Residential Demand Response *Workshop II*

ERCOT Staff

June 16, 2025

Agenda

- Recap of Workshop #1 Design Discussions
- Key Themes from Stakeholder feedback on Residential Demand Response Program (from May 2 Workshop)
- The need for utilizing residential demand response
- Proposed Design Updates and Refinements
- Settlement and Credit
- Review of Analysis and Information Requests
- Next Steps

Recap: Conceptual Overview

- A residential DR program that provides an incentive payment to Retail Electric Provider (REP) (as well as Non-Opt-In Entity (NOIE)) Qualified Scheduling Entities (QSEs) based on Residential Demand Response performance at times of system need
  - Focus on high seasonal net load hours
  - Targets participation from smart/programmable devices in residential households
  - Incentive payment to encourage participation and offset program development and administration costs
- Participation is voluntary and REPs/NOIEs are free to utilize the DR capacity in the program to respond on other days and for other needs (e.g. avoided cost during high price days)
- Performance measurement uses ESIID data* to determine the kWh load reduction from a baseline during the highest net peak load hours in each season

First Workshop

- ERCOT held its first workshop on May 2, 2025
- Reviewed conceptual proposal and high-level design for program
- Q&A and request for feedback
- Workshop related to NOIE participation held on May 16

Key Themes from Stakeholder Feedback

- Market Integration
  - ERCOT has not clearly defined the specific system need this program addresses, raising concerns about potential market distortion and reduced investment in dispatchable resources (Vistra, TCPA, TIEC)
  - Stakeholders argue that DR should be integrated within existing market signals rather than introduced as an out-of-market solution (Vistra, TIEC).

- Eligibility
  - Clarity is needed on whether customers already receiving DR bill credits from their utility are eligible for this program (PEC, Base Power).
  - Support for voluntary participation by NOIEs and MOUs. Stakeholders emphasized avoiding overlapping or redundant DR compensation (TPPA, PEC).
  - REPs encouraged keeping eligibility simple and managed through existing retail programs (Reliant, TEAM).

Key Themes from Stakeholder Feedback cont.

- Data Requirements
  - Several NOIEs expressed concerns about the feasibility of providing 15-minute interval data due to metering and infrastructure limitations (TPPA, TEC, PEC).
  - Requests were made to ERCOT to allow alternate data methods for participation, especially for smaller utilities (TPPA, TEC).
  - Other stakeholders supported using hour data and ESIID-level analysis as proposed (Recurve).

- Measurement and Settlement
  - General support for ERCOT's approach using site-matched baselines and 15-minute interval data to assess performance (Recurve, TAEBA).
  - Stakeholders emphasized the importance of transparency and cost-effective implementation (Recurve, Carrier).
  - Seasonal settlement design was supported by many as a practical approach (TAEBA).

Key Themes from Stakeholder Feedback cont.

- Program Design
  - Stakeholders expressed the importance of a simple, flexible program design to avoid barriers to participation, especially for small utilities (TEA, TEC, TPPA).
  - Requests to minimize telemetry and administrative burden were consistent across feedback (Reliant, TEAM).
  - Some suggested that ERCOT launch the program with a low-barrier framework and revise over time through NPRRs (TEAM).

- Participation Model
  - Strong stakeholder support to allow third-party QSEs to participate directly, enabling broader and more automated participation (CPower, Leap).
  - NOIEs requested that participation be voluntary for MOUs, with no mandated involvement or cost recovery obligations (TPPA, PEC).
  - Some emphasized the need to preserve existing DR relationship and flexibility in enrollment pathways (Carrier, TPPA).

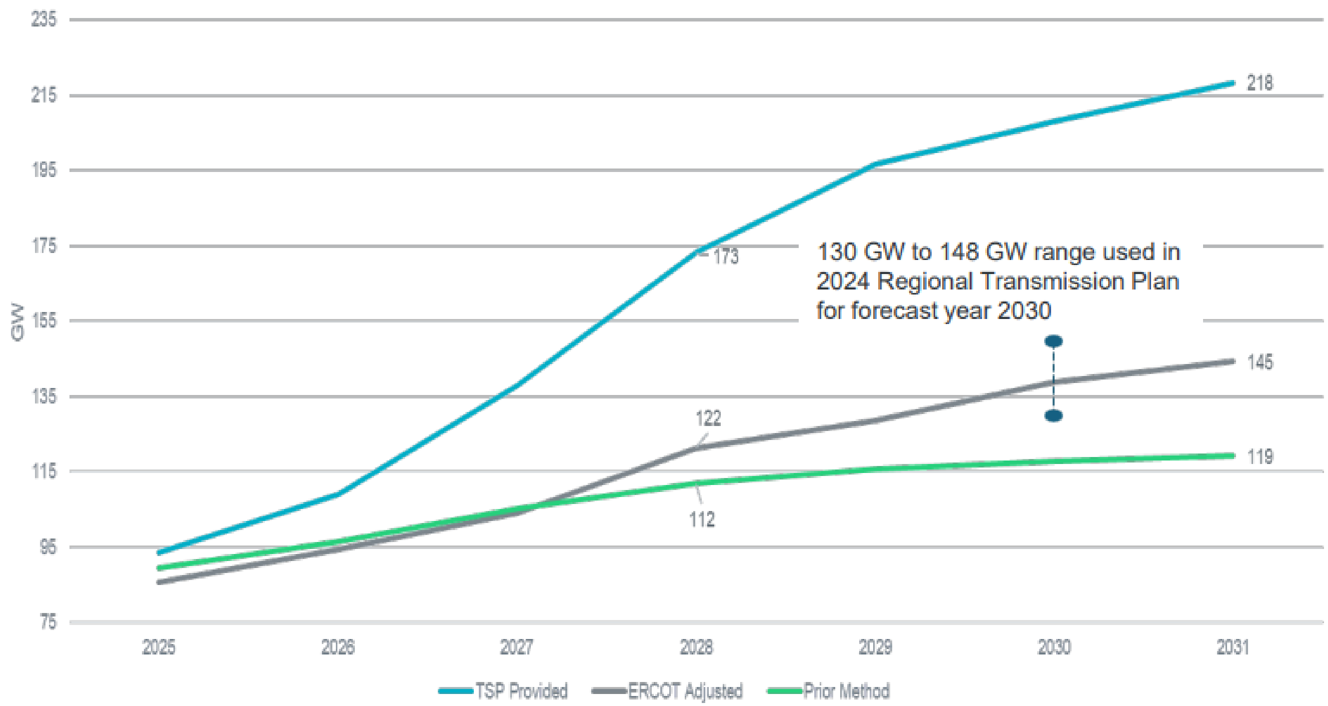
Key Themes from Stakeholder Feedback cont.

- Payment Design/Cost Allocation
  - Concern that the $140/kW year cap is too low to incentivize meaningful DR participation, particularly for advanced technologies (Carrier, TAEBA).
  - NOIEs objected to cost recovery from entities not participating, warning it could penalize MOUs unfairly (TPPA, PEC).
  - Multiple stakeholders recommended a hybrid payment model with both reservation and performance-based compensation (Carrier, TAEBA).
  - Some utilities preferred simpler payment models such as upfront bill credits (PEC).

- Consumer Protection
  - Stakeholders emphasized the need for explicit opt-in, clear communication of program participation, and the ability for customers to override device controls (OPUC).
  - NOIEs raised privacy concerns and warned that required data sharing could undermine customer trust in their utilities (TPPA).

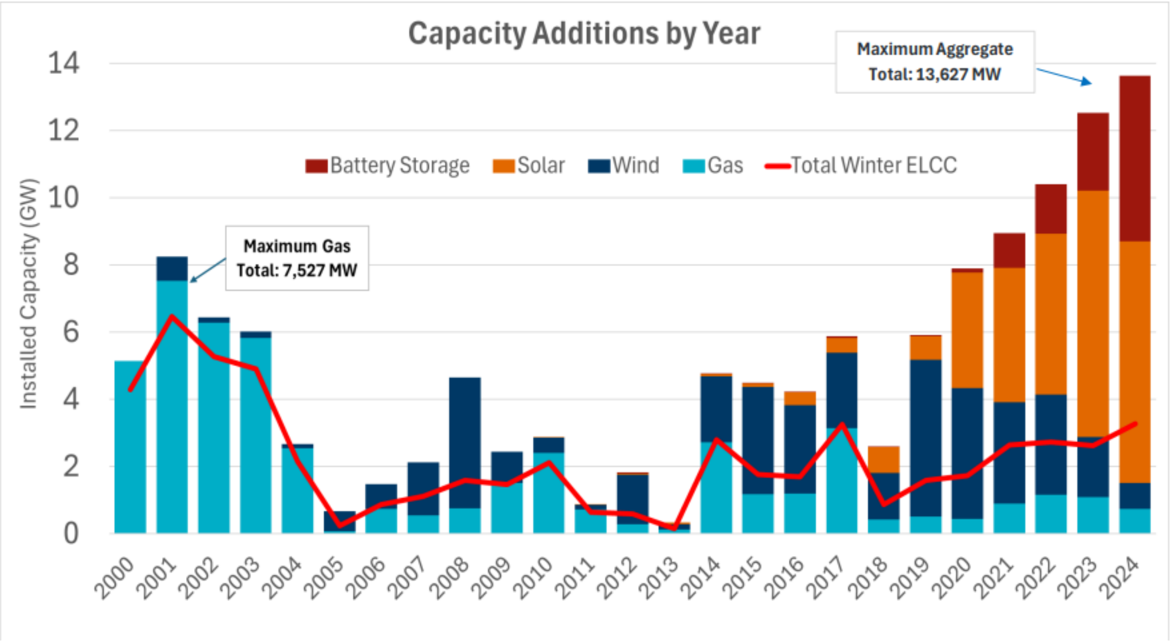
Managing Load Growth

Summer Peak Forecast Methodologies



- With the anticipated growth in load, utilizing additional capacity, particularly at times of high net load will be critical.

Historic Resource Capacity Additions



- During the early 2000s, more than 27,000 MWs of new gas generation was added to the system over a 5-year period
- In the last 3 years, almost 25,000 MWs of nameplate wind and solar generation were added to the system. This period includes about 9,000 MWHs of energy storage.
- These time periods of rapid Resource growth provide some insight into the amount of new supply that can be reliably interconnected over a short period of time. **Fully utilizing all resource types will be critical.**

Need for Residential DR

- Residential Demand Response (DR) represents a resource that is not fully enabled today
  - This includes increasing DR from ‘smart’ devices (ie thermostats, EV charges, batteries, water heaters and pool pump switches)
- There is an opportunity for ERCOT to collaborate with stakeholders to develop a program that can incent and grow residential DR capacity as an additional resource that can help support system reliability
  - Developing a Residential DR Program is a key ERCOT corporate priority for 2025
- Program design should aim to adhere to the following framework

✓ **Quick to develop**

✓ **Simple to administer**

✓ **Popular to join**

✓ **Cost-effective**

Market Impacts: Considerations for Residential DR

- Residential DR development and future market design is not an ‘either-or’ proposition
- Market design initiatives aimed at dispatchable generation (e.g DRRS, firming) continue to move forward
- Significant future growth warrants considering an ‘all of the above’ approach to meet ERCOT reliability mandate
- Program approach is meant to address barriers unique to residential DR
  - Wholesale-Retail disconnect
  - Lack of scale
  - Highly weather-dependent
  - Customer fatigue and inherent switching risk (in competitive areas)
  - Underutilization: 50,000 registered out of ~**7**million residential customers in competitive areas
- Implementation of proposed cap to (discussed in future slides) to help manage wholesale market concerns with further study of whether/how response can be integrated into future program evolution

Proposed Updates and Refinements

Design Issues

- Incentive payment considerations
- Program cost
- Cost recovery
- Eligibility
- NOIE participation
- Minimum size
- Program trigger

Incentive Payment Discussion

- Next slides will provide additional clarity around the incentive payment, some unique considerations applicable to residential DR and a proposal to provide more predictability on the cost of the program

Incentive Payment Discussion

- As proposed at first workshop:

$$\frac{X}{No.\,of\ events/year} \times \sum_{1}^{No.\,of\ events/season} DR\ Performance$$

- Where x = lesser of CONE ($140/KW-Year) and historical 3-year rolling average Peaker Net Margin (PNM)

Incentive Payment Considerations

- Different perspectives on whether payment was too high or not high enough
- Incentive payments are for residential baselined demand response (KWhs not MWhs)
- The high x of y net load hours are not known in advance, day-ahead, nor in real-time
  - Only known after-the-fact
- Residential households who participate will need to be curtailed for multiple days and hours
  - **None of the hours outside of the high x of y will be compensated**
- Net load times are likely later or earlier than "traditional" summer DR.

Predicting Net Load -2023 example

Summer 2023 had 49 days with a peak higher than 80 GW (the previous all-time peak demand). These would need to be considered as potential ‘x of y days’

Days Over 80 GW Peak			
Month	2021	2022	2023
June	0	0	4
July	0	1	15
August	0	0	26
September*	0	0	4

Actual v Effective payment

- Compensation is only for the x of y hours
- In 2023, some REPs deployed 30 times during the summer
- This makes the effective payment **much lower** (~$1-$2 per event assuming a 1kwh reduction)
- This would be reduced further accounting for administration costs and if the REP/NOIE had to include additional households to avoid response fatigue, opt-out (add the too low consideration)

Program Cost Management

- While growing DR is a key objective, some degree of management is warranted both for predictability and for considerations around settlement and credit

Design Proposal: Seasonal MW Cap

- For discussion, ERCOT has evaluated the addition of a MW cap on participation
- Any cap should be able to support growing participation and ensure a degree of predictability around cost

Design Proposal: Seasonal MW Cap Example

- 500 MW seasonal compensation cap –calculated load reduction
  - Current number of smart devices reported at residential households in competitive areas and enrolled in REP programs ~50 MW (50,000 households assuming 1kw of response); ~160 MW and 160,000 households in NOIE areas.
  - 500 MW would allow for significant increase in participation
- If 500 MW cap is exceeded in any season, baselined DR amounts in each REP and NOIE area would be reduced pro-rata by the fraction exceeded
- E.g. if 500 MW cap was exceeded by 10% in a season, baselined calculations in all participating areas would be reduced by 10%
  - No change to incentive payment, only adjustments to kwh amounts

ERCOT is interested in stakeholder feedback around the concept of a cap

Cost Recovery

- ERCOT believes that costs should be recovered on the basis of seasonal load ratio share
- While incentive payments are based on performance, the benefits are system-wide
- Goal is to make program available to all REPs and NOIEs
- Next slide illustrates settlement/cost impact based on a 500 MW cap

	500 MW Cap	
Demand Response Scenarios (average MW per response)		500
Price Paid for Response		
CONE ($/KW-Year)	$	140.00
Hourly Response Price ($/KWh)	$	17.50
Hourly Response Price ($/MWh)	$	17,500.00
Effective Price Paid for Response		
Response Factor (nb. hours of response needed to hit target hour)		8
Effective Response Price ($/KWh)	$	2.19
Effective Response Price ($/MWh)	$	2,187.50
Total Payments for Program		
Annual MWh Response (MWh)		4,000
Annual Payments ($)	$	70,000,000
Annual Payment to Consumer with 1KW Response ($)	$	140
Annual Uplift Costs*		
Annual Uplift to Load $/MWh	$	0.152
Annual Uplift to Load $/KWh	$	0.00015
Annualized monthly cost to 1200KWh consumer	**$**	**0.18**
Seasonal Ratio Share Uplift Costs*		
Winter Uplift to Load $/MWh	$	0.2562
Spring Uplift to Load $/MWh	$	0.0825
Summer Uplift to Load $/MWh	$	0.1460
Fall Uplift to Load $/MWh	$	0.1196
* Load values are December 2023 - November 2024		

Load (MWh)	
461,466,268	
Load (MWh)	Hours in Season
102,468,632	3
106,015,388	1
179,793,804	3
73,188,442	1

Eligibility

- Participation in the program will be at the REP/NOIE/LSE QSE
- Third parties will have the opportunity to participate indirectly by partnering with individual REPs and NOIEs
- Direct third-party participation introduces additional complexity related to administration, customer protection and tracking (ex. two entities representing the same ESIID), unintended consequences (‘snapback’) that is beyond the scope of the program as proposed

NOIE Participation

- On May 16, ERCOT held a dedicated workshop to discuss issues particular to the participation of NOIEs in the program
  - Eligibility
  - Data submission and verification

NOIE Eligibility

- PUCT substantive rule 25.186 does not apply to NOIEs
- Restrictions on participation in other ERCOT programs and pilots will be maintained
  - May consider opportunities to refine this in future design evolution
- Concern expressed by NOIEs about being able to participate in this program and also being able to utilize DR for internal purposes.

NOIE Submission Requirements

- Original proposal was to require NOIEs to submit all residential customer data (for matching sites baseline methodology)
  - Attribute data: zipcode, electric space heating, electric water heating, PV, other DG, EV, Pool, Battery
  - Other DR participation (behavioral, peak rebate, etc)
  - 15-minute premise-level Interval data
- The ‘all’ or 100% of residential meter data requirement may not be realistic nor is it necessary to perform matching sites baseline
  - 15-minute premise-level data for all **premises participating in the program** is required
  - 100% of total residential customer data at 15-minute premise-level not required but need enough data to allow for matching baseline (can be reviewed case-by-case)

NOIE Submission Requirements

- Set up non-settlement ESIIDs (similar to Load Resources) for all participating NOIE residential customers
- Data would be used for Residential participation/event reporting for Annual DR Survey

Minimum Size

- At very low levels of participation, baseline errors are problematic for baseline accuracy.
- Proposed minimum required participation level: **2,000 households**

Program Trigger

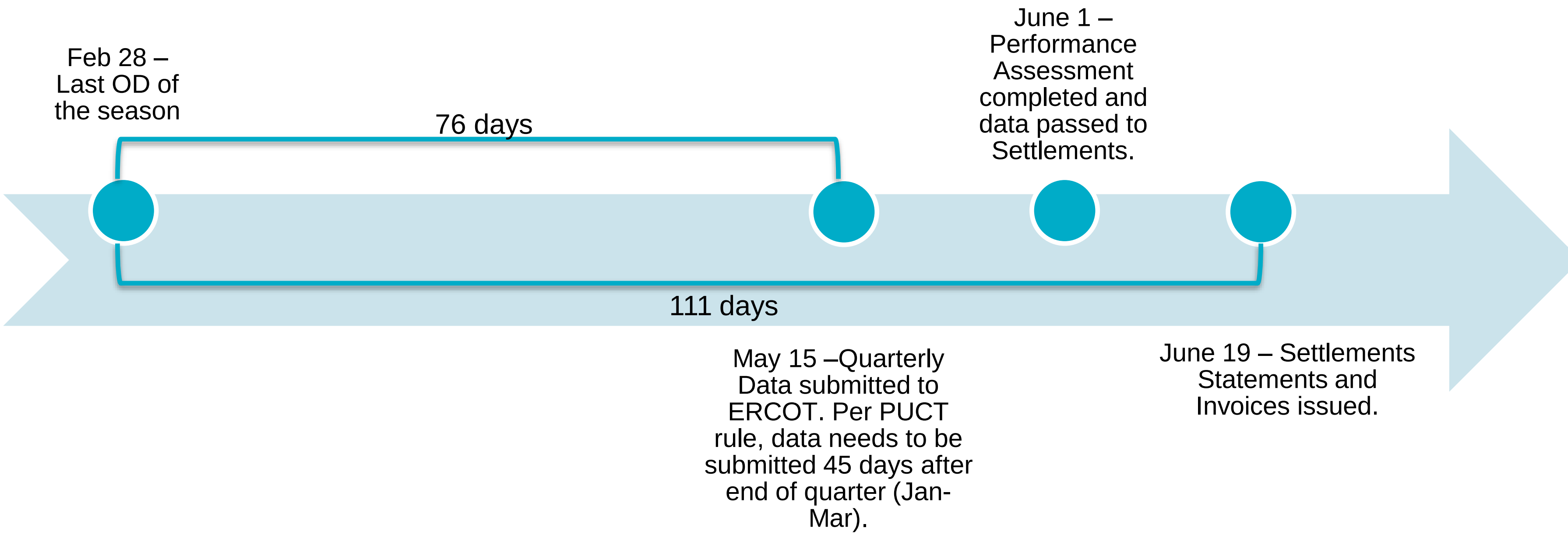
- ERCOT is proposing that *actual* net load be the basis for x of y determinations
- Inherent challenges with predicting net load are reflected in the proposed incentive payment for successful load reductions

Settlement and Credit

Settlements

- ERCOT is proposing that the costs for the residential demand response program be uplifted on a seasonal load ratio share basis.
- Settle in a similar fashion as Emergency Response Service (ERS) by including demand response payments and charges on Real-Time Settlement Statements and Invoices
- The data submission for these options would follow the quarterly data submission timelines for the Responsive Device Program implemented in 16 Texas Administrative Code § 25.186.

Settlement Timeline: Dec-Feb Winter Season



Will be included on the Final Statement that is posted approximately 35 days after ERCOT receives data from the TDSP. Resettled on the True-Up Statement for that same OD. This is a similar approach as ERS. Post Date: 06/19/2025 and 10/22/2025 for OD: 04/25/2025

Credit

- Should ERCOT collateralize the estimated exposure of the uplift amounts before the season?
  – Payments for the program are “pay for performance” only. With no penalties for non-performance, there is no need to collateralize participants in the residential demand response program. Collateralization would apply to the uplifted amounts only.
  – The mechanisms of payment and charges for the residential demand response program are similar to ERS, for which ERCOT does not require collateral in advance. ERCOT only collateralizes ERS once the invoices are issued (due in 2 days).
  – If the size of the program is less than $75M annually, ERCOT is currently thinking collateral in advance is not necessary.
  – For comparison purposes, annual payments for ERS have been approximately $50M - $70M.

Credit Options

- *If* collateralization in advance is required:
  - ERCOT would estimate the unbilled seasonal uplift for load (covering estimated amounts for 2 seasons due to the length of the settlement cycle) and include that amount in the Estimated Aggregate Liability (EAL) prior to the start of the season.
  - Once the invoice is issued for a season the estimated amount would be reduced to 1 season to avoid double counting with the increase in EAL due to the issuance of the invoice. After the due date the estimated amount will be brought back to 2 seasons worth of estimated invoices.

Analysis and Data Requests

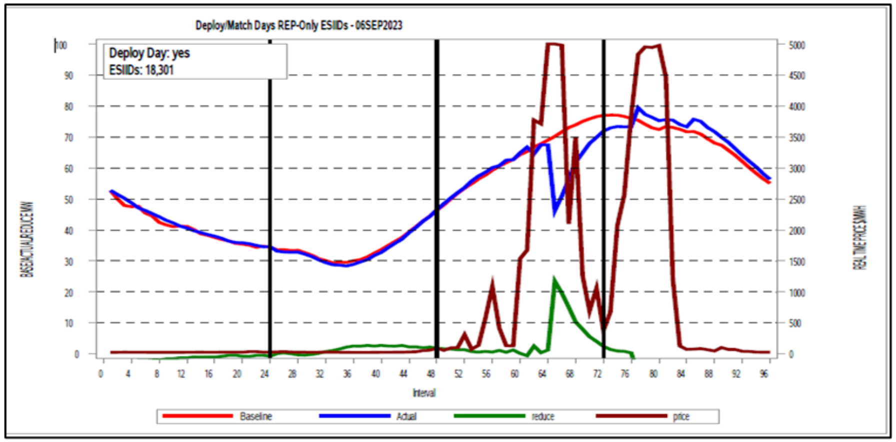
37

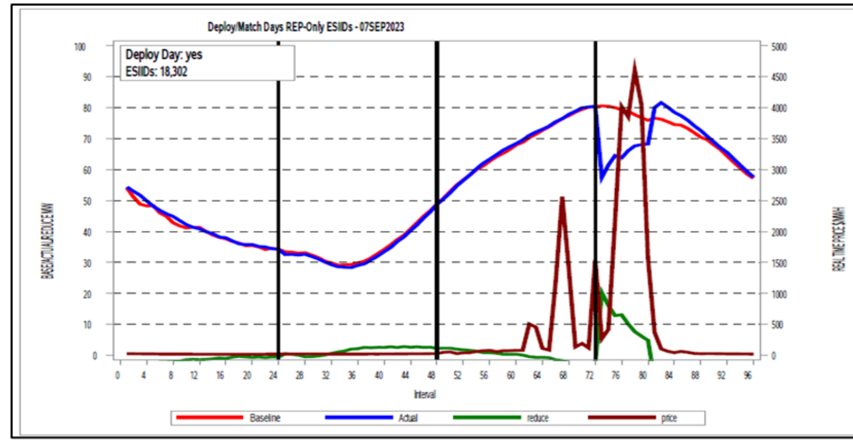
Matching Sites Method

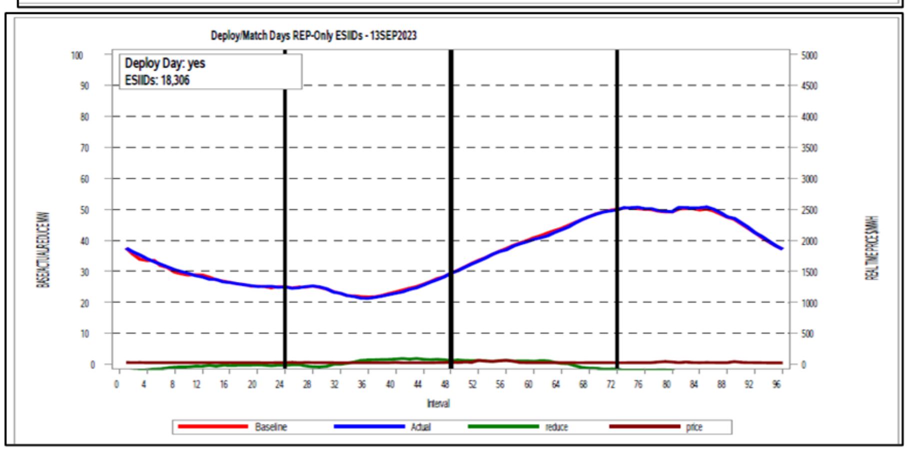
- Match deployed ESI IDs with non-participating (all programs) ESI IDs on selected attributes and usage patterns.
- Attributes: TDSP Code, Profile-Type Code (RESHI, RESLO), On-site gen (PV,WD,DG), Weather Zone, Zipcode, Substation Code
- Usage pattern: 12 two-hour demand values on non-deploy days.
- Matched sites selected based on lowest ssq-diffs … closest 5 sites with higher use and closest 5 sites with lower use.
- Interval-by-interval average of the matched sites load is the baseline including day-of-adjustment factor.
- Export from matched sites with on-site generation is used as baseline for exports.

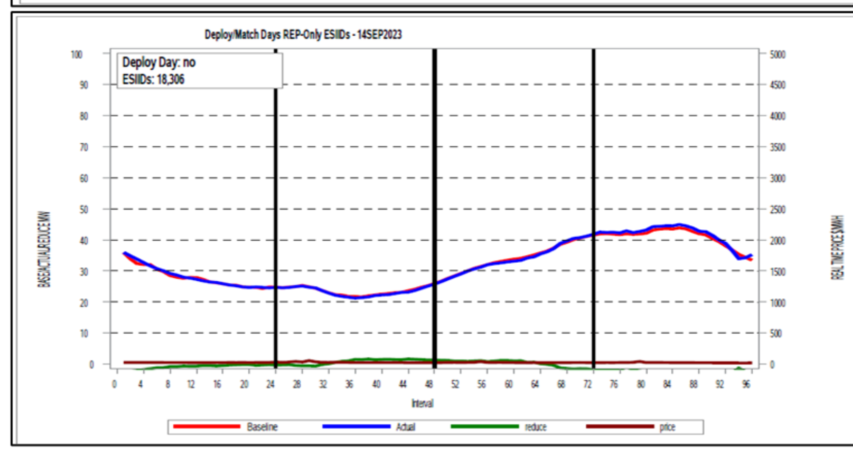
Matching Sites Baseline Examples

Deploy Days vs Non-Deploy Days









Historical Data

The following data was requested following the first Residential DR Workshop and is available as a separate attachment (for Winter 2023 – Spring 2025)

•Item 1: Highest Net Load per Season
•Item 2: PRC Lowest 10 per season
•Item 3: RTOLCAP Lowest 10 per Season

The data was compiled based on the following criteria:

1.Identified the 5 peak net load hours for **summer** and **winter**, and 2 peak net load hours for **spring** and **fall**, using net load.

2.For each of those peak net load hours, the following data is included:

- **Load** → Load
- **Wind output** → WindGen
- **Solar output** → SolarGen
- **LZ prices** → LZHoustonSPP, LZNorthSPP, LZSouthSPP, LZWestSPP
- **Online ORDC Adder price** → OnlineORDCAdderPrice
- **PRC** → PRC
- **ORDC online and offline reserves** → ORDCOnlineReserves, ORDCOfflineReserves

3.For the 10 hours in each season with the lowest **PRC** (PRC), the same data fields listed above are included.

4.For the 10 hours in each season with the lowest **ORDC online reserves** (ORDCOnlineReserves), the same data fields are also included.

Next Steps

- Any additional feedback or questions based on proposed refinements can be submitted to ryan.king@ercot.com and Mohamed.elmadhoun@ercot.com
  - Please aim to provide feedback by **Friday July 11**
- Individual meetings also welcome
- ERCOT appreciates the feedback received to date and will continue to review and refine design issues with the goal of bringing forward an NPRR in August