well as CRR underfunding in July and higher RT Revenue Neutrality Allocation (RENA) overall.
- Summer 2019:
 - No CRR underfunding
 - RENA down to ~\$5M from ~\$50M last summer
 - 2019 RT congestion rent totaled approx. \$180M; for 2018, it was \$350M

Congestion Revenue Rights (CRRs) Cost vs. Value

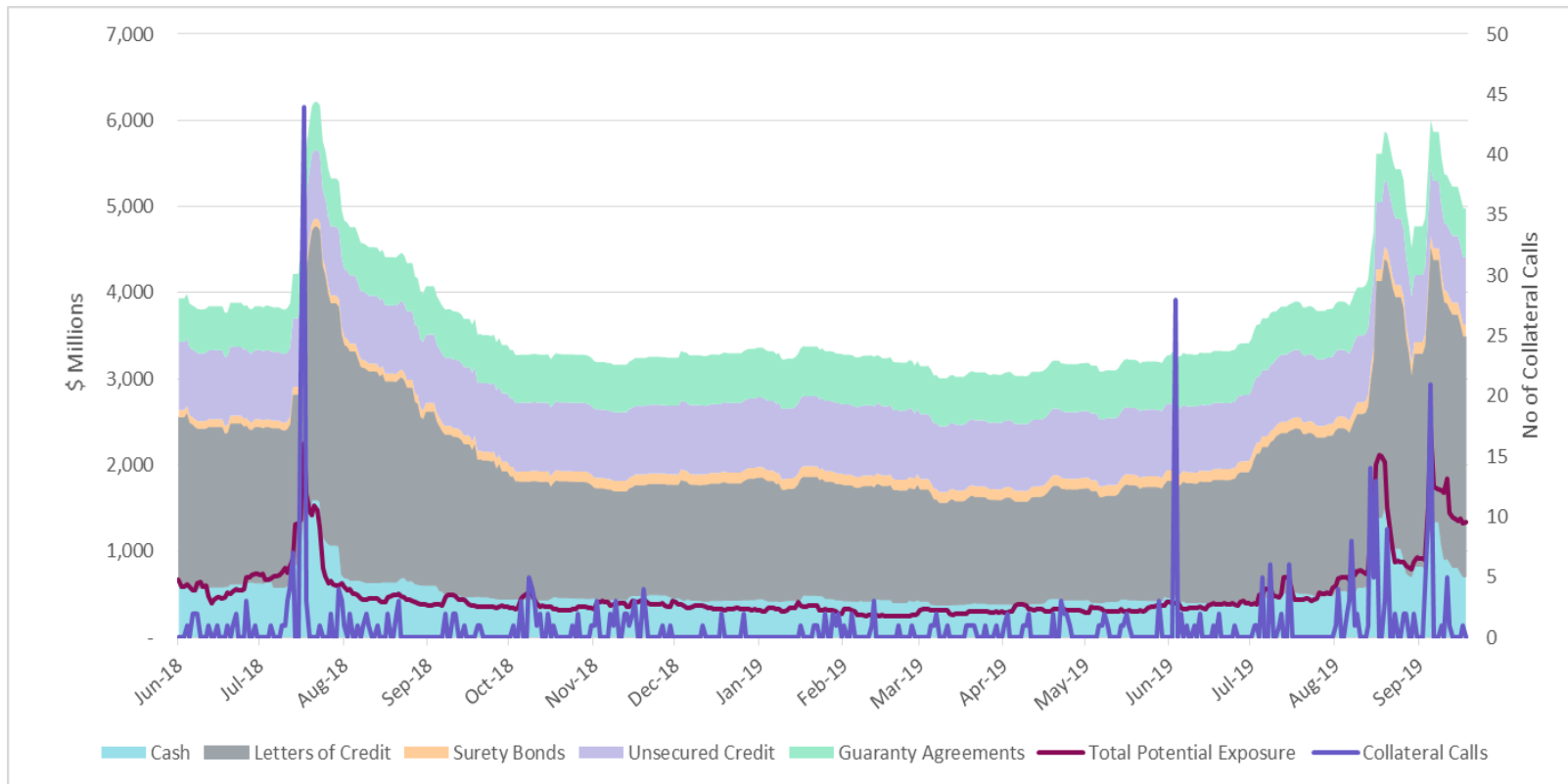


Net Allocation to Load Increased in August Due to Higher Ancillary Service Costs



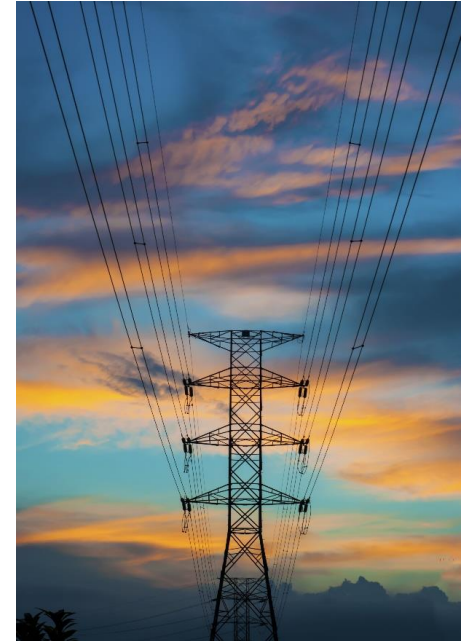
Collateral

- In July, Total Potential Exposure (TPE) and collateral calls increased due to significantly high Forward Adjustment Factors, which are driven by Intercontinental Exchange (ICE) North Hub prices.
- In September, the increase in TPE and collateral calls was driven more by the increase in ERCOT Real-Time and Day-Ahead prices.



Other Summer Observations

- Despite record prices, there were no mass transitions.
 - There was only one default of a Market Participant (MP) with no load or generation (occurred in September).
 - On one occasion in September, ERCOT was required to short-pay the market due to a MP's failure to pay an invoice. ERCOT drew from the MP's available financial security, refunded MPs and no default occurred.
 - The Credit Work Group is evaluating this event and re-examining surety bonds as financial security.
- Switchable generation coordination agreements enabled effective communications during EEAs.
- Distributed generation increased net output by an estimated 150-200 MW during Aug. 12-16 peaks.



Future Opportunities

- Filed NOGRR to clearly allow operators to deploy smaller amounts of RRS at a time.
- Use event data to inform a review of ERS assumptions used for the reliability deployment price adder, such as the 10-hour recall period.
- Continue to focus on Real-Time Co-optimization, while assessing whether any improvements can be made to the existing processes in the interim.
 - RTC would have increased reliability and economic efficiency by:
 - Improving the ability of SCED to dispatch NFRC ahead of frequency responsive capacity to maintain higher levels of PRC and reduce the duration of the two EEA1 events on Aug. 13 and 15.
 - Allowing more efficient dispatch of lower-cost capacity that was reserved behind the High Ancillary Service Limit (HASL) and procurement of AS from higher-generating cost capacity during tight conditions.
 - Reducing the number of ramp-constrained dispatch conditions.

Future Opportunities

- Consider changes to OCN issuance procedures.
- Discuss switchable generation scenarios and possible market rule changes.
- Continue to work with gas generators and gas companies on coordinated communication processes.
- Work with fossil fuel generators on gathering appropriate emission limitation data to assist in enforcement discretion requests.
- Complete summer demand response study by December 2019.