growth have become increasingly misaligned with the existing load zone map. The Permian Basin, a major hub for oil and gas production, has emerged as a high-cost load pocket. In contrast, the Texas Panhandle often sees negative prices due to frequent curtailment of abundant wind generation. Placing both of these regions within the same load zone (West) leads to inefficient pricing that fails to reflect the underlying differences in system conditions.

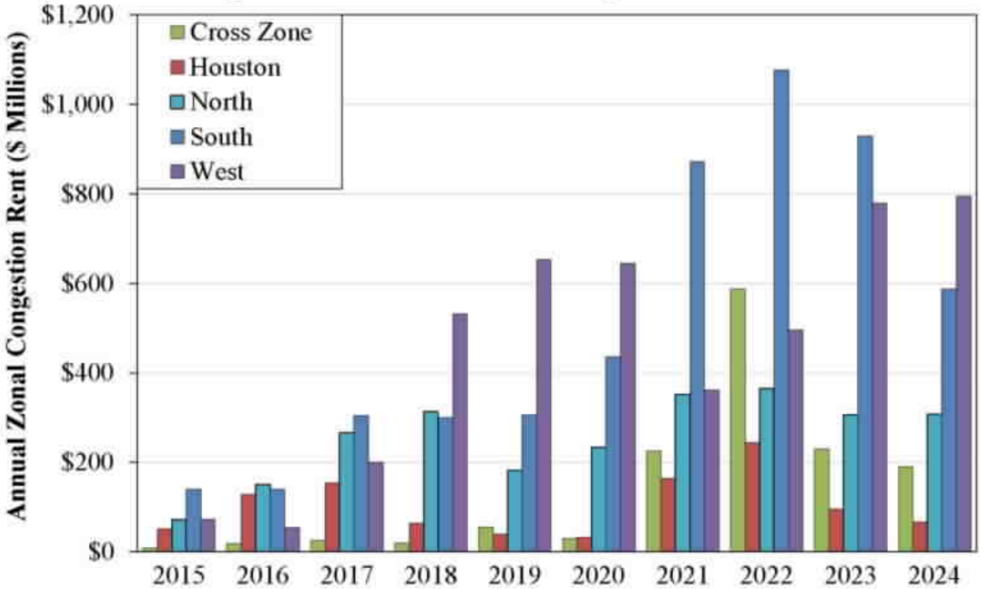
Other upcoming policy changes also highlight the growing need for load zone pricing that reflects the actual cost of serving load within each zone. For example, with the approval of NPRR 1188 in November 2024, Controllable Load Resources (CLRs) will be shifted from zonal to nodal pricing, removing their nodal prices from the Load Zone (LZ) price calculations. This policy will incentivize CLRs to site at lower priced nodes, thus removing those lower priced nodes from the calculation of the load zone price, resulting in higher load zone prices. For some customers, such as inflexible oil and gas load in the Permian Basin, higher prices resulting from load zone reconfiguration will more accurately reflect their true cost of service. However, for consumers in the Panhandle who lack the flexibility to qualify as CLRs, the exodus of more flexible load from the zone will only widen the gap between the prices they are charged and the actual cost of serving them. This highlights the need for careful design of load zones to ensure that price signals align with cost causation across all types of customers.

This section introduces a methodology for re-defining the load zones according to geographic proximity and historical nodal prices. We then present an analysis of how the implementation of these updated load zones would impact congestion management and zonal pricing outcomes.

### 1. Congestion Impact

The four current load zones within ERCOT were established in 2003 and comprise the North, West, South, and Houston load zones. These load zones no longer effectively represent the dynamics of Texas's electricity market and result in high rates of intra-zonal congestion, particularly in the South and West Zones, as shown in Figure 47.

**Figure 47: Annual Zonal Congestion Rent**



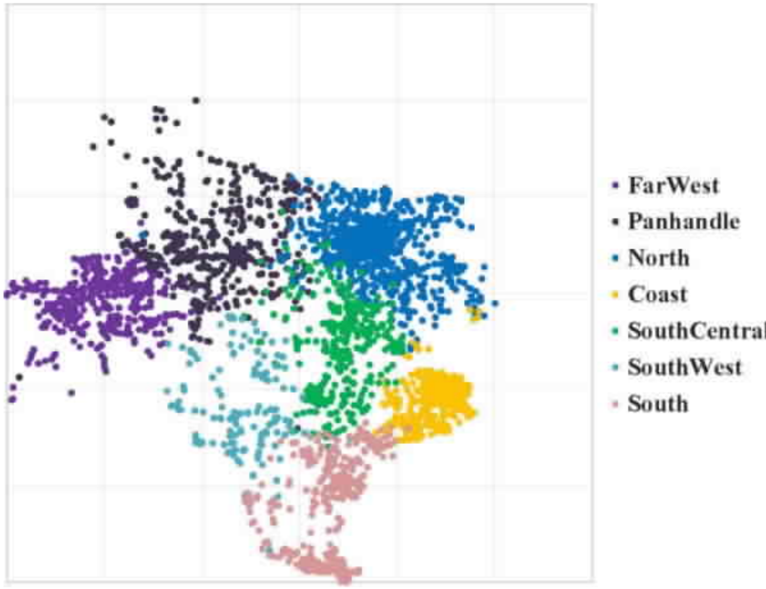

This intra-zonal congestion represents a growing difference in the cost of service within the load zones that should be reflected in the prices paid by load. To address this issue, the IMM recommended in the 2020 SOM report that ERCOT should reconfigure the load zones to better reflect the topology of the network. Next, we discuss a methodology for defining the boundaries of the load zones based on geographic coordinates and historical pricing outcomes.

### 2. Methodology for Defining Load Zones

The methodology groups substation-level load nodes into new load zones based on geographic coordinates and historical price data.[39] These metrics were chosen to define load zones according to proximity and congestion conditions. Our analysis evaluated configurations of six, seven, and eight load zones, spanning from January 2021 to December 2024. Figure 48 illustrates the resulting distribution of load nodes within the proposed seven-load-zone configuration.

39 The methodology uses k-means clustering refers to a machine learning algorithm used to group data into clusters based on their similarities. This algorithm incorporates geographic proximity, congestion data, and a specified number of load zones to arrive at a grouping of substations into a new set of load zones.

**Figure 48: Geographic Distribution of Substations for the 7-Load-Zone Configuration**




To evaluate the improvement in zonal pricing achieved by this updated load zone configuration, we consider the resulting decrease in intra-zonal congestion rent, as shown in Table 5. This data indicates that such a reconfiguration would result in a significant reduction in intra-zonal congestion compared to the current load zone map. This reconfiguration also produces more congestion rent between zones, the result of price disparities that efficiently reflect the geographic differences in the cost of serving loads in different parts of the grid.

**Table 5: Real-Time Congestion Rent ($MM) for the 7-Load-Zone Configuration**

| | Cross Zone | Coast | North | South | SouthCentral | SouthWest | FarWest | Panhandle |
|---|---|---|---|---|---|---|---|---|
| | $ Millions | | | | | | | |
| **2021** | $821.6 | $304.5 | $208.8 | $214.9 | $90.9 | $78.6 | $90.3 | $223.7 |
| **2022** | $1,454.4 | $387.8 | $185.2 | $268.3 | $49.3 | $122.2 | $119.3 | $187.7 |
| **2023** | $1,176.2 | $230.8 | $151.5 | $171.3 | $122.9 | $142.2 | $59.9 | $280.3 |
| **2024** | $853.2 | $100.5 | $105.4 | $215.6 | $180.8 | $85.6 | $164.7 | $254.5 |

For more detail on these disparities, Figure 49 and Figure 50 compare pricing for the West and South Load Zones to the prices corresponding to our proposed configuration of seven load zones.

**Figure 49: Comparison of LZ West Prices: Current vs. New 7-Load-Zone Configuration**

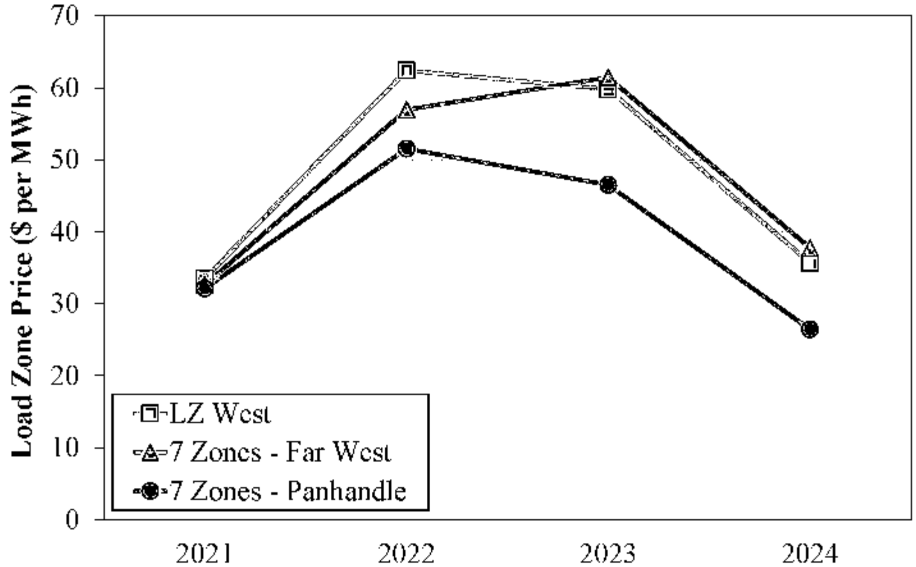



**Figure 50: Comparison of LZ South Prices: Current vs. New 7-Load-Zone Configuration**

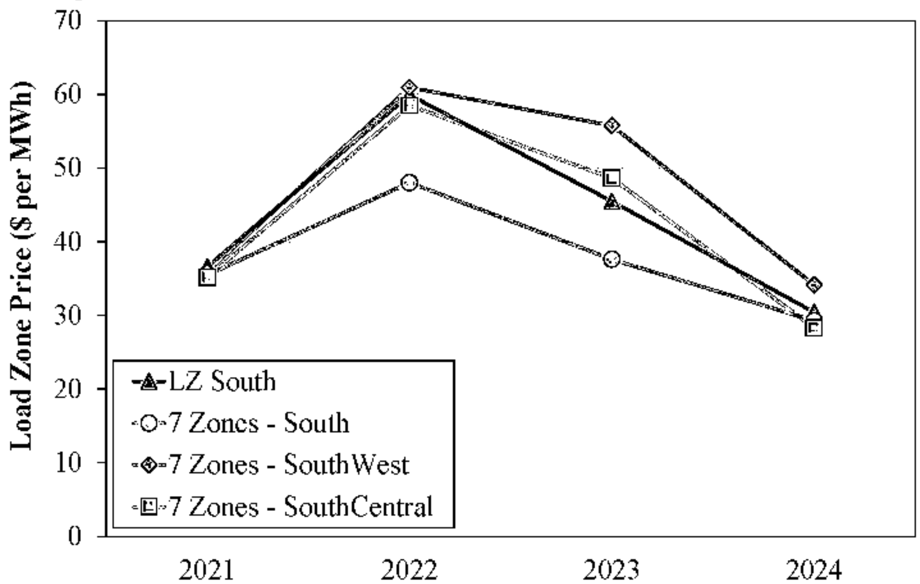



Figure 49 shows a significant difference in pricing between the Panhandle and Far West, which approximately corresponds to the Permian Basin. Similarly, Figure 50 shows large differences in pricing between a new "7-South" load zone that goes from Corpus Christi to the Rio Grande Valley and the new SouthWest and SouthCentral zones. These large differences in pricing between regions included in the same load zone indicate that the current load zones are obscuring large differences in the cost of serving load within the same zone.

This analysis supports our recommendation that ERCOT develop a process for re-defining the load zones on some basis so that they better reflect the current congestion conditions on the grid. Given that CRR auctions are conducted as far as three years into the future, any changes to the definitions of the load zones would likely have to be set at least three years in advance so that market participants have sufficient time to factor any changes into their CRR positions. Additional detail related to this analysis can be found in our presentation to the Congestion Management Working Group (CMWG) in July 2024.[40]

[40] https://www.ercot.com/files/docs/2024/07/10/Updating-ERCOT-Load-Zones-CMWG-July-2024.pptx

# V. MARKET OPERATIONS

Ideally, markets should procure and utilize all of the resources necessary to reliably operate the system. In reality, the market schedules and instructions are often supplemented by out-of-market actions by the operators to address operational issues. Out-of-market actions are undesirable because they interfere with the price signals that drive efficient short-term behavior and long-term investment decisions in a competitive electricity market. These actions can also lead to cost shifts between market participants, reduce transparency, and complicate market settlements. While sometimes necessary for reliability, frequent reliance on out-of-market actions suggests a misalignment between the market requirements and the operational needs of the system. This chapter focuses on these types of out-of-market operator actions.

## A. Reliability Unit Commitments

### 1. Unit Commitment under the Multi-Settlement Market

Shortfalls in market-procured capacity can arise from how generators participate in the market. The majority of generators in ERCOT decide on their own whether to start up, a practice known as self-commitment seen in Figure 30. This approach contrasts with other Independent System Operators (ISOs) or Regional Transmission Organizations (RTOs) where a much larger share of the generation is scheduled through the day-ahead markets.

ERCOT's day-ahead market is financially binding and does not result in physical obligations in real time. In other words, a generator scheduled in the day-ahead market is not required to generate electricity in real-time – it has the option of not running and buying back the day-head schedule at the real-time price. Conversely, if it delivers more than its day-ahead award, it is paid the real-time price for the generation in excess of its day-ahead schedule. This multi-settlement system aligns participants economic incentives to be available with the operational needs of the system. Nonetheless, if ERCOT projects that insufficient generation will be available in real-time, it may issue an out-of-market commitment instruction through the Reliability Unit Commitment (RUC) process that is described below.

### 2. RUC Fundamentals

ERCOT can commit additional generators that were not either self-committed or scheduled day ahead through the RUC process. RUC commitments can occur either in the day-ahead timeframe, known as Day-Ahead RUC (DRUC) or closer to real time through Hourly RUC (HRUC). The vast majority of RUC instructions come out of the HRUC process. For resources that submitted a valid three-part offer in the day-ahead market, RUC uses these offers. For all other resources, RUC uses either verifiable cost data or, in the absence of verifiable cost data, generic cost data associated with different classes of resources.

RUC commitments increase the supply of generation in the market, placing downward pressure on prices. To reduce this price distortion, ERCOT uses the Reliability Deployment Price Adder (RDPA), which adjusts real-time prices upward to account for the additional supply injected by RUC, thereby preserving shortage signals that would have existed without the out-of-market commitment. It also applies an offer floor of $250 per MWh for RUC-committed units. By setting a high minimum-offer price for these resources, ERCOT reduces the likelihood that they will be economically dispatched or set the market clearing price, limiting their direct influence on real-time prices. Together, these tools help limit the extent to which RUC suppresses prices.

Operators issue RUC commitments to meet forecasted system-wide demand or to manage congestion. In the latter case, specific units may be required to serve load in transmission-constrained areas, to provide counterflow on a constraint, or support local reliability. The criteria for making RUC commitments should be transparent and grounded in objective reliability risks rather than driven by an arbitrarily conservative operational approach. Risk-based standards help ensure that the RUC process is used only when necessary, which supports market efficiency, and to maintain stakeholder confidence in ERCOT's operational decisions.

### 3. Make-Whole Payments and Clawbacks

As discussed in the previous section, generator operating costs are incorporated into the RUC process, either through three-part offers, verifiable costs, or generic costs inputs by resource type. When a generator is committed through RUC based on these costs, ERCOT uses the cost data to determine whether the unit is entitled to a make-whole payment. These payments ensure that RUC-committed units are not financially harmed when their market revenues fall short of their costs. Conversely, if a RUC-committed unit earns more revenue than its costs, ERCOT may apply a clawback to recover some or all of the excess revenues, depending on whether a valid three-part offer was submitted in the day-ahead market.

The cost of make-whole payments is allocated to two groups. First, Qualified Scheduling Entities (QSEs) that do not provide enough capacity to cover their real-time obligations are considered capacity short and bear a portion of the cost. Second, all QSEs share the remaining costs on a load-ratio-share basis. Suppliers also have the option to opt-out of both the make-whole payment and any associated clawback, which effectively means self-scheduling the unit and accepting full exposure to market outcomes. This approach gives suppliers the flexibility to manage their own risk while helping ERCOT maintain system reliability.

Prior to 2024, RUC-committed resources that had submitted valid day-ahead offers were subject to only a 50% clawback of revenues above their costs. This partial clawback created a financial incentive for some units to avoid self-committing, even when they were likely to be economic,[41]

[41] It is notable that there is no requirement that the day-ahead market energy offer that triggers the reduced claw-back percentage be feasible, i.e., able to be awarded by the day-ahead market engine based on resource temporal constraints.

in order to benefit from the opportunity to recover all costs and retain half of any upside through RUC.[42] In response to concerns that this undermined efficient market behavior, consumer stakeholder representatives filed NPRR 1172, *Fuel Adder Definition, Mitigated Offer Caps, and RUC Clawback*, in April 2023.[43] The proposal called for 100 percent clawback of revenues above cost for economic resources that were RUC-committed after submitting day-ahead offers. The PUCT approved NPRR 1172 and it took effect on March 1, 2024.

Since the implementation of this rule change, patterns in RUC clawback and make-whole payments have shifted. As shown in Table 6, clawback payments increased while make-whole payments declined in 2024. This increase in clawbacks was largely driven by a high number of unit hours in March and April of 2024 during which RUC-committed resources did not opt out of RUC settlement. We discuss these behaviors and additional RUC trends next.

**Table 6: RUC Settlement Quantities, 2020-2024**

| | Claw-Back ($MM) | Make-Whole ($MM) |
|---|---|---|
| **2020** | $0.48 | $0.40 |
| **2021** | $3.09 | $5.38 |
| **2022** | $23.74 | $42.78 |
| **2023** | $3.07 | $3.63 |
| **2024** | $7.41 | $2.69 |

### 4. RUC Trends

We now examine several recent trends related to the frequency of RUCs, the reasons RUCs were issued, and generator opt-out behavior. These trends are summarized in Table 7.

**Table 7: Reasons for RUC, 2020-2024**

| Year | # of RUC-Resource hours | | % of RUC-Resource hours | |
|---|---|---|---|---|
| | Congestion | Capacity | Congestion | Capacity |
| **2020** | 224 | - | 100% | - |
| **2021** | 810 | 3,242 | 20% | 80% |
| **2022** | 1079 | 7,166 | 13% | 87% |
| **2023** | 295 | 2,439 | 11% | 89% |
| **2024** | 738 | 1,237 | 37% | 63% |

42 The IMM recommended that ERCOT eliminate the 50% claw-back for day-ahead offers and implement a 100% claw-back for economic RUC resources in its 2022 State of the Market Report (see Recommendation 2022-2) and filed comments supporting NPRR 1172.

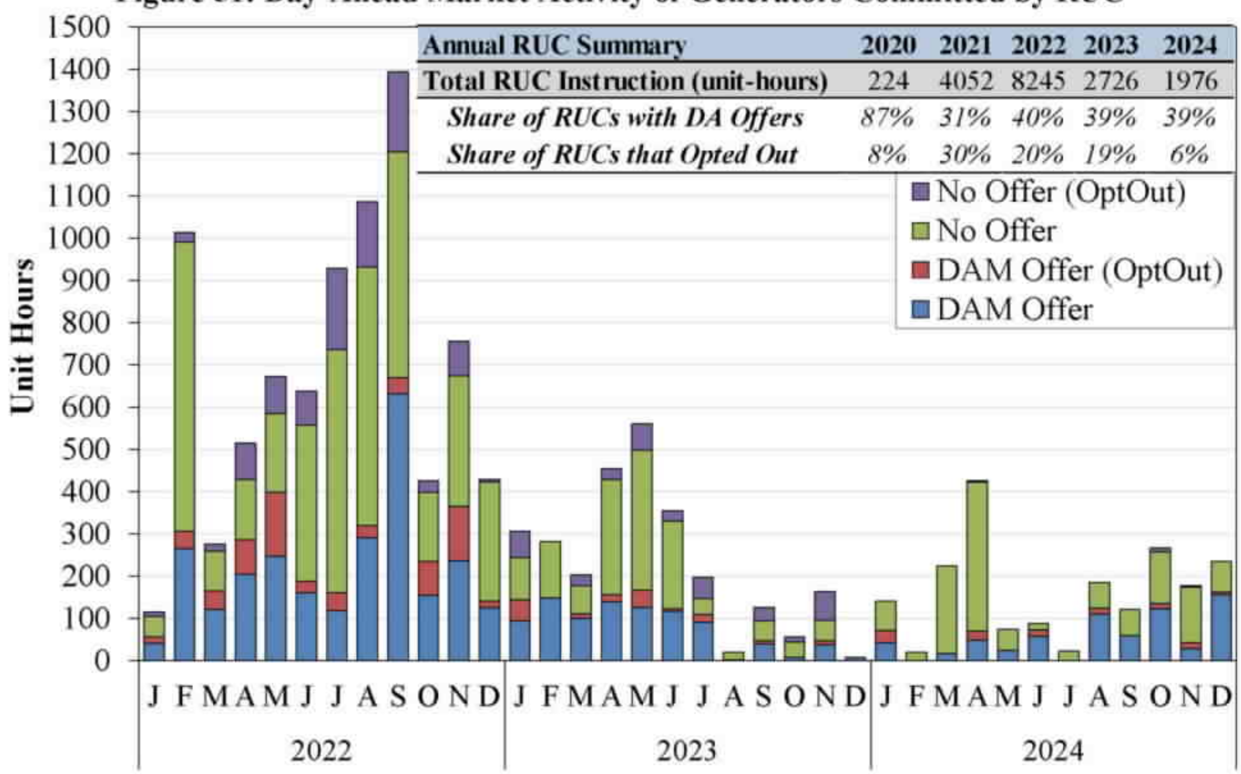
43 NPRR 1172, *Fuel Adder Definition, Mitigated offer Caps, and RUC Clawback*, available at: https://www.ercot.com/mktrules/issues/NPRR1172.

Prior to 2021, ERCOT introduced process improvements that significantly reduced the frequency of RUC commitments and most RUCs before this time were issued to manage transmission congestion. This pattern shifted abruptly in June 2021, when ERCOT adopted a more conservative operational approach. Under this new posture, ERCOT began committing additional generation resources and doing so earlier in the operating day. As a result, RUC activity increased sharply from mid-2021 through mid-2023, with most of the new commitments driven by system-wide capacity needs rather than local congestion management.

Figure 51 shows monthly RUC activity over the past three years and distinguishes between units that submitted day-ahead offers and those that opted out of RUC settlement. From 2021 through the first half of 2023, RUC activity was elevated as ERCOT maintained a conservative operational approach. This was followed by a notable decline in RUC commitments during the second half of 2023. The decline was driven, at least in part, by higher energy and operating reserve prices following the implementation of ERCOT Contingency Reserve Service (ECRS), which encouraged more self-commitments.

In 2024, RUC activity remained below earlier levels but increased slightly compared to late 2023. This rebound coincided with the addition of substantial new solar capacity, which contributed to lower prices and reduced self-commitment from thermal units. In some cases, over-forecasting of solar generation may have led to concerns about real-time capacity, prompting ERCOT to issue more RUC commitments.

**Figure 51: Day-Ahead Market Activity of Generators Committed by RUC**



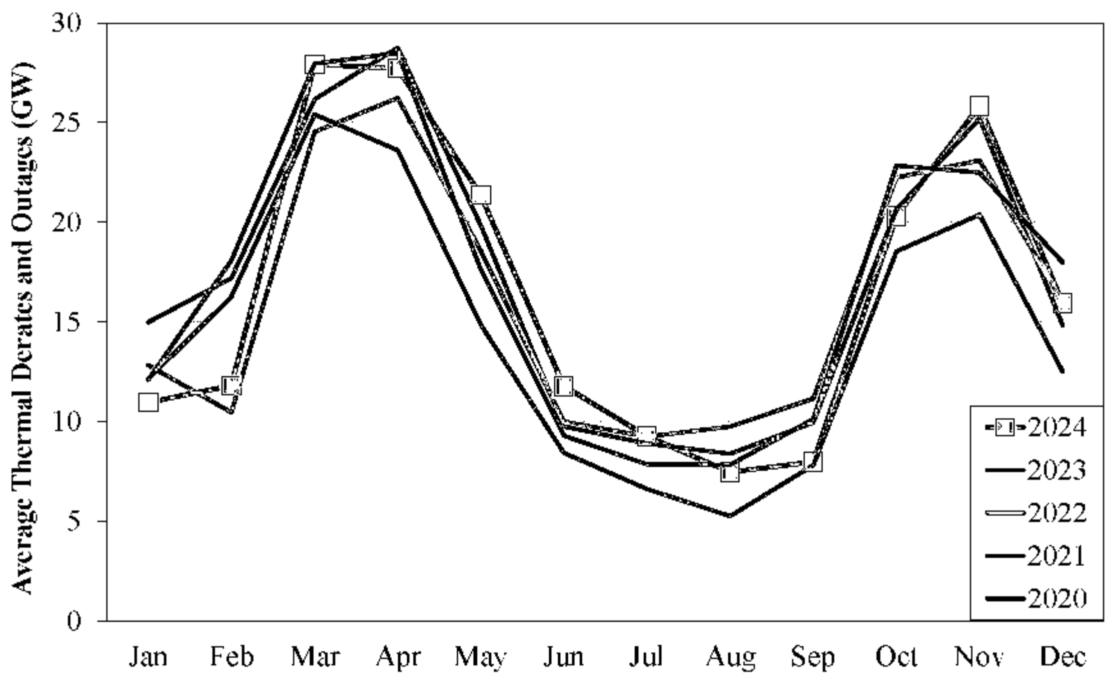
In 2020, 87% of RUC-committed units had submitted valid three-part offers in the day-ahead market. Starting in 2021, this percentage dropped significantly to between 31% and 40%, where it remained through 2024. This shift coincided with increased use of RUC following ERCOT's adoption of a more conservative operational posture. During the early part of this period, a higher share of RUC-committed units also opted out of RUC settlement, which reduced the number of units eligible for make-whole payments or subject to claw-backs. By 2024, only 11% of RUC-committed units opted out of settlement, returning closer to pre-2021 levels. This shift is likely another consequence of NPRR 1172.

## B. Thermal Generation Outages and Deratings

At any given time, some portion of ERCOT's generation is unavailable because of outages and deratings. Derated capacity is the difference between the registered summer maximum capacity of a resource and its actual capability. It is common for generating capacity to be partially derated because the resource cannot achieve its installed capacity level due to technical or environmental factors (e.g., equipment failures or ambient temperatures).

Outages and deratings of thermal power plants are especially important because they can affect reliability during periods when other resources are limited. As ERCOT has become more reliant on wind and solar, overall generating capacity has grown more sensitive to weather conditions. During times of high demand with low renewable output, thermal units often become essential for meeting system needs. However, thermal generators tend to schedule more of their outages in the spring and fall, when demand and prices are typically lower. Figure 52 illustrates this seasonal pattern.

**Figure 52: Thermal Hourly Average Outages and Derates by Month**

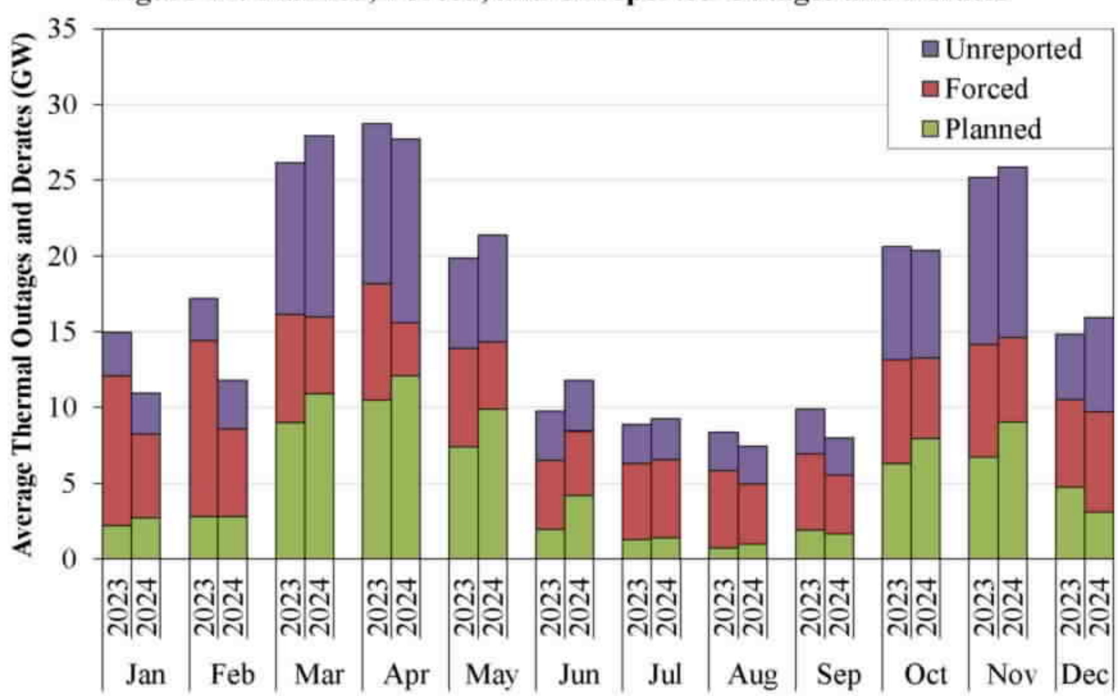


Outages and derates introduce uncertainty for ERCOT operators and market participants by complicating real-time assessments of supply and pricing. To help system operators to manage this dynamic, generators are expected to schedule planned outages in advance, giving visibility into unavailable capacity. However, planned outages account for only part of the total. Many outages are forced, resulting from unexpected failures that take units offline. While most forced outages are eventually reported, a large number remain unreported, making it harder for ERCOT to plan and operate the system reliably. Strengthening outage and derate reporting requirements would help improve system coordination and transparency.

Figure 53 presents monthly totals of planned, forced, and unreported outages and derates of thermal resources for 2023 and 2024. For records in the outage scheduler occurring less than 30 days, the notification for an outage greater than 7 days to the start of the outage was considered planned, a report less than or equal to 7 days prior was considered forced. Patterns in 2024 were similar to those in 2023, with planned and unreported outages lowest during the summer, when energy is most valuable, and highest in the spring and fall, when system load and net load are typically lower. Forced outages remained relatively stable across the year. NPRR 1084, Improvements to Reporting of Resource Outages, Derates, and Startup Loading Failures, was implemented at the end of 2022 to improve outage reporting practices.[44] However,

Figure 53 indicates that a large share of outages and derates in 2024 were still not reported in the outage scheduler.

**Figure 53: Planned, Forced, and Unreported Outages and Derates**




44 https://www.ercot.com/mktrules/issues/NPRR1084

## C. QSE Operation Planning

The Current Operating Plan (COP) is the mechanism used by QSEs to communicate the expected status of the QSE's resources to ERCOT. COPs are updated on an ongoing basis by QSEs for each operating hour. The RUC process uses the schedules reported in the COP to see which resources are planning to be running each hour of the operating day. The schedule of commitments in COP along with forecasts for renewable generation are compared against forecasted load to determine if out of market commitments are necessary to manage a system-wide supply shortage or transmission constraint. Resources shown as offline in their COP are eligible for commitment through RUC subject to start-time constraints. Thus, the accuracy of COP information greatly influences ERCOT's ability to effectively commit resources through the RUC process.

To summarize the accuracy of COP statuses in situations where RUC may be needed for capacity, we considered all intervals where online reserves were less than or equal to 6,500 MW. We then compared the real-time status of all resources in SCED against their COP for the last submitted COP that would have been seen before a decision had to be made about committing a unit given their start time. For example, if a resource has a start time of six hours, we compared the real-time status of that resource against the status reported in its COP from six hours prior. Figure 54 summarizes the magnitude of disparity between real-time and COP statuses using this methodology is shown in.

**Figure 54: Difference in Real-Time vs COP Capacity, PRC ≤ 6,500 MW**

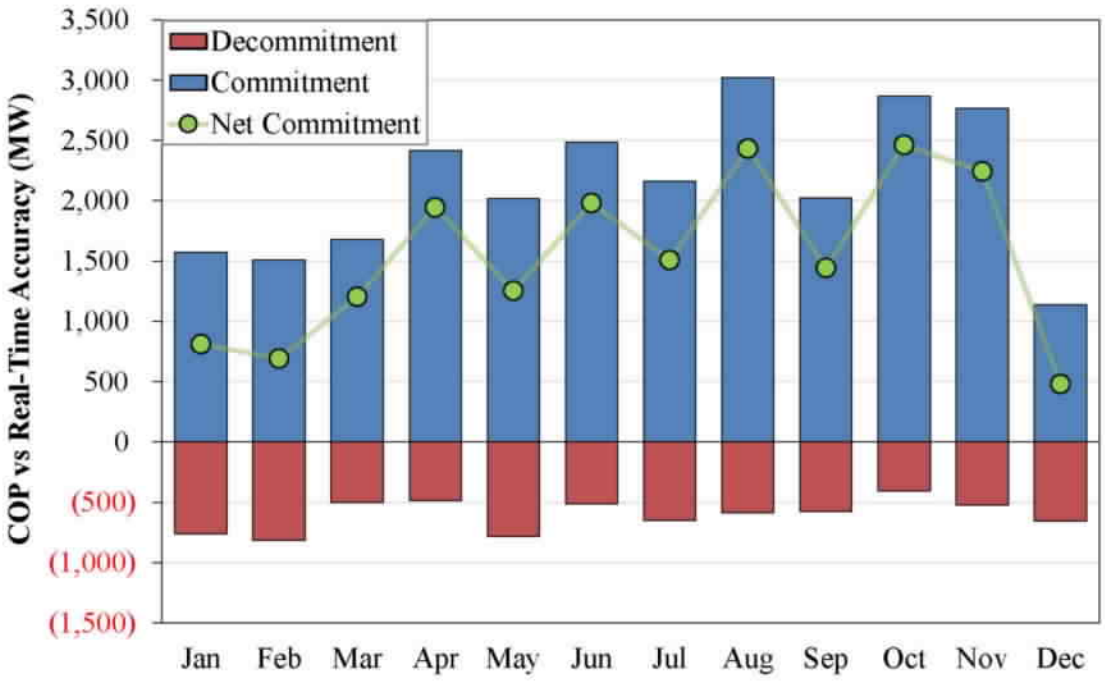



Figure 54 shows that for intervals where online reserves were less than or equal to 6,500 MW there is on average approximately 1,300 MW more capacity online in real-time than was reported in the last applicable COP, where the net difference in capacity between real-time and COP is plotted in green. The blue bars refer to capacity that was online in real-time when it was scheduled to be off in COP, and the red bars refer to capacity that was offline in real-time when it was scheduled to be on in COP.

The most noteworthy aspect of this data is that over 90% percent of the inaccuracy of net committed capacity in COP can be attributed to resources with a start time of one hour or less. Resources with longer start times tend to have more accurate COPs corresponding to intervals with relatively low levels of reserves in real-time. Thus, the magnitude of COP inaccuracy is less problematic than it may appear at first, because there is less risk in waiting until closer to real-time to commit units with shorter start times. Even after the last regular RUC run before real-time, operators can manually commit these short start-time units if necessary.

## D. Firm Fuel Supply Service

A new Firm Fuel Supply Service (FFSS) was approved and implemented in 2022, which pays a subset of dual-fuel generators to purchase fuel to be stored on site.[45] As of July 1, 2023, FFSS was expanded to also include certain gas-fired generation resources with owned natural gas stored offsite and accompanied by firm transportation and storage agreements.[46] Implementation of FFSS was part of the PUCT's Phase I Market Design effort and in response to Texas Senate Bill 3, 87th Session.

ERCOT has now issued three RFPs for FFSS, each with an obligation period beginning on November 15 and ending on March 15.[47] In 2024, FFSS was deployed across five consecutive days from January 13-17. Over that time, 10 different FFSS Resources (FFSSRs) were deployed for a maximum of 916 MW, as shown in Table 8.

**Table 8: Firm Fuel Supply Service Deployments**

| Day | Maximum Aggregate FFSS Deployment (MW) | Average RT Price | Operating Day Online Reserves Minimum |
|---|---|---|---|
| 1/13/2024 | 80 | $3.66 | 17,358 |
| 1/14/2024 | 726 | $70.78 | 12,464 |
| 1/15/2024 | 916 | $88.02 | 8,397 |
| 1/16/2024 | 916 | $148.71 | 5,414 |
| 1/17/2024 | 150 | $27.49 | 15,054 |

45 *See* https://www.ercot.com/services/programs/firmfuelsupply; NPRR 1120, *Create Firm Fuel Supply Service*, available at: https://www.ercot.com/mktrules/issues/NPRR1120.

46 NPRR 1169, Expansion of Generation Resources Qualified to Provide Firm Fuel Supply Service in Phase 2 of the Service, available at: https://www.ercot.com/mktrules/issues/NPRR1169.

47 *Wholesale Electric Market Design Implementation*, Project No. 53298, ERCOT Letter Regarding FFSS Phase I Procurement Results (Sept. 27, 2022). ERCOT Report of the Second Procurement of the Reliability Product, Firm Fuel Supply Service (FFSS) (Sept. 21, 2023).

ERCOT's FFSS Deployment Report for this event states that the decision to deploy FFSS was based on information about potential gas supply restrictions that could affect generation resources. However, if such restrictions did occur, they did not lead to a noticeable decline in operating reserves or a rise in real-time prices, as shown in Table 8. Only January 16 saw conditions tight enough to produce a significant ORDC price, reaching $88 per MWh for one SCED interval. These outcomes raise questions about whether FFSS deployments were necessary on most of the days included in this event.

The procurement and deployment of FFSS costs ERCOT consumers tens of millions of dollars per year. One factor that contributes to inefficient market outcomes and excess cost is that FFSS resources are also eligible for make-whole payments if their market revenues during a deployment are less than the cost of replacing their spent fuel. This make-whole payment diminishes the incentive for FFSS resources to offer at prices reflecting the marginal cost of replacement fuel. If FFSS resources were required to offer according to the marginal cost of fuel replacements, those resources would be dispatched at lower levels, resulting in lower make-whole payments.

Further, real-time price is distorted with FFSS deployments when the cost of the deployed assets are not accounted for in price formation. This has a price-suppressing effect for all other supply in the real-time market. Another factor is that the aggregate high sustained limit (HSL) of deployed FFSSRs is not included as online reserves in the calculation of the ORDC price adder, which results in higher shortage prices. Excluding this capacity from the calculation of the ORDC resulted in almost $7 million of additional cost for this event.

To address these issues, we proposed the following improvements that are consolidated in Recommendation 2023-4:

- ERCOT should develop clear procedures based on reliability metrics for deploying FFSS. For example, forecasted generation shortfalls or unresolvable transmission constraints caused by disruptions in the gas supply;
- Require all deployed FFSSRs to offer according to the marginal cost of replacing their spent fuel to minimize the need for make-whole payments and reduce price suppression; and
- Include FFSS capacity in the calculation of the ORDC. Removing the entire HSL of FFSSRs from RTOLCAP unreasonably increases the cost of shortage pricing relative to available capacity.

# VI. RESOURCE ADEQUACY

## A. Introduction

Ensuring resource adequacy is fundamental to the reliability and stability of the electricity market. Resource adequacy refers to the availability of sufficient generation and demand-side resources to meet expected electricity demand and ancillary services under normal and extreme conditions. A well-functioning market must send clear price signals to incentivize investment in new generation, maintenance of existing resources, and demand-side participation. Without these signals, the market risks underinvestment in critical infrastructure, leading to reliability challenges and potential supply shortages.

Generators assess resource adequacy to identify investment opportunities and the potential for higher revenues during shortage conditions. Load-Serving Entities (LSEs) and large consumers monitor adequacy to anticipate price volatility and plan strategies for cost management, such as demand response. A well-functioning market provides price signals for all participants to plan effectively, adapt to changing conditions, and ensure long-term system reliability.

The following concepts are important to understand regarding revenue sufficiency and investment in new generation:

**Cost of New Entry (CONE):** CONE represents the estimated fixed expense of building and operating a new power plant. Investors evaluate whether expected future market revenues will be sufficient to justify these costs before committing to new projects.

- **Shortage Pricing:** In electricity markets, prices rise during periods of tight supply to reflect the increased value of available generation. These price spikes create opportunities for generators to recover fixed costs and incentivize new investment. In ERCOT's energy-only market, shortage pricing serves as the primary mechanism for driving revenue and signaling investment decisions.
- **Peaker Net Margin (PNM):** PNM estimates the annual net revenue a peaking unit could have earned based on observed energy and ancillary service prices. Comparing PNM to CONE helps market participants determine whether revenues are sufficient to support new generation or if additional incentives may be needed to maintain resource adequacy.

### 1. Key Reports

ERCOT communicates expectations regarding future resource adequacy through several reports that provide market participants with insight into future conditions in different timeframes.

- The Monthly Outlook for Resource Adequacy (MORA) offers a short-term assessment of expected supply and demand conditions, highlighting potential risks in the coming months.

- The Capacity, Demand, and Reserves (CDR) report provides a 5-year forecast of load growth and generation capacity to help participants evaluate future resource adequacy.
- Complementing these reports, the Long-Term Load Forecast (LTLF) projects demand trends over a period of up to ten years, offering a broader perspective on future needs.

Together, these reports help market participants anticipate challenges, identify investment opportunities, and plan accordingly.

## 2. Resource Adequacy through Markets

The economic signals provided by the wholesale electricity markets will facilitate long-term investment and retirement decisions that maintain an economic level of capacity that is consistent with these signals. In general, there are three primary approaches to achieve adequate resources through competitive wholesale electricity markets:

1. Energy-only market – this market relies primarily on expected shortage revenues in the energy and ancillary services markets to motivate investment.
   - Pros: Provides strong performance and availability incentives. Is closely aligned with reliability.
   - Cons: Capacity levels may be less than needed to satisfy a particular reliability target, such as the "1-in-10" standard adopted by most Regional Transmission Organizations (RTOs).[48] Can produce highly volatile year-to-year costs and revenues that can be hedged by contracts.
2. Capacity market – Designed to procure a sufficient quantity of capacity to satisfy a specified reliability standard
   - Pros: Predictably generates the revenues needed, together with the energy and ancillary services net revenues, to compensate investors to build generation that will maintain this level of capacity, i.e., to cover new resources' net CONE.
   - Cons: Requires more complicated rules related to accreditation of generation and load resources. Is generally less directly aligned with specific operational reliability needs, for example Non-Spin Reserve Service (NSRS) or frequency response service. Capacity constructs procure generic capacity.
3. Capacity requirements – Some markets require LSE's to self supply or procure capacity to satisfy a specified capacity requirement. This is effectively a decentralized capacity market that operates bilaterally.
   - Pros: Increases the likelihood of satisfying the specified reliability standard.
   - Cons: Prices may not be efficient or competitive, which could raise costs compared to a centralized capacity market procurement.

[48] The 1-in-10 standard is the capacity needed to expect to shed load in one event each 10 years.

All market-based market proposals would fall within one of these three approaches. Each approach includes details that can be adjusted to achieve specific objectives. For example, capacity markets include many choices of design, including: (1) the procurement timeframe (prompt auction that run in the months before the planning year vs. forward auctions that run up to 3 years ahead), (2) resource accreditation rules, (3) capacity demand curve estimation, and (4) market power mitigation measures.

In an energy-only market, the shortage pricing will be the result of operating reserve demand curves (ORDCs) that will set prices when the market does not have sufficient resources to satisfy the full market requirements for energy and ancillary services. If the market is not sustaining sufficient resources, the economic signals can be strengthened by increasing the aggregate value implied by the ORDC. The Commission implemented such changes at the start of 2022 and they have been extremely effective in increasing the markets' shortage revenues. Note that spot market shortage pricing is an important element of market design even in instances where there is a capacity construct as well. Shortage pricing values additional supply at the marginal value it contributes to reliability and signals both performance and new investment. When a system is capacity-short (resource inadequate), spot market revenue will increase through more frequent and severe shortage pricing that can accompany shortage signals from the capacity construct.

Ultimately, the ORDC implies a "value of lost load" (VOLL), which is the value of avoiding load shedding. One key issue with satisfying the typical 1-in-10 reliability standard adopted by most of the RTOs throughout the country is that this standard implies a VOLL in excess of $200,000 per MWh. This explains why most RTOs have had to rely on capacity markets to supplement the revenues from the energy and AS markets to satisfy this standard. This also reveals why it is difficult to satisfy such a standard in an energy only market.

Other issues include the potential need to consider resource adequacy requirements for import-constrained zones, potential market power for new and existing resources when the market is relatively capacity-short, and market power mitigation and backstop procurement (in the load obligation model) when load and supply entities are not able to agree on a competitive price for existing or new build capacity.

### 3. Focus Areas of this Chapter

In the following sections, we examine the key factors influencing investment and resource adequacy in ERCOT, including:

- Analyzing the net revenues earned by various generation technologies in different locations, offering insight into how market conditions affected generator profitability;
- Evaluating CONE and market revenues to assess whether recent market revenues have been sufficient to support new investment;
- Discussing the reliability standard introduced in 2024 and its implications within ERCOT's energy-only market structure;

- Reviewing the primary reports that communicate the load and generation trends that determine ERCOT's resource adequacy, highlighting the limitations of these reports; and
- Reviewing the events that have resulted in the current load forecast process and offering our insights into the most recent data published in April 2025.

## B. Net Revenue Analysis

We calculate net revenue by subtracting a generating unit's variable production costs from its total potential revenue. In other words, net revenue represents the earnings available beyond short-run operating costs to recover fixed and capital expenses, including a return on investment. Net revenue is the key determinant of the incentive to invest because it is the earnings available to recover fixed and capital expenses, including a return on investment, after short-run operating costs are covered. In ERCOT's energy-only market, net revenues from the energy and ancillary services markets serve as the primary economic signals guiding investment and retirement decisions for generation resources. While revenues may also come from the day-ahead market or forward bilateral contracts, these ultimately reflect expectations of real-time energy and ancillary service prices. Although the net revenues presented in this report are based on historical prices, investment decisions are typically driven by expectations of future market conditions, including the potential for shortage pricing.

### 1. Peaker Net Margin and the ORDC

The peaker net margin (PNM) and shortage pricing mechanisms like the ORDC play a crucial role in shaping net revenue and investment signals in the electricity market. PNM estimates the annual net revenue a peaking unit could earn from energy and ancillary service markets, serving as a benchmark for evaluating whether market conditions support new investment. If PNM approaches or exceeds the CONE, it suggests that market revenues are sufficient to support new generation for that year. The ORDC reinforces this by raising energy prices when operating reserves fall below predefined thresholds, ensuring that generators are compensated for providing reliability during shortage conditions. The Reliability Deployment Price Adder (RDPA) also raises energy prices by accounting for grid operator actions made to maintain reliability that impact the market.

### 2. Net Revenue by Location

Figure 55 shows the net revenues at different locations for a variety of new generators. Because natural gas prices can vary widely based on location, the revenues for natural gas units are shown for the Houston zone (reflecting Katy hub prices) and the West zone (reflecting Waha hub prices).

**Figure 55: Net Revenues by Location, 2024**

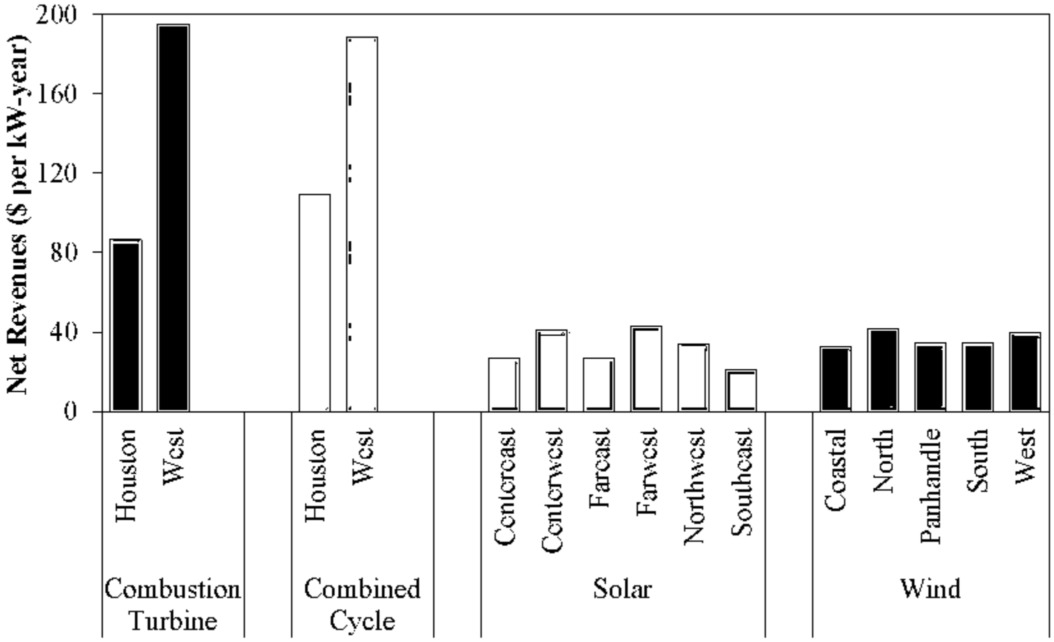



Figure 55 shows a wide gap between the net revenues in the West and Houston. Historically, high natural gas production in the Permian Basin and limited export capability have resulted in low gas prices at the Waha location and, as a result, much higher net revenues for gas resources in this area. The price gap between the two hubs widened in 2024, driven by transmission upgrades and maintenance in the West zone that substantially increased congestion costs in the region. As work on these projects concludes, we expect the gap between these two hubs to narrow again.

Figure 55 also shows the net revenues for wind and solar generation at multiple locations. The profitability of these resources is primarily driven by the amount of the local wind or solar penetration and the market prices during periods of high output. In 2024, net revenues for wind and solar were lower than those of gas-fired technologies across all areas. Additionally, the locational spread in net revenues across IRRs was smaller in 2024, due in part to more uniform weather patterns and relatively consistent congestion patterns across regions, which reduced the revenue advantages typically seen in higher-performing locations.

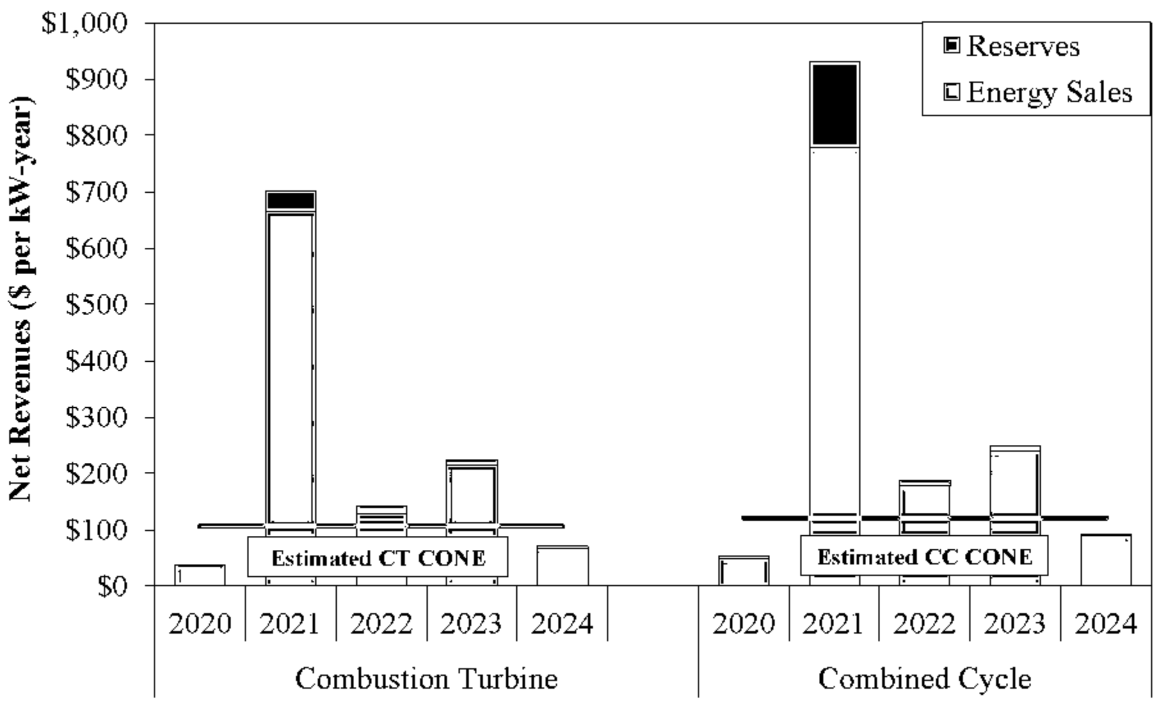
## C. Cost of New Entry and Net Revenues

CONE represents the minimum annual revenue a new generator, typically a gas-fired unit, must earn to recover both its capital and fixed operating costs over its expected lifetime. The reference technology is chosen to reflect the technology and configuration that is most likely to be built by a merchant developer in response to market price signals. Functionally, CONE serves as a levelized cost of electricity (LCOE) benchmark, capturing the amortized revenue requirement per kW for a generator to be economically viable. CONE is often framed in terms of gas generators, as they frequently serve as the marginal units in ERCOT's energy market and therefore provide a useful reference point for assessing the adequacy of market price signals to support new investment.

In practice, generator earnings fluctuate substantially from year to year, depending on system conditions and unexpected events. This can be especially true in an energy-only market. For example, the period from 2021 to 2023 reflected the latter, marked by elevated prices due to Winter Storm Uri and the inefficient procurement of the ERCOT Contingency Reserve Service (ECRS) in 2023. These years provided strong revenues for many generators, helping to offset earlier or future periods of lower earnings. However, 2024 exhibited lower net revenues as market conditions normalized and prices were more efficient.

Figure 56 presents historical net revenues available to support investment in new natural gas combustion turbines (CTs) and combined cycle (CC) generators.[49] These technologies are commonly considered the marginal new supply, meaning they are the types of units most likely to be built when the market signals a need for additional capacity. We calculate energy net revenues using generation-weighted real-time settlement point prices, assuming each unit sells energy or ancillary services in any hour it is economically profitable to do so.

**Figure 56: Combustion Turbine (CT) and Combined Cycle (CC) Net Revenues, 2020-2024**




[49] For purposes of this analysis, we used the following assumptions: heat rates of 7 MMBtu per MWh for a combined-cycle unit, 10.5 MMBtu per MWh for a gas turbine, and $4 per MWh in variable operating and maintenance costs. A total outage rate (planned and forced) of 10% was assumed for each technology. It does not include: 1) start-up and minimum energy costs; or 2) ramping restrictions that can prevent generators from profiting during brief price spikes.

The CONE values used in this report are generated by Potomac Economics using the most current data publicly available. We use data specific to the ERCOT market and also leverage observations from other RTOs in the United States. The CONE calculation, by nature of the underlying formula, is very sensitive to certain inputs outside of the direct cost of installing a new generation plant. Values for weighted average cost of capital (WACC), the discount rate used to relate future cost into current dollar values, and the period over which the financial assessment is performed all have a pronounced impact on the calculated CONE value. There are notable differences among these values in the Potomac Economics model compared to the Brattle model which produced the CONE value that was approved by the PUCT in 2024.

### 1. Interpreting Single-Year Net Revenues

In 2024, marginal gas generators did not earn enough to cover their annualized capital costs. The CONE for CTs ranged from $102 per kW-yr to $106 per kW-yr, while their net revenues averaged only $68 per kW-yr. Similarly, CC units had a CONE between $116 per kW-yr and $121 per kW-yr, with average net revenues of $89 per kW-yr. While this shortfall may seem concerning in isolation, years like 2024 occur often and are not a threat to resource adequacy because one should expect tighter conditions to occur in other years that can produce revenues substantially above CONE.

If ERCOT's elevated load forecast discussed later in this chapter materializes, rising demand could again result in tighter conditions and stronger net revenue years. As always, single-year revenue results should be understood in the context of longer-term investment cycles. Generation developers are forward looking regarding revenue expectations and will often engage on forward contracting based on these expectations to lock in revenues and support financing for new projects. Hence, while historical net revenues may provide an empirical benchmark, investment will be driven by forward-looking expectations of load growth, generation development, interconnection costs, and market design changes that together determine profitability of new investment.

## D. Profitability of Additional Resource Classes

In addition to discussing the profitability of natural gas in the context of CONE in the previous section, we also discuss nuclear energy and coal in this subsection. IRRs and ESRs have been treated at length in other chapters of this report.

***Nuclear Energy.*** According to the Nuclear Energy Institute's "Nuclear Costs in Context" report, the average total generating cost for nuclear energy was $31.76 per MWh in 2023 and have been relatively stable.[50] The total generating cost is composed of: fuel costs, capital costs, and operating costs. Operating costs, which include expenses related to maintenance, security, and

50 https://www.nei.org/resources/reports-briefs/nuclear-costs-in-context

labor, remained nearly flat at $19.38 per MWh, making up the largest portion of total costs. Plants with multiple units benefit from an economy of scale and outperform the average, particularly in operating costs. Given that the average zonal energy prices in 2024 ranged from $29.58 to $35.33 per MWh throughout the ERCOT market, typical nuclear resources would likely have covered their costs but may not have been profitable. As discussed above, however, prices and revenues can fluctuate substantially from year to year so it is not clear that nuclear resources would be unprofitable in the long term.

***Coal.*** According to a December 2023 report from the U.S. Energy Information Administration (EIA), variable O&M costs for coal-fired power plants, excluding fuel, amount to approximately $6.40 per MWh. The same report estimates fixed operations and maintenance (O&M) costs at $61.60 per kW-yr,[51] which, assuming an 85% capacity factor, translates to roughly $8.28 per MWh. In ERCOT, the average fuel cost for coal-fired resources is roughly $8.50 per MWh.[52] Combined, this implies that the marginal production cost of coal-fired units in ERCOT is around $23.18 per MWh, which is lower than the national average largely due to the availability of low-cost Powder River Basin (PRB) coal. Given the prevailing energy prices in ERCOT in 2024, coal resources would have been profitable to run in many hours.

## E. Peaker Net Margin

We reiterate that net revenue is the primary driver of resource adequacy, as it determines whether generators have sufficient incentive to invest or remain in the market. While this revenue often arises from shortage conditions, it can also result from broader supply and demand dynamics, such as the artificial shortage created by ECRS procurement in June 2023. Generators choose to enter the market when they anticipate that future market conditions will allow them to earn a sufficient return on investment. However, there are instances, like Winter Storm Uri in 2021, when single-year revenues spike well beyond what is necessary to support new entry should that revenue level be sustained. A resource owner is seeking an average net revenue across the investment horizon that will provide a positive return on the investment. This involves a mix of low and high net revenue years. If net revenue is too volatile over a period of years, even high net revenue years may not produce new investment due to perceived risk by the developer. In this situation, extremely high net revenue years may produce excess cost without an investment

51 https://www.eia.gov/analysis/studies/powerplants/capitalcost/pdf/capital_cost_AEO2025.pdf

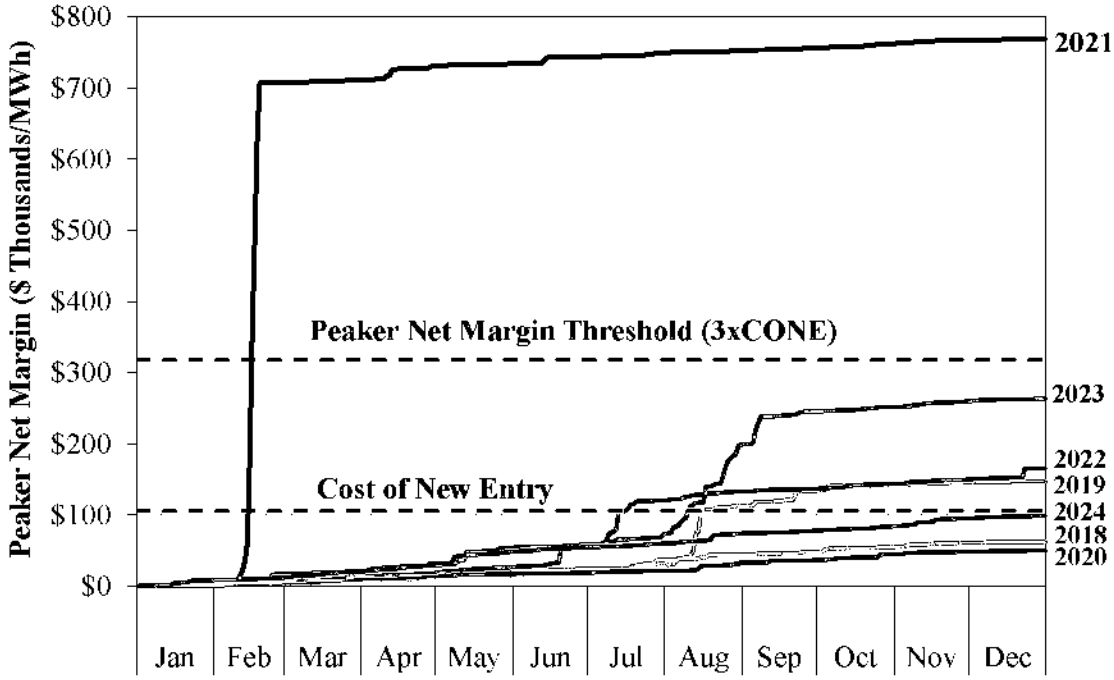
52 In ERCOT, most coal is imported from the Powder River Basin (PRB), where the average coal price in 2024 was about $0.80 per MMBtu. The average heat rate of coal-fired power plants has remained relatively stable over the past decade, increasing slightly from 10.4 MMBtu per MWh in 2013 to 10.7 MMBtu per MWh in 2023 as the national fleet continues to age. Based on a 10.7 MMBtu per MWh heat rate and $0.80 per MMBtu fuel cost. See https://www.eia.gov/electricity/annual/html/epa0801.html and https://www.eia.gov/coal/markets/#tabs-prices-2.

response to the price signal. To manage this dynamic, ERCOT uses the PNM threshold as a safeguard as outlined in TAC §25.509 of the PUCT's Electric Substantive Rules.[53]

### 1. Peaker Net Margin Threshold

PNM serves as a simplified benchmark for the annual net revenue that a hypothetical gas peaking unit could earn in the ERCOT market.[54] If, over the course of a calendar year, PNM exceeds a threshold of three times the CONE, equivalent to $315,000 per MW-year, the System-Wide Offer Cap (SWCAP) is reduced from $5,000 per MWh to $2,000 per MWh for the remainder of that year. This mechanism is designed to limit excessive shortage pricing once investment signals are deemed sufficient. Notably, this threshold has been exceeded only once in ERCOT's history, on February 16, 2021, during Winter Storm Uri. Figure 57 shows the PNM values for the past seven years.

**Figure 57: Peaker Net Margin, 2018-2024**




It is important to note that our net revenue calculation differs from ERCOT's PNM methodology. In our analysis, we assume a heat rate of 10.5 MMBtu per MWh, include variable O&M costs of $4 per MWh, and apply a total outage rate of 10%, which we believe reflects a more realistic estimate of generator performance and costs. By contrast, ERCOT's PNM calculation uses a simplified approach with a 10.0 MMBtu per MWh heat rate and excludes both

53 https://ftp.puc.texas.gov/public/puct-info/agency/rulesnlaws/subrules/electric/25.509/25.509.pdf

54 The proxy combustion turbine in the Peaker Net Margin calculation assumes a heat rate of 10 MMBtu per MWh and includes no other variable operating costs or startup costs.

variable O&M costs and outage rates. As a result, our calculation in Section C of this chapter produces values lower than those derived using ERCOT's PNM methodology.

## F. ERCOT's Reliability Standard

### 1. Background

A reliability standard prescribes a level of supply that is required in order to meet certain reliability criteria. The assessment that leads to a prescribed standard, in terms of installed capacity, assesses potential reliability under various system conditions including more extreme conditions as can be experienced during winter cold snaps and summer heat waves. Generally, it serves as a benchmark for determining if there is sufficient capacity in the system for reliable operation. If a reliability standard is mandatory, it serves as imposed demand for installed capacity that can drive new investment in periods when the standard is not otherwise met.

The foundation for ERCOT's reliability standard was established through Senate Bill (SB) 3, passed by the 87th Texas Legislature in the aftermath of Winter Storm Uri in 2021. Among its wide-ranging reforms to improve electric grid resilience, SB 3 directed the PUCT to develop and implement a formal reliability standard for the ERCOT power region. This legislative mandate recognized the need for a clearer definition of acceptable system reliability and the mechanisms by which it should be evaluated. In response, the PUCT adopted 16 Texas Administrative Code (TAC) §25.508, which formalizes a probabilistic reliability standard based on loss of load expectation (LOLE), along with additional criteria for the duration and magnitude of load shed events.[55] In this section, we will introduce the requirements of the reliability standard and its importance to resource adequacy, summarize the analysis we submitted in July 2024, [56] and reiterate the proposal that arose out of this analysis.

### 2. TAC §25.508 Requirements

The new rule establishes a formal probabilistic reliability standard for the ERCOT system, structured around three key metrics:

- **Frequency:** The LOLE must be no greater than 0.1 events per year, or one event every ten years, on average.
- **Duration:** The maximum expected duration of a loss of load event must be less than 12 hours, with a 1.00% exceedance tolerance.

55 The PUCT organized the Reliability Standard under Project 54584, found here: https://interchange.puc.texas.gov/Search/Filings?ControlNumber=54584

56 Our comments are filed under: https://interchange.puc.texas.gov/search/documents/?controlNumber=54584&itemNumber=91

- **Magnitude:** The expected highest hourly level of load shed must be less than the amount of load that can be safely rotated, as determined by ERCOT, also with a 1.00% exceedance tolerance. ERCOT is required to annually determine and file the maximum amount of load that can be safely rotated during an event, along with the methodology used to calculate it.

Starting in 2026, ERCOT must conduct a reliability assessment at least once every three years to determine whether the system meets the standard and is likely to continue meeting it for the following three years. If the assessment shows the standard is not met, ERCOT must propose potential market design changes, and we (the IMM) must independently review those proposals.

### 3. Importance of a Reliability Standard

It is important to discuss the reliability standard because it directly shapes how ERCOT evaluates whether the system has sufficient resources to meet demand under a range of conditions. By formalizing a standard for loss of load events, along with limits on their duration and magnitude, the rule introduces clear expectations for system performance. This, in turn, has implications for resource adequacy, as the market must ensure that enough capacity and operational flexibility are available to meet the standard. Understanding how the reliability standard interacts with market design and investment signals is essential to evaluating whether ERCOT's resource mix can continue to deliver reliable service.

The reliability standard is closely tied to the concept of the VOLL, which represents the economic cost customers incur when electricity service is interrupted. In effect, the standard sets an implicit level of reliability that the system must deliver, and the cost of meeting that standard reflects the value society places on avoiding outages. If the standard is too stringent, it may imply a VOLL far higher than what customers are actually willing to pay, leading to excessive investment or market interventions. Conversely, a weak standard could result in underinvestment and unacceptable reliability outcomes. For this reason, it is important to ensure that the adopted reliability standard reflects a reasonable and economically justified VOLL, balancing the cost of reliability with the cost of outages.

### 4. Reliability in ERCOT

ERCOT operates as an energy-only market, meaning that new investment is incentivized primarily through shortage pricing. Higher prices during tight supply conditions signal the need for additional resources. However, this creates a fundamental tension: in order to trigger investment signals, the system must approach conditions of shortage, which inherently threatens reliability. To reconcile this, the VOLL must be set extremely high to support both effective shortage pricing and an ambitious reliability standard. This challenge is one reason many other electricity markets rely on capacity markets, which provide separate payments to ensure long-term resource adequacy.

In our 2022 State of the Market Report, we estimated that ERCOT's shortage pricing mechanism, based on the ORDC, implies a VOLL of approximately $47,000 per MWh. This is significantly lower than the roughly $200,000 per MWh implied by a typical 1-in-10 reliability standard or the presumably materially higher cost per MWh needed to support a reliability standard like the one adopted by the Commission.

### 5. Concerns and Conclusions

A single reliability standard based on Expected Unserved Energy (EUE) offers important advantages over a multi-factor standard. EUE captures both the duration and magnitude of potential loss-of-load events, meaning it inherently reflects the severity and length of outages in a single, unified metric. This makes it well-suited for aligning with a reasonable VOLL and simplifies both modeling and implementation. In contrast, applying three separate mandatory standards, for frequency, duration, and magnitude, can over-prescribe installed capacity and result in implied VOLLs far exceeding reasonable levels. In some cases, the implied VOLL from trying to meet a binding magnitude or duration constraint could exceed $1M per MWh, far beyond what most consumers would be willing to pay to avoid outages.

Our primary concern lies with the magnitude standard, which we believe is the most volatile and sensitive to planning model assumptions. Small changes in load forecasting methods, resource modeling, or historical weather scenarios can sharply alter the estimated peak load shed, potentially making the magnitude standard binding even when the overall system is adequate. We also find that the duration standard adds an unnecessary boundary condition without providing meaningful reliability value on its own. In our original comments to the Commission, we recommended eliminating both the magnitude and duration criteria and replacing them with a single EUE-based standard that would more effectively reflect reliability risk and better support economically justified planning.

While the Commission ultimately adopted the three-standard approach, it did take steps to address some of our concerns by relaxing the exceedance tolerances associated with the duration and magnitude metrics, which helps mitigate their potential to drive excessive investment. Since the current reliability standard may have significant impacts on generators and consumers alike, we advise clarifying formally whether the Commission intends the reliability standard to serve as a binding objective for ERCOT or remain an aspirational target to inform market participants. Absent this clarification, we interpret the directive to ERCOT to produce proposals to meet the standard as an indication that the standard is or will be mandatory.

## G. Communicating Resource Adequacy

The way resource adequacy is communicated plays a critical role in shaping the expectations and decisions of market participants. Generators, LSEs, and other stakeholders rely on ERCOT's resource adequacy assessments to inform long-term investment strategies, operational planning, and risk management. While individual market participants may interpret market signals differently based on their own risk tolerances and business models, the formal reports and forecasts published by ERCOT serve as widely referenced benchmarks. These reports help frame expectations around future supply and demand conditions, influencing market behavior in tangible ways.

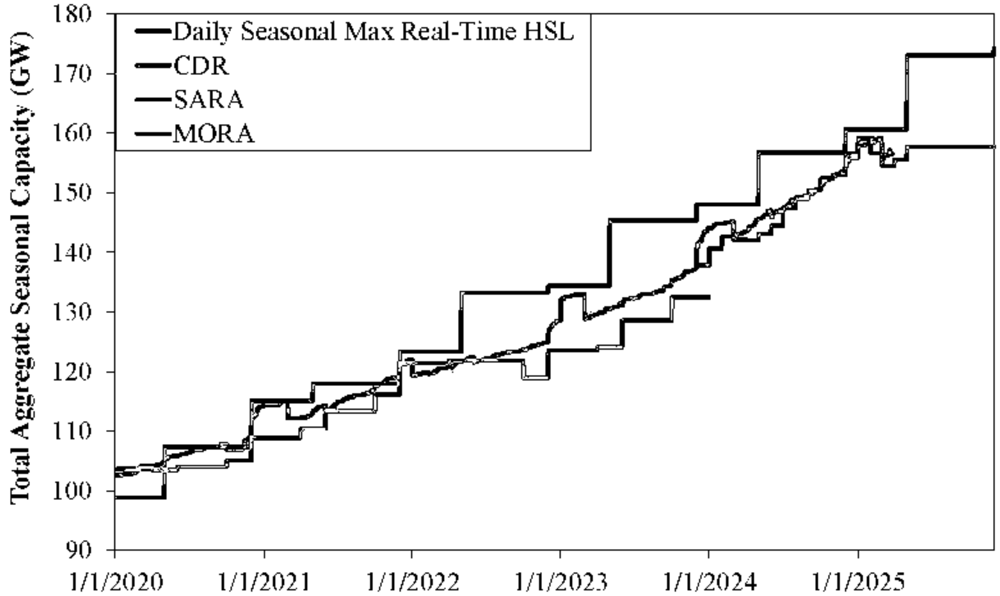
In this section, we review the primary reports through which ERCOT communicates resource adequacy to the market. We will discuss how ERCOT's Monthly Outlook for Resource Adequacy (MORA), the Long-Term Load Forecast (LTLF), and the Capacity, Demand, and Reserves (CDR) report convey expectations about system conditions over varying time horizons. We will also highlight key limitations in ERCOT's current resource adequacy communications.

### 1. Monthly Outlook for Resource Adequacy

The MORA report provides an early assessment of the risk that ERCOT may need to issue an Energy Emergency Alert (EEA) or initiate controlled outages during the reporting month. Introduced in 2023 to replace the Seasonal Assessment of Resource Adequacy (SARA), the MORA offers more granular, month-ahead insights. It uses probabilistic modeling to estimate the likelihood of insufficient operating reserves during peak demand periods and includes scenarios showing expected demand and resource availability. The MORA is particularly useful for forecasting resource adequacy conditions in the near term, typically one to two months in advance, and should be viewed as a short-term planning tool rather than a long-term resource adequacy assessment.

Figure 58 compares the short-term forecast accuracy of the MORA, SARA, and CDR reports against the actual Daily Seasonal Max Real-Time HSL, which represents the total online capacity approved to operate at maximum output on any given day. Among the three, the MORA shows the closest alignment with actual conditions, consistently tracking the Daily Max HSL throughout the year. By contrast, the SARA report, which was last published in 2023, showed less accuracy, in part because it was only updated on a seasonal basis and could not capture month-to-month changes in resource availability.

**Figure 58: Short-Term Forecast Accuracy, MORA, SARA, & CDR**




### 2. Capacity, Demand, and Reserves Report

The CDR report is ERCOT's primary long-term resource adequacy forecast. Published twice a year, the CDR provides a five-year outlook of expected system conditions by projecting future capacity additions and retirements alongside forecasted peak demand. The report is designed to inform market participants, regulators, and stakeholders about whether anticipated resources will be sufficient to meet projected demand under normal weather conditions. Unlike the MORA, which is a short-term operational tool, the CDR serves as a planning tool to provide a broad view of resource adequacy trends over the medium term. As a result of its focus on long-term forecasts, the CDR is less effective at communicating short-term resource adequacy, a limitation that is evident in its reduced accuracy compared to the MORA in Figure 58.

Over the past year, the CDR report has undergone significant improvements aimed at providing a more accurate and realistic assessment of future resource adequacy. NPRR 1219, implemented in October 2024, implemented a series of improvements to the CDR report.[57] One of the most notable changes is the shift from using peak average capacity contribution to the more sophisticated Effective Load Carrying Capability (ELCC) methodology for variable resources like wind and solar. The CDR also incorporates the ELCC of ESRs, where ELCC increases non-linearly based on system duration as larger systems provide diminishing returns. This change better reflects the contribution of these resources to reliability, particularly as their penetration has grown. The report now also includes planned retirements of generation resources in its forecasts, providing a clearer picture of potential supply shortfalls in future years.

[57] NPRR 1219 introduced several improvements to the CDR report and we only cover a couple of them here. The comprehensive language can be found here: https://www.ercot.com/mktrules/issues/NPRR1219

The shift from using peak average capacity contribution to ELCC in the CDR report is particularly significant because it accounts for the evolving timing of system stress. Specifically, it reflects the shift of the net peak load hour from the afternoon, when solar output is typically at its highest, to the evening hours, when solar generation diminishes or disappears entirely. This change highlights the growing importance of the net peak load, which measures demand after subtracting available renewable generation. Historically, the system's most strained conditions occurred at the firm peak load, the highest gross demand hour. However, as renewable penetration has increased, the hour of greatest reliability risk has shifted to the evening hours when solar output declines.

While the CDR report has undergone meaningful improvements in recent years, several significant deficiencies remain that limit its usefulness as a tool for stakeholders to assess long-term resource adequacy. These limitations can lead to an incomplete or misleading view of future supply and demand conditions, affecting how market participants plan for the future. The key deficiencies are as follows:

**Excludes most demand response resources**: The CDR report does not account for the contribution of demand response capacity outside of Emergency Response Service (ERS). According to the November 2024 Annual Report on ERCOT Demand Response, there are approximately 10.5 GW of Non-Controllable Load Resources (NCLRs) and 1.2 GW of Controllable Load Resources (CLRs). Combined, these resources total 11.7 GW of flexible load that reliably reduces consumption during periods of system strain, the very conditions the CDR is intended to evaluate. During these events, these load resources will reliably reduce to a fraction of their peak demand.

**Unreliable beyond two-year horizon**: The CDR does not anticipate new generation resources that may enter the interconnection queue in the outer years of its five-year forecast horizon. Many of these resources could feasibly become operational by the end of the forecast period, yet they are excluded from the analysis. This limits the CDR's ability to accurately represent the evolving resource mix and leads to a conservative, and potentially misleading, view of long-term resource adequacy. We will discuss how generation is forecasted in an upcoming section.

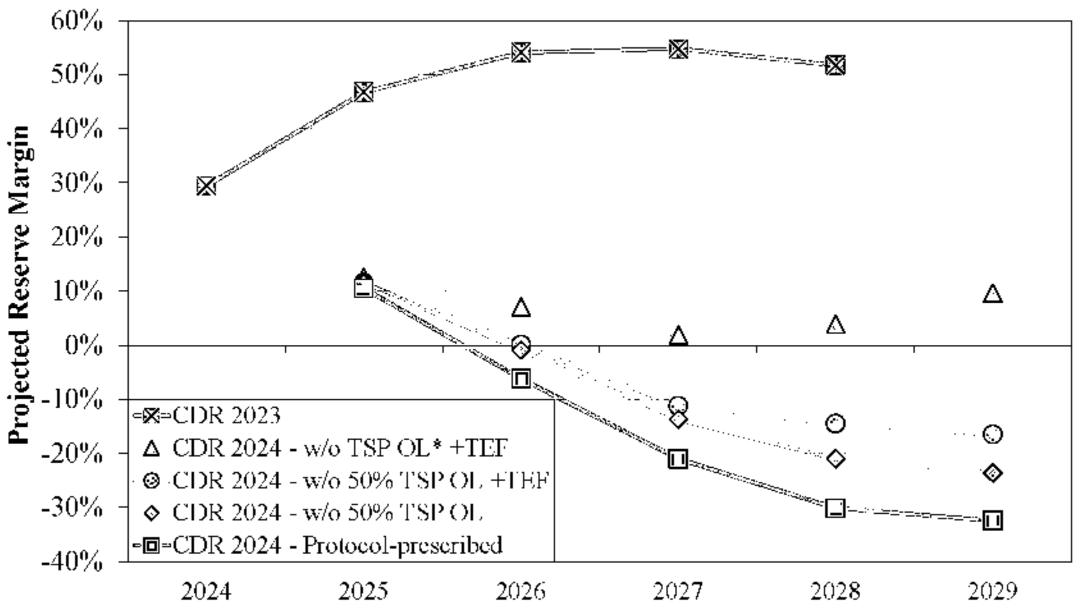
**Relies on planning data**: The CDR depends heavily on planning data submitted by market participants, including projected capacities and operational dates for future generation resources. This information is often incomplete or inaccurate, as it relies on voluntary self-reporting without reconciliation against actual operational outcomes. Without a systematic process to reconcile this planning data with operations data, the CDR's forecasts remain vulnerable to errors and may misrepresent the true state of resource adequacy.

### 3. Impact on Reserve Margin

The planning reserve margin is a metric used to measure the difference between the total available generation capacity and the expected peak demand, expressed as a percentage of peak demand. It serves as a simple indicator of whether there is sufficient capacity to meet demand under typical system conditions. A higher reserve margin indicates more available capacity, reducing the risk of shortages, while a lower margin suggests tighter supply conditions. A negative reserve margin means that projected generation capacity is insufficient to meet peak demand, increasing the likelihood of reliability concerns, price spikes, and potential load-shedding events.

Recent changes to the CDR report have had a substantial impact on projected reserve margins. While the December 2023 CDR projected reserve margins ranging from 27% to 51.7% five years out,[58] the December 2024 CDR projects a much lower range of -32.4% to 9.6% over the same horizon.[59] This dramatic decline is driven by two primary changes in the CDR methodology. First, the shift to using ELCC reduces the contribution of renewable resources during net peak load conditions, leading to lower counted capacity. Second, ERCOT now mandatorily includes TSP officer letter loads in its load forecast, significantly increasing the expected demand in future years. Figure 59 compares the reserve margin projections between the 2023 and 2024 CDR reports.[60]

**Figure 59: Planning Reserve Margin, CDR 2023 vs CDR 2024**



*OL – Officer Letter

58 https://www.ercot.com/files/docs/2023/12/07/CapacityDemandandReservesReport_Dec2023.pdf

59 https://www.ercot.com/files/docs/2025/02/12/CapacityDemandandReservesReport_December2024.pdf

60 ERCOT produced the May 2025 CDR just prior to the publication of this report. The reserve margins across all considered scenarios vary between -20.6% and -50.3% for the peak net load hour in the summer. It can be found here: https://www.ercot.com/files/docs/2025/05/15/CapacityDemandandReservesReport_May2025.pdf

In the Load Forecast subsection, we examine in more detail what transmission service provider (TSP) officer letter loads are and how ERCOT's inclusion of them has affected the load forecast and, by extension, the reserve margin. First, however, we will finish out this section with a brief discussion of the final report that ERCOT uses to communicate resource adequacy, the LTLF.

### 4. Long-Term Load Forecast

The LTLF is published yearly and serves as ERCOT's primary tool for projecting system load growth over an extended period, typically covering a ten-year horizon.[61] The LTLF provides detailed forecasts of future peak demand and energy consumption, using econometric models informed by economic and demographic trends, weather data, and other variables. The forecast includes six major components: base economic load, large flexible loads (LFLs), electric vehicle (EV) load, rooftop photovoltaic (PV) generation, contracted large industrial loads, and officer letter loads. Base load is forecasted using traditional economic indicators such as population growth, housing stock, and employment data, while other categories, including EVs and rooftop PV, are modeled based on adoption trends and historical patterns.

Despite its comprehensive scope, the LTLF report has limitations that affect its usefulness as a forecasting tool. Most notably, while contracted and TSP officer letter loads comprise the vast majority of the anticipated new load in ERCOT over the next several years, the LTLF does not evaluate the likelihood of these loads arriving within the forecast period. Instead, it includes these loads in full once they are reported, regardless of the development risks, permitting challenges, or other barriers to realization they face. ERCOT's 2025 LTLF adjustment to the loads submitted by TSPs is an improvement over its process in the 2024 LTLF but remains based on limited experience and data related to officer letter loads, making a data-driven approach challenging. This approach, combined with the narrow scope of information ERCOT receives from TSPs through its annual request for information (RFI) process and the lack of a more robust history of the proportion of stated load expectation actually becomes commercial, limits the potential accuracy of future resource adequacy. ERCOT did evaluate alternative scenarios in the most recent CDR report, which provided additional value to developers, consumers, and policy makers. Further exploration of how to better reflect uncertainty around the largest drivers of future demand will provide even more accurate and valuable projections.

## H. Load Forecast

ERCOT's load forecasts have changed dramatically over the past two years, reflecting new policies, evolving methodologies, and a rapidly shifting load landscape. Historically, peak demand in ERCOT grew at a steady pace, increasing from 74.7 GW in 2019 to 85.6 GW in 2024, for an average annual growth rate of 2.76%.[62] However, recent forecasts have diverged sharply

61 https://www.ercot.com/files/docs/2024/01/18/2024_LTLF_Report.docx

62 https://www.ercot.com/gridinfo/load/load_hist

from this trend, with ERCOT projecting much higher levels of future demand. This section reviews the sequence of peak load forecasts ERCOT has published in the past two years, explains how policy changes such as the inclusion of officer letter loads have contributed to these shifts, identifies the persistent limitations in ERCOT's forecasting process, and considers the scale of transmission investment that may be required if these forecasts materialize. Table 9 summarizes the range of load forecasts ERCOT has published since December 2023, through both the CDR and LTLF reports.

**Table 9: ERCOT's Load Forecasts Summary**

| | Firm Peak Load (GW) | | | | Net Peak Load (GW) | | | |
|---|---|---|---|---|---|---|---|---|
| **Report** | **2024** | **2025** | **2029** | **2030** | **2024** | **2025** | **2029** | **2030** |
| Dec 2023 CDR | 80.0 | 80.6 | 85.5 | 86.5 | -- | -- | -- | -- |
| May 2024 CDR | -- | 80.6 | 82.7 | 82.8 | -- | -- | -- | -- |
| July 2025 LTLF | 86.0 | 90.5 | 140.9 | 148.0 | -- | -- | -- | -- |
| Dec 2024 CDR | -- | 86.7 | 137.1 | -- | -- | 83.0 | 137.1 | -- |
| April 2025 LTLF TSP Provided | -- | 93.3 | 195.7 | 207.0 | -- | -- | -- | -- |
| April 2025 LTLF ERCOT Adjusted | -- | 85.4 | 127.9 | 138.0 | -- | -- | -- | -- |
| May 2025 CDR | -- | -- | 128.3 | 138.4 | -- | -- | 115.9 | 126.6 |

### 1. Load Forecast Chronology

We begin by presenting a chronology that illustrates how ERCOT's forecasts have diverged over time as different data, methodological aspects, and observation have been incorporated over time.

**June 2021.** The Texas Legislature passed SB 1281, which took effect in September 2021. SB 1281 introduced Section 37.056(c-1) of the Utilities Code, which required load forecasts to consider (1) historical load, (2) forecasted load, and (3) additional load seeking interconnection.[63]

**December 2022.** The PUCT, who had organized the implementation of SB 1281 under Project 53403 earlier that year, implemented 16 TAC §25.101(b)(3)(A)(ii)(II) which requires that loads in the load forecast be substantiated by quantifiable evidence of projected load growth.[64] In the order adopting the amendments to 16 TAC §25.101, the PUCT stated that it will give great weight to written documentation by a TSP to ERCOT that a given transmission line is needed to interconnect certain loads.

63 https://capitol.texas.gov/tlodocs/87R/billtext/html/SB01281F.htm

64 https://interchange.puc.texas.gov/search/documents/?controlNumber=53403&itemNumber=86

**May 2023.** NPRR 1180[65] and PGRR 107[66] are introduced into the stakeholder process. Together, they introduce and define "Substantiated Load" and "Unsubstantiated Load" in ERCOT's protocols. Both NPRR 1180 PGRR 107 are approved in January 2025, and define Substantiated Loads to refer to loads submitted by TDSPs for planning purposes substantiated by (1) an executed interconnection or other agreement, (2) an independent third-party load forecast deemed credible by ERCOT, or (3) a letter from a TDSP officer attesting to such load, which may include load for which a TDSP has yet to sign an interconnection agreement. The latter of these criteria introduces the concept of officer letter loads, discussed in greater detail later in this section.

**June 2023.** The Texas Legislature passed House Bill 5066, which clarified the definition of "additional load seeking interconnection" in Section 37.056(c-1) to include load that has not yet executed an interconnection agreement.[67] HB 5066 took immediate effect.

**November 2023.** ERCOT initiated its RFI process, soliciting submissions from TSPs for Substantiated Loads to be considered in ERCOT's long-term transmission planning and resource adequacy forecasts.

**December 2023.** ERCOT published its December 2023 CDR. This report does not include officer letter loads as the RFI process was not yet complete.

**May 2024.** ERCOT published its May 2024 CDR. NPRR 1180 and PGRR 107 were not yet approved by the PUCT so that officer letter loads are discussed but not included in most calculations.[68]

**July 2024.** ERCOT published its revised 2024 LTLF report, whose forecast includes officer letter loads. It projects a peak demand of 148 GW in 2030, up from 86.5 GW and 82.8 GW projected by the December 2023 CDR and May 2024 CDR reports, respectively.

**November 2024.** ERCOT issued its annual RFI to TSPs.

**January 2025.** NPRR 1180 and PGRR 107 are approved by the PUCT. The most significant distinction between the originally introduced version and the approved version is the clarification made by HB 5066, discussed earlier.

**February 2025.** ERCOT published its revised December 2024 CDR report. This report includes officer letter loads, including scenarios where some of the projected load may not materialize.

65 https://www.ercot.com/mktrules/issues/NPRR1180

66 https://www.ercot.com/mktrules/issues/PGRR107

67 https://capitol.texas.gov/tlodocs/88R/billtext/html/HB05066H.htm

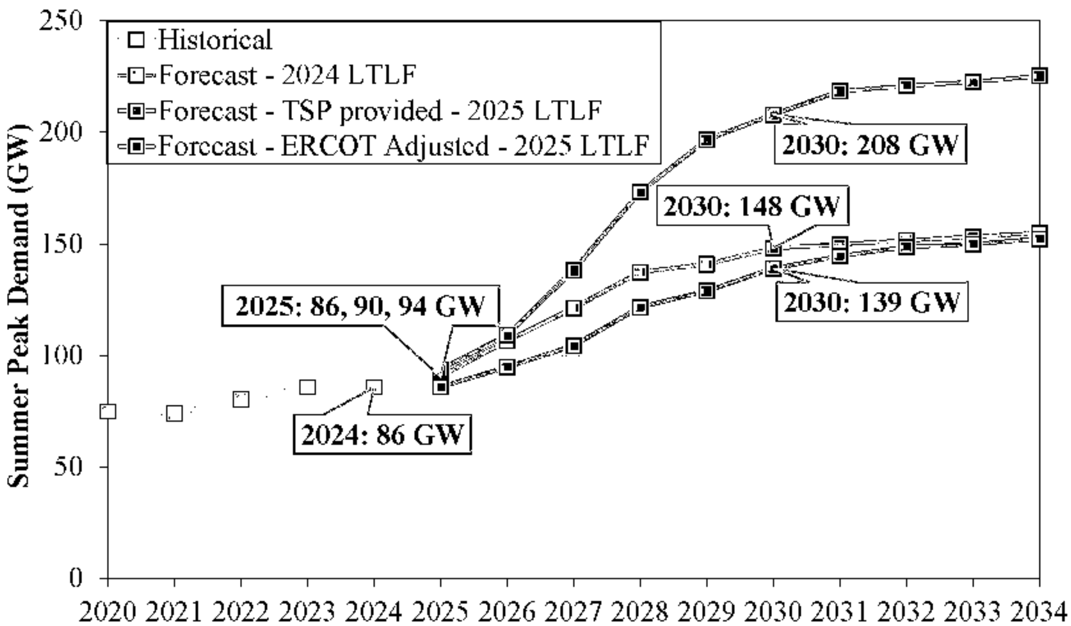
68 https://www.ercot.com/files/docs/2024/05/24/CapacityDemandandReservesReport_May2024_Revised.pdf

**April 2025.** ERCOT published its 2025 LTLF report. The TSP-provided load forecast for 2030 balloons to a summer peak demand of 208 GW. ERCOT also publishes an adjusted forecast that discounts the projected load to a summer peak demand of 138 GW.

**May 2025.** ERCOT filed with the PUCT a request for a good cause exception that would allow ERCOT to use its adjusted forecast for planning purposes in its 2025 regional transmission plan (RTP). As of this report's publication, this request has not yet been approved and is pending. ERCOT also published its May 2025 CDR.

To sum up, the 87th and 88th legislative sessions introduced new load forecasting requirements that have significantly inflated ERCOT's peak demand forecasts for the near future. These forecasts suggest that ERCOT will need to accelerate investments in new transmission projects and upgrades to keep pace with projected demand. The 2024 LTLF, 2025 ERCOT Adjusted Forecast, and 2025 TSP Provided Forecast show load growth rates of 9.7%, 8.5%, and 16.2%, respectively. These growth rates are three to six times higher than the historical growth rate of 2.76%. Figure 60 illustrates the peak demand forecasts as published in ERCOT's 2024 and 2025 LTLF reports.

**Figure 60: ERCOT Long-Term Peak Demand Forecast**




Next, we review how the net load forecast is calculated.

## 2. Net Forecast Calculation

The LTLF employs the following equation to calculate its net load forecast:

$$Net\ Forecast = Base\ Load\ Forecast + EV\ Forecast + LFL\ Forecast - PV\ Forecast + Contracted\ Load + Officer\ Letter\ Loads$$

ERCOT's long-term load forecast builds a system-wide net forecast by combining six categories: the base economic forecast, electric vehicle (EV) forecast, rooftop photovoltaic (PV) forecast, large flexible load (LFL) forecast, contracted load forecast, and officer letter load forecast. These components are layered using a waterfall approach. The base economic forecast is developed from econometric models, while EV forecasts use registration data mapped to ZIP codes. The rooftop PV forecast estimates peak demand reductions by customer class and weather zone. LFL projections account for typical curtailment during peak periods, and weather variability is considered for normal and probabilistic scenarios. The 2025 LTLF projects 2,006 MW of peak demand from EVs and a 2,083 MW peak demand reduction from rooftop PV by 2030.

The 2025 LTLF marks the first time ERCOT applied adjustment factors to contracted and officer letter load forecasts, based on observed delays and realization rates. This is an improvement over past practices, where such loads were included in full without adjustments.

### 3. Contracted Loads vs Officer Letter Loads

Contracted loads refer to large loads that have entered into interconnection agreements with a transmission service provider, making them relatively certain to come online. In contrast, officer letter loads are based on letters submitted by TSP officers expressing the intent to interconnect, but they have not yet finalized contractual commitments. As a result, officer letter loads are considered less certain and may carry a higher risk of delay or cancellation. Table 10 summarizes the contracted and officer letter loads used in ERCOT's 2024 and 2025 LTLF reports.

**Table 10: 2024 & 2025 RFI Data, 2030 Forecast (MW)**

| LTLF By 2030 | Type | Crypto/ LFL | Data Center | Hydrogen/ Ammonia | Oil & Gas | Industrial | Total |
|---|---|---|---|---|---|---|---|
| TSP Provided - 2024 | Contracted | 3,543 | 10,301 | 3,100 | 650 | 1,119 | 18,713 |
| | Officer Letter | 2,335 | 17,363 | 13,945 | 1,042 | 2,214 | 36,898 |
| | Total | 5,878 | 27,664 | 17,045 | 1,692 | 3,332 | 55,611 |
| TSP Provided - 2025 | Contracted | 4,920 | 11,885 | 4,100 | 2,623 | 3,179 | 26,707 |
| | Officer Letter | 6,402 | 66,081 | 8,862 | 917 | 7,885 | 90,146 |
| | Total | 11,321 | 77,965 | 12,962 | 3,540 | 11,064 | 116,853 |
| ERCOT Adjusted - 2025 | Contracted | 4,176 | 5,746 | 4,100 | 2,617 | 2,921 | 19,560 |
| | Officer Letter | 3,325 | 16,429 | 3,802 | 508 | 4,159 | 28,223 |
| | Total | 7,500 | 22,175 | 7,902 | 3,125 | 7,080 | 47,783 |

We highlight a few key statistics derived from Table 10:

- The forecasted load submitted by TSPs more than doubled from the 2024 RFI to the 2025 RFI. Nearly 80% of this increase, approximately 49 GW, came from growth in data center officer letter loads.
- Forecasted load in the Crypto/LFL and oil and gas categories roughly doubled between the 2024 and 2025 RFIs, while industrial load more than tripled.
- Planned Hydrogen/Ammonia projects saw significant delays and cancellations between the 2024 and 2025 RFIs, resulting in a net decrease of 4 GW across both categories.
- Officer letter loads make up 66.4% of forecasted load growth in the 2024 LTLF, 77.1% in the 2025 LTLF TSP Provided forecast, and 59.1% in the 2025 LTLF ERCOT Adjusted forecast.

### 4. Transmission Investment

ERCOT has historically invested an average of $3 billion per year in building or upgrading transmission infrastructure, with that figure rising to $3.78 billion in 2024.[69] If we assume that transmission investment scales proportionally with load growth, then meeting the projected 8.5%-16.2% year-over-year increase in peak demand over the next five years would require ERCOT to multiply its annual investment in transmission projects three to six times over. However, this is a simple linear extrapolation that does not account for the secondary effects of such rapid growth, particularly the increased demand for labor, materials, and equipment, all of which could strain supply chains and escalate costs even further.

It is also important to note that the cost of new transmission infrastructure in ERCOT is socialized across all market participants, in line with Texas' open access laws. Under this structure, entities seeking to interconnect are not directly responsible for the full cost of the transmission upgrades required to serve their load, which lowers the barrier to entry and supports Texas' reputation as an attractive market for investment. However, this model also means that the financial burden falls on existing ratepayers, who ultimately fund transmission expansion through regulated transmission charges.

### 5. ERCOT's April 2025 Load Forecast Adjustment

When ERCOT first incorporated officer letter loads into its 2024 LTLF, it did so without explaining what officer letters are or acknowledging that these loads are far less likely to materialize than contracted loads or other forms of load growth. By including all 37 GW of officer letter loads without any adjustment or explanation, the forecast surged to 148 GW,

[69] https://www.ercot.com/files/docs/2025/01/27/2024-regional-transmission-plan-rtp-345-kv-plan-and-texas-765-kv-strategic-transmission-expans.pdf

implying an average annual growth rate of 9.7%. This sudden increase and lack of understanding of the data and methodology that produced it left stakeholders uncertain whether to treat the forecast as a credible signal for investment in new transmission or to discount it entirely.

In the 2025 LTLF, ERCOT introduced adjustment factors for the first time, using historical data to estimate how often officer letter loads actually materialize and energize. These adjustments delayed in-service dates for both contracted and officer letter loads by 180 days. They also reduced new data center demand to 49.8% of the originally requested capacity, and then further reduced all officer letter loads to 55.4% of the originally requested capacity. Contracted loads were not discounted besides the delay factor. These changes lowered the 2030 TSP Provided forecast from 208 GW to 139 GW.[70]

Understanding these adjustments requires distinguishing between two concepts: consumption and energization. Consumption refers to the peak demand a load actually uses compared to the MW it originally requested. Energization refers to whether a load comes online at all to begin drawing power.

ERCOT's adjustments were based on the following findings. As of January 31, 2025, 55.4% of officer letter loads had energized. Among the loads that did energize, only 22% of the originally requested capacity was actually being consumed. ERCOT discounted officer letter loads to 55.4% instead of 22% because it assumes that these loads may increase their consumption over time as operations ramp up. Effectively, ERCOT applied the energization rate to the consumption rate. For data centers, which account for the vast majority of forecasted load growth, ERCOT found that these facilities consumed only 49.8% of their requested capacity. This figure was based on a study of several large data centers over the past few years.

### 6. Validating the Forecast

It is difficult to validate ERCOT's forecast, and we do not attempt to do so here. Doing so would require access to detailed cost and transmission planning data that neither we nor ERCOT currently possess. The information necessary to assess the likelihood that a given load project will interconnect by a specific date resides with the individual TSPs. While a limited subset of this information is communicated to ERCOT through its annual RFI, the data is often incomplete and may quickly become outdated as project timelines shift. It is also important to understand that ERCOT has just over a year of data and experience with officer letter loads, which limits its ability to establish a fully data-driven approach and publish defensible discount factors.

Indeed, the communication chain from market participants to the public leaves room for gaps and distortions. In the interconnection process, a prospective load submits information to the

70 https://www.ercot.com/files/docs/2025/04/07/8.1-Long-Term-Load-Forecast-Update-2025-2031-and-Methodology-Changes.pdf

TSP, which then conducts its own internal assessment of what is needed to support interconnection. ERCOT's yearly RFI does not capture this detailed evaluation. Instead, it collects high-level information, such as whether an interconnection agreement has been signed, the location of the load, and whether it qualifies as an officer letter load, along with a few other general data points. These inputs do not provide sufficient basis to assess the likelihood or timeline of interconnection, limiting the transparency and reliability of the load forecast.

## I. Generation Forecast

We conclude this chapter with a brief review of how generation capacity is forecasted and communicated in ERCOT. As previously discussed, generation forecasts are communicated exclusively through the CDR report, which serves as the primary source of forward-looking information on system capacity. The CDR calculates its generation forecast by combining current operational capacity with two additional categories: resources with signed interconnection agreements and those that are synchronized to the grid but not yet approved for commercial operation. This methodology allows the CDR to reasonably estimate the amount of capacity that is likely to be online within the next two years.

However, the CDR does not account for generation projects that have not yet signed an interconnection agreement, even if those projects are likely to come online in years three through five of the forecast horizon. As a result, the CDR's longer-term outlook tends to understate future capacity, especially beyond the two-year mark. Given these limitations, we emphasize that the CDR functions best as a medium-term forecasting tool, not a long-range planning document. Its attempt to forecast generation five years into the future can be misleading and unnecessarily alarming to stakeholders. This concern is particularly evident in the forecasted reserve margins shown in Figure 59, which reflect the limited scope of the generation forecast rather than a full picture of future system capability.

## J. Conclusion

The discussion around resource adequacy is a critical one to get right, as it shapes both investment decisions by market participants and regulatory responses from the Legislature and the Commission. A mischaracterization of future system needs can lead to overinvestment, underinvestment, or misguided policy interventions. Below, we reiterate five key takeaways from this chapter.

First, the LTLF has functioned more as an accounting ledger than a forecasting model. It aggregates large volumes of anticipated load, primarily from contracted and officer letter loads, without applying adequate filters to assess the likelihood that these loads will materialize within the forecast period. While the current methodology captures what has been reported to ERCOT, it does not evaluate economic viability, permitting status, or development timelines. As a result, the forecast risks overstating future peak demand, which can distort perceptions of system adequacy and infrastructure needs. ERCOT's recent adjustment to its forecast improves this paradigm but is based on a limited data set that does not yet capture officer letter load behavior.

Second, the CDR suffers from similar limitations, particularly beyond its two-year horizon. While it reasonably captures generation and load additions already in motion, it fails to account for new resources that have not yet signed interconnection agreements but could feasibly enter commercial operations within the five-year forecast period. This structural limitation makes the CDR less a forward-looking tool and more a reflection of the current queue status. Its five-year reserve margin projections, as shown in Figure 59, can present a misleading picture of risk and may overstate the need for intervention.

Third, the weakness of the communication chain that underlies ERCOT's forecasting process. Load and generation data flows from market participants to TSPs, then to ERCOT through an annual RFI, and finally to the public through official forecasts. This process introduces multiple opportunities for information loss or misinterpretation. For example, ERCOT receives high-level data but not the detailed project status information held by individual TSPs, such as permitting progress or construction challenges, that would be necessary to assess the timing and viability of interconnection. The result is a forecast that lacks transparency and completeness.

The fourth takeaway concerns the uncertainty surrounding the reliability standard adopted in 2024. While the standard sets clear probabilistic benchmarks for system reliability, it remains unclear whether the Commission intends to treat it as a binding requirement or an aspirational guideline. Without that clarity, market participants may misinterpret the urgency or consequences of failing to meet the standard, which could lead to either overbuilding or delays in needed investment. This ambiguity could complicate planning and market design decisions moving forward.

Finally, if ERCOT's revised load forecast proves accurate, a substantial increase in transmission investment will be required to maintain reliability. ERCOT has historically invested around $3 billion per year in transmission upgrades, rising to $3.78 billion in 2024. But a 9.7%-16.2% annual increase in peak demand, as projected over the next five years, would require transmission investment to multiply by a factor of three to six. Since Texas' open access structure socializes transmission costs across all market participants, this shift could place a significant financial burden on existing ratepayers. A clear understanding of both the forecast and its implications is essential to preparing for this level of system expansion.

# VII. ANALYSIS OF COMPETITIVE PERFORMANCE

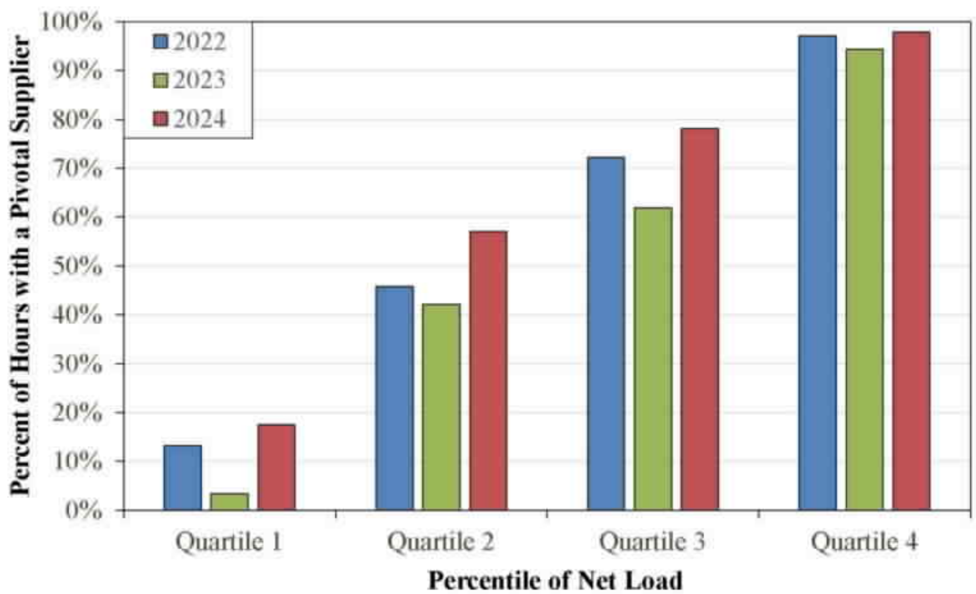
In this section, we evaluate market power from two perspectives: structural (does market power exist) and behavioral (have attempts been made to exercise it). This section begins by evaluating a structural indicator of potential market power, then evaluates market participant conduct by reviewing measures of potential physical and economic withholding. Finally, this section includes a high-level summary of the Voluntary Mitigation Plans (VMPs) in effect during 2024.

Based on these analyses, we find that the ERCOT wholesale markets generally performed competitively in 2024. However, our assessment of market power possessed by large suppliers and the extent of offer prices well in excess of competitive levels raises concern that may warrant additional scrutiny of VMP provisions and additional market power mitigation measures to capture instances outside of those facilitated by binding uncompetitive transmission constraints.

## A. Structural Market Power Indicators

The market is most competitive when no participant can withhold the capacity, either physically or economically via high-priced offers, in order to benefit by raising prices substantially. Traditional market concentration measures are not reliable market power indicators in electricity markets partly because they do not consider load obligations that affect suppliers' incentives to raise prices. They also do not account for excess supply, which affects the competitiveness of the market. A more reliable indicator of market power is whether a supplier is "pivotal," i.e., whether a suppliers' resources are required to meet demand for energy and ancillary services or manage congestion. Figure 61 shows the results of our pivotal supplier analysis by showing the frequency of hours where there is a pivotal supplier, grouped by net load level (quartile).

**Figure 61: Pivotal Supplier Frequency by Net Load Level**



During the top 25th percentile of net load occurring in each year, there was a pivotal supplier greater than 90% of the time. Inherently, high net load indicates a large demand to be satisfied by generation resources (and net imports) not including wind and solar. System conditions, including winter cold snaps and summer heat waves, along with a high degree of generation outages can have a significant impact on the balance of supply and demand which can directly impact the extent to which participants possess market power. Decision Making Entities (DMEs) with a high portfolio of non-intermittent generation are an important contributor during these hours. The frequency of hours where there are pivotal suppliers is expected to increase with the level of net load. As load reserve requirements increase, there is less excess supply to meet those needs. This increases the potential market power of participants. Pivotal suppliers, market participants with structural market power, existed in 63% of all hours in 2024, compared to 50% in 2023 and 57% in 2022.

We also evaluate competitiveness at a zonal level. The methodology follows the same structure as the system-wide evaluation with two exceptions. First, the zonal approach does not consider reserve requirements at the zonal level. ERCOT does not have zonal demand curves for reserves, so there is no explicit requirement that some reserves be sourced within a specific zone. Second, import capability into a zone is competing with zonal supply and is addressed through netting observed net imports into a zone from the load in that zone. The figures in Table 11 show, by zone, the percentages of hours during the top quartile of load where one or more pivotal suppliers existed.

**Table 11: Frequency of One or More Pivotal Suppliers in Top Quartile of Net Load by Zone**

| | Pivotal Frequency | | |
|---|---|---|---|
| | **2022** | **2023** | **2024** |
| Houston | 35% | 52% | 28% |
| North | 65% | 68% | 66% |
| South | 1% | 0% | 3% |
| West | 8% | 21% | 50% |

This analysis focuses on hours where the load level was in the highest 25% of the year, when supply is most likely to be tighter and lead to the potential exercise of market power. The Houston and North zones have the highest prevalence of structural market power in these high load hours. It is notable that the West zone also experienced a high frequency of structural market power in 2024. For perspective, there are 2,190 hours represented in the highest quartile of load throughout a year. That is 1,445 hours for the North zone in 2024, showing 66% of time with one or more pivotal suppliers. This high frequency of uncompetitive supply conditions provides considerable opportunity for a pivotal supplier to profitably increase price.

We cannot make inferences regarding market power solely from pivotal supplier data because it does not consider the contractual position of the supplier. Bilateral and other financial contract obligations can affect whether a supplier has the incentive to raise prices. For example, a small supplier selling energy solely in the real-time energy market may have a much greater incentive to exercise market power than a large supplier with substantial long-term sales contracts. We recommend that the "small fish" rule be eliminated because these small suppliers are sometimes pivotal, and because high offer prices are not necessary to ensure efficient pricing under tight conditions (see SOM Recommendation 2021-1).

It should be noted that the analysis above evaluates the structure of the entire ERCOT market. In general, local market power in smaller geographic areas of the power region that can become isolated by transmission constraints raise more substantial competitiveness concerns. As more fully discussed in Chapter IV, this local market power is addressed through: (a) structural tests that determine "non-competitive" constraints that can create local market power; and (b) the "mitigation" or application of limits on offer prices in these areas.

## B. Evaluation of Supplier Conduct

This subsection provides the results of our evaluation of actual conduct to assess whether market participants have attempted to exercise market power through physical or economic withholding. First, we examine unit deratings and forced outages to detect physical withholding, and then we review the "output gap" used to detect economic withholding.

In a single-price auction like the real-time energy market, suppliers may attempt to exercise market power by withholding resources. The purpose of withholding is to cause more expensive resources to set higher prices, allowing the supplier to profit from its other sales in the market. Because forward prices are highly correlated with spot prices, price increases in the real-time energy market can also increase a supplier's profits in the bilateral energy market. This strategy is profitable if the incremental profit exceeds the foregone profits from its withheld capacity.

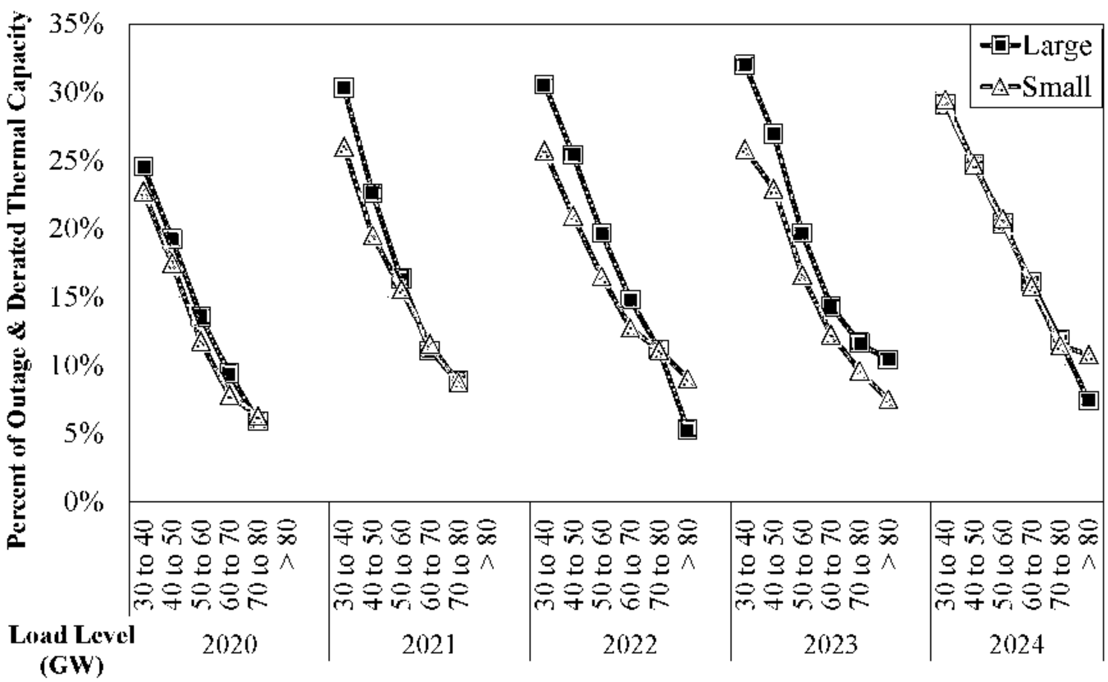
### 1. Evaluation of Potential Physical Withholding

Physical withholding occurs when a participant makes resources unavailable for dispatch that are otherwise physically capable of providing energy and are economic at market clearing prices. A plant operator can withhold either by derating a unit or declaring the unit as forced out of service. Because generator deratings and forced outages are unavoidable, the goal of the analysis in this subsection is to differentiate justifiable deratings and outages from physical withholding. We conduct a test for physical withholding by examining deratings and outage data to ascertain whether the data are correlated with conditions under which physical withholding would likely be most profitable.

The pivotal supplier results shown in Figure 61 indicates that the potential for market power abuse rises at higher net load levels, as the frequency of intervals in which suppliers are pivotal increases. Hence, if physical withholding is occurring, one would expect to see increased deratings and outages at the highest load levels. Conversely, because competitive prices increase as load increases, deratings and outages in a market performing competitively will tend to decrease as load approaches peak levels. Suppliers that lack market power will take actions to maximize the availability of their resources because their output is generally most profitable in peak periods.

Figure 62 shows the average aggregate planned, forced, and unreported outages as a percentage of total installed capacity for large and small suppliers under different real-time load levels. Portfolio size is important in determining whether suppliers have incentives to withhold available resources. Hence, we compare the patterns of outages and deratings of large and small suppliers. It is important to consider the aggregate number of outages due to the high frequency of pivotal supplier hours.

**Figure 62: Outages and Deratings by Load Level and Participant Size**




Wind, solar, and energy storage resources (ESRs) also are excluded from this analysis because of the high variation in the availability of these classes of resources. The large supplier category includes the four largest suppliers (DMEs) in ERCOT. The small supplier category includes the remaining suppliers.

Figure 62 confirms the pattern we have seen since 2018 that as demand for electricity increases, all market participants generally make slightly more capacity available to the market by scheduling planned outages during low load periods. The fact that available capacity tends to be higher under the highest load conditions is particularly notable because rising ambient temperatures generally cause thermal units' capability to fall.

Because small participants generally have less ability to physically withhold capacity to profitably exercise market power, the outage rates for small suppliers serve as a good benchmark for competitive behavior expected from the larger suppliers. Outage rates for large suppliers at all load levels modestly exceeded those for small suppliers but remained at levels that are small enough to raise no competitiveness concerns.

## 2. Evaluation of Potential Economic Withholding

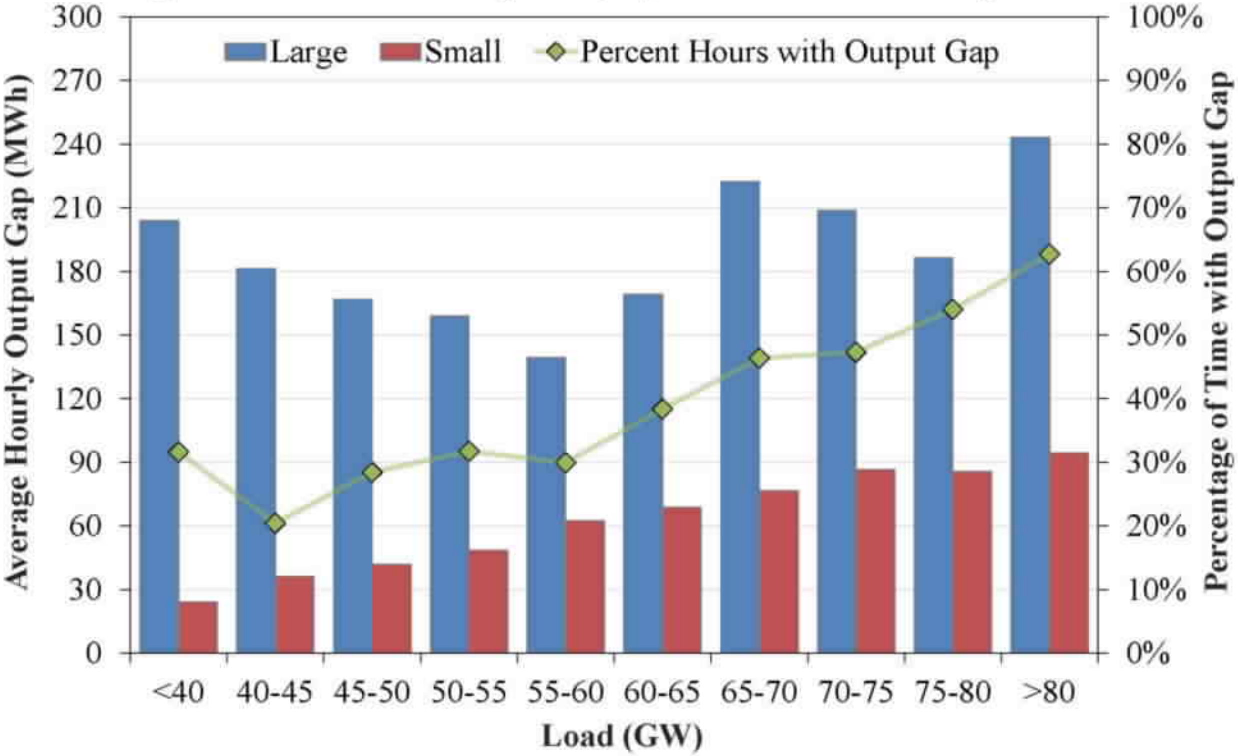
In this subsection, we evaluate potential economic withholding by calculating an "output gap". The output gap is the quantity of energy that is not being produced by online resources even though the output is economic to produce by a substantial margin given the real-time energy price. A participant can economically withhold resources, as measured by the output gap, by raising its energy offers for a resource to reduce its dispatch level.

Resources included in the output gap are those that are committed and producing at less than full output. Energy not produced from a committed resource is included in the output gap if the real-time energy price exceeds that unit's mitigated offer cap by at least $30 per MWh. The mitigated offer cap serves as a proxy for the marginal production cost of energy from that resource.

Figure 63 shows the average output gap levels, measured by the difference between a unit's operating level and the output level based on delivery over an hour had the unit been offered to the market based on a proxy for a competitive offer (i.e., the unit's mitigated offers), but with a few changes. We use generic costs instead of verifiable costs for quick-start units since verifiable costs may contain startup costs that are inappropriate for comparison here. In addition, fuel adders are removed since they represent fixed costs. Finally, we do include quick-start units if they were in quick-start mode and available for real-time dispatch. The information in Figure 63 reflects the average positive output gap by load level with the percentage of hours reflected in each load level category for reference.

In 2024, roughly 32% of the hours exhibited an output gap, indicating potential attempt to exercise market power through economic withholding. At higher load levels, an extremely small percentage of generating capacity exhibited an output gap for a large percentage of time. An even smaller percentage of generating capacity exhibited an output gap at lower load levels. These results show that potential economic withholding in the real-time energy market as low, but not trivial, in 2024. While the ERCOT market may have performed competitively in general, the level of market power and moderate evidence of potential economic withholding are cause for concern. Anticipated increase in system load over the coming years can result in more frequent structural market power and more incentive to exercise that market power.

Figure 63: Incremental Output Gap by Load Level and Participant Size




## C. Voluntary Mitigation Plans

The PUCT has discretion to approve VMPs filed by market participants.[71] Before September 1, 2023, a market participant's adherence to a PUCT-approved VMP constituted an absolute defense against an allegation of market power abuse with respect to behaviors addressed by the plan. However, House Bill 1500, which was passed during the 88th Legislative session and went in effect on September 1, 2023, modified the statutory requirements related to VMPs. Adherence to a VMP is no longer considered an absolute defense against allegations of market power abuse with respect to the behaviors addressed by the VMP; instead, adherence to a VMP must be considered in determining whether a violation occurred and, if so, the penalty to be assessed.[72]

Generation owners are often motivated to enter into VMPs, and the increased regulatory certainty afforded to a generation owner regarding its energy offers in the ERCOT real-time market must be balanced by appropriate protections against a potential abuse of market power in violation of Public Utility Regulatory Act (PURA) §39.157(a) and 16 TAC §25.503(g)(7). In

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71 PURA § 15.023(f).

72 *Id.* Also, the PUCT amended its rules to implement these statutory changes on April 25, 2024. *Review of Voluntary Mitigation Plan Requirements*, Docket No. 55948, Order (Apr. 25, 2024)

2023, Calpine, NRG, and Luminant had active and approved VMPs filed with the PUCT.[73] The PUCT modified these three VMPs on March 23, 2023 to address competitiveness concerns that the IMM raised in 2022 related to ERCOT's greatly increased procurement of Non-Spin Reserve Service (NSRS).[74] In February of 2024, NRG filed a letter with the PUCT expressing NRG's intent to exercise its right to terminate its VMP, effective March 1, 2024.[75]

The VMPs for Calpine and Luminant include provisions that specify competitive benchmarks for offers in both energy and reserves. Further, the provisions address different generation technologies and fuel types and also address on-line versus off-line states in consideration of competitive cost on which to base the offer cap. The IMM reviews the VMPs on a cycle and when significant changes to market rules may change the competitiveness of the market or one or more participants' degree of market power. Assessment and recommendations regarding VMP provisions are provided to PUCT staff.

VMPs should promote competitive outcomes and prevent abuse of market power through economic withholding in the ERCOT real-time energy market. The same restrictions are not required in forward energy markets (e.g., the ERCOT day-ahead market), but the prices in forward energy markets are informed by expectations for real-time energy prices (where mitigation is applied). The forward energy market is voluntary, and the market rules do not inhibit arbitrage between the forward energy market and the real-time energy market. Therefore, competitive outcomes in the real-time energy market serve to discipline the potential abuse of market power in the forward energy markets.

PURA defines market power abuses as "practices by persons possessing market power that are unreasonably discriminatory or tend to unreasonably restrict, impair, or reduce the level of competition."[76] The *exercise* of market power may not rise to the level of an *abuse* of market power if the actions in question do not unreasonably impair competition. Impairment of

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73 *See Petition of Calpine Corporation for Approval of Voluntary Mitigation Plan,* Docket No. 40545, Order (Mar. 28, 2013); *Request for Approval of a Voluntary Mitigation Plan for NRG Companies Pursuant to PURA § 15.023(f) and P.U.C. Subst. R. 25.504(e),* Docket No. 40488, Order (Jul. 13, 2012); *Request for Approval of an Amended Voluntary Mitigation Plan for NRG Companies,* Docket No. 42611, Order (Jul. 11, 2014); *PUCT Staff Request for Approval of a Voluntary Mitigation Plan for Luminant Energy Company, LLC under PURA §15.023(f) and 16 TAC §25.504(e),* Docket No. 49858, (Dec. 13, 2019).

74 *See Request for Approval of an Amended Voluntary Mitigation Plan for Luminant Energy Company LLC Pursuant to PURA § 15.023(f) and 16 TAC § 25.504(e),* Docket No. 54739 (Mar. 23, 2023); *Request for Ratification of PUCT Staff's Termination in Part of the Amended Voluntary Mitigation Plan for NRG Companies,* Docket No. 54740, Order (Mar. 23, 2023);*Request for Approval of an Amended Voluntary Mitigation Plan for Calpine Corporation Pursuant to PURA § 15.023(f) and 16 TAC § 25.504(e),* Docket 54741, Order (Mar. 23, 2023).

75 *Request for Ratification of PUCT Staff's Termination in Part of the Amended Voluntary Mitigation Plan for NRG Companies,* Docket No. 54740, NRG Notice Regarding Voluntary Mitigation Plan (Feb. 23, 2024).

76 PURA § 39.157(a).

competition would typically involve profitably raising prices materially above the competitive level for a significant period.

A key aspect in the VMPs that provided leverage in 2023 was the termination provisions. Each of the VMPs could be terminated by the Executive Director of the PUCT with three business days' notice, subject to ratification by the Commission.[77] Although the offer thresholds provided in the VMPs are intended to promote competitive market outcomes, the short-lead termination provision provides additional assurance that any unintended consequences associated with potential exercise of market power can be addressed in a timely manner.

## D. Market Power Mitigation

In situations where competition is not robust and suppliers have market power, it is necessary for an independent system operator to mitigate offers to prevent the offer prices from diverging substantially from competitive levels. ERCOT's real-time market includes a mechanism to mitigate offers for resources that may have local market power because they are required to manage a transmission constraint.

Mitigation applies whether the unit is self-committed or receives a Reliability Unit Commitment (RUC) instruction. Prior to 2021, ERCOT typically issued RUC instructions to resolve transmission constraints. However, starting in summer 2021, RUCs for system-wide capacity became common and continued through early 2023. When units that receive RUC instructions are required to resolve a non-competitive transmission constraint, they often are dispatched with their offer prices capped at mitigated levels in real-time. ERCOT's dispatch software includes an automatic, two-step mitigation process:

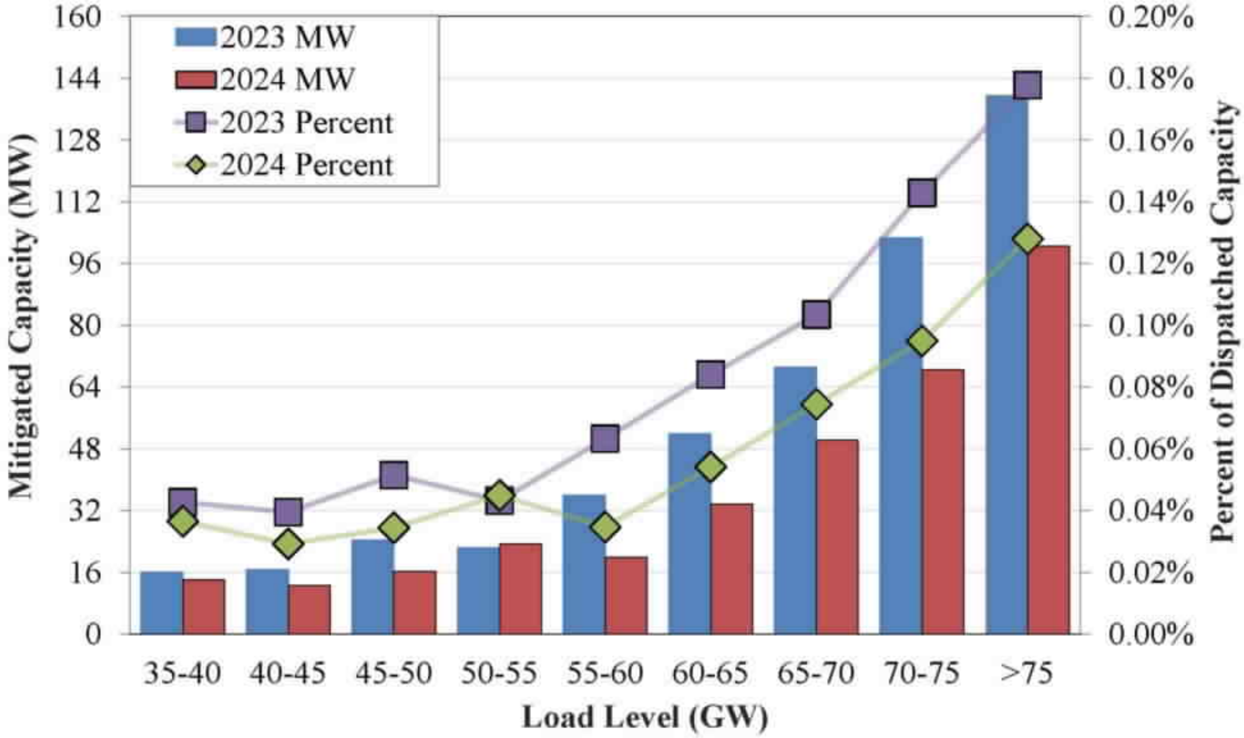
- The dispatch software calculates output levels (base points) and prices using the participants' offer curves considering only the "competitive" transmission constraints. The higher of a) resulting prices at each generator location; and b) the generator's mitigated offer cap is used to formulate the mitigated offer curve for the generator in the second step of the dispatch process.
- The dispatch software then uses the mitigated offer curve to determine the final dispatch levels and prices taking all transmission constraints into consideration.

This approach is intended to limit the ability of a generator to exercise local market power by raising its offer price to increase prices in a transmission constrained area. In this subsection, we analyze the amount of mitigation that occurred in 2024. The automatic mitigation under the two-step dispatch process only has the potential to have an effect when a non-competitive transmission constraint is active and binding in SCED. Figure 64 shows the average amount and

77 Further, Luminant's VMP will automatically terminate on the earlier of ERCOT's go-live date for Real-Time Co-Optimization (RTC), seven years after initial approval of the VMP, or the day Luminant's Installed Generation Capacity drops below five percent of the total ERCOT Installed Generation Capacity.

percentage of capacity that was mitigated at different load levels. The amount of energy that could be produced within one interval is deemed mitigated for the purposes of this analysis.

**Figure 64: Mitigated Capacity by Load Level**




The quantity of mitigation shown in Figure 64 is very low compared to the total quantity of capacity online. Additionally, the two-step process in ERCOT will sometimes mitigate conduct that is not significantly increasing prices and, therefore, cannot be argued to be a legitimate exercise of market power. Therefore, these results do not raise competitiveness concerns.

The extent of mitigation was less in 2024 compared to 2023. A large driver of this lies with two factors. First, 2024 exhibited less in terms of extreme weather conditions that drive higher load for shorter periods of time. Higher load levels can increase congestion which could trigger mitigation. Second, ERCOT improved its deployment of the ERCOT Contingency Reserve Service (ECRS) in 2024 which made more energy available to the real-time market, which could have reduced the incidence of congestion on non-competitive constraints and reduced the incidence of mitigation. In general, when resources are necessary to resolve a local constraint, it is more likely that the constraint will be deemed non-competitive and result in mitigation. Figure 64 also shows that mitigation tends to increase as load increases. This is also likely because higher loads can lead to more frequent non-competitive constraints binding into load pockets.

# APPENDIX

## INTRODUCTION

This Appendix provides supplemental analysis of certain topics raised in the main body of the Report. We present the methods and motivation for each of the analyses. However, our conclusions from these analyses and how they relate to the performance of the markets are discussed in the main body of the Report. In addition, the body of the Report includes a discussion of our recommendations to improve the design and competitiveness of the market.

# I. APPENDIX: STATISTICS AT A GLANCE

In this section of the Appendix, we provide supplemental analyses of 2024 prices and outcomes in ERCOT's real-time energy market. Table A1 is the annual aggregate costs of various ERCOT charges or payments in 2024, including ancillary services charges by type. This does not reflect the total cost of each ancillary service, as it only accounts for the net charges after self-arrangement. Also, for energy, we calculated the real-time energy value based on MWs generated rather than settlement data, as energy imbalance charges net out (plus RENA).

**Table A1: ERCOT 2024 Year at a Glance (Annual)**

| | Annual Total ($ Millions) |
|---|---|
| Energy | $14,640 |
| Regulation Up | $26 |
| Regulation Down | $14 |
| Responsive Reserve | $109 |
| Non-Spin | $161 |
| ECRS | $147 |
| CRR Auction Distribution | ($1,710) |
| Balancing Account Surplus | $239 |
| Emergency Response Service | $73 |
| Revenue Neutrality Uplift | $161 |
| AS Imbalance Uplift | ($8) |
| ERCOT Admin Fee | $292 |
| ERO Passthrough Fee | $28 |
| Firm Fuel Supply Service | $38 |
| Other Load Allocation | $9 |
| Net Cost of Electricity | $14,219 |

Table A2 presents the monthly aggregate costs of various ERCOT market settlement totals in 2024, including ancillary services costs by type.

**Table A2: Market at a Glance Monthly**

| | Monthly Totals ($ Millions) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sept | Oct | Nov | Dec |
| Energy | $1,542 | $485 | $795 | $932 | $1,867 | $1,444 | $1,121 | $2,093 | $1,129 | $1,120 | $1,133 | $978 |
| Regulation Up | $5 | $1 | $2 | $3 | $5 | $1 | $1 | $3 | $1 | $2 | $2 | $1 |
| Regulation Down | $4 | $1 | $1 | $2 | $2 | $1 | $1 | $1 | $0.5 | $1 | $0.4 | $0.5 |
| Responsive Reserve | $30 | $3 | $8 | $11 | $20 | $4 | $4 | $12 | $3 | $7 | $5 | $2 |
| Non-Spin | $30 | $3 | $10 | $14 | $72 | $8 | $2 | $4 | $2 | $6 | $5 | $4 |
| ERCOT Contingency Reserve Service | $25 | $3 | $8 | $11 | $48 | $15 | $5 | $17 | $3 | $6 | $3 | $1 |
| CRR Auction Distribution | ($126) | ($124) | ($151) | ($154) | ($158) | ($150) | ($151) | ($149) | ($131) | ($144) | ($133) | ($138) |
| Balancing Account Surplus | $40 | $12 | $21 | $6 | $19 | $30 | $25 | $28 | $17 | $4 | $25 | $13 |
| Emergency Response Service | - | - | - | $35 | - | $3 | - | - | - | $30 | | $4 |
| Revenue Neutrality Uplift | $11 | $8 | $20 | $13 | $27 | $9 | $9 | $10 | $17 | $9 | $10 | $18 |
| AS Imbalance Uplift | $1 | $0.2 | $1 | $2 | ($1) | $0.2 | $0.1 | ($0.3) | $0.4 | $1 | $1 | $2 |
| ERCOT Fee | $24 | $19 | $20 | $21 | $25 | $28 | $28 | $31 | $26 | $25 | $21 | $22 |
| ERO Passthrough Fee | $2 | $2 | $2 | $2 | $2 | $2 | $2 | $2 | $2 | $2 | $2 | $2 |
| Firm Fuel Supply Service | $8 | $7 | $4 | - | - | - | - | - | - | - | $7 | $12 |
| Other Load Allocation | $8 | $1 | - | ($1) | $0.2 | $0.1 | $0 | $1 | $0.1 | $0 | $0 | $0 |

# II. Appendix: Ancillary Services

In this section, we provide supplemental data related to the provision of ancillary services through the day-ahead market and the supplemental ancillary services market (SASM).

## A. Ancillary Services Provided in Real-Time

Figure A1 through Figure A5 break down the provision of each AS product by resource type. Notable trends include the following:

- Provision of RRS is dominated by ESRs and NCLRs
- The vast majority of the volume of regulation reserves is provided by ESRs
- ECRS is supplied by a combination of ESRs and gas peakers. However, duration requirements have constrained the share provided by ESRs.
- Most NSRS is provided by gas peakers. This shift began in 2022 following a sharp increase in NSRS procurement volumes, which led to greater reliance on offline units that can start within 30 minutes, primarily gas peakers.

**Figure A1: Responsive Reserve Providers, 2022-2024**

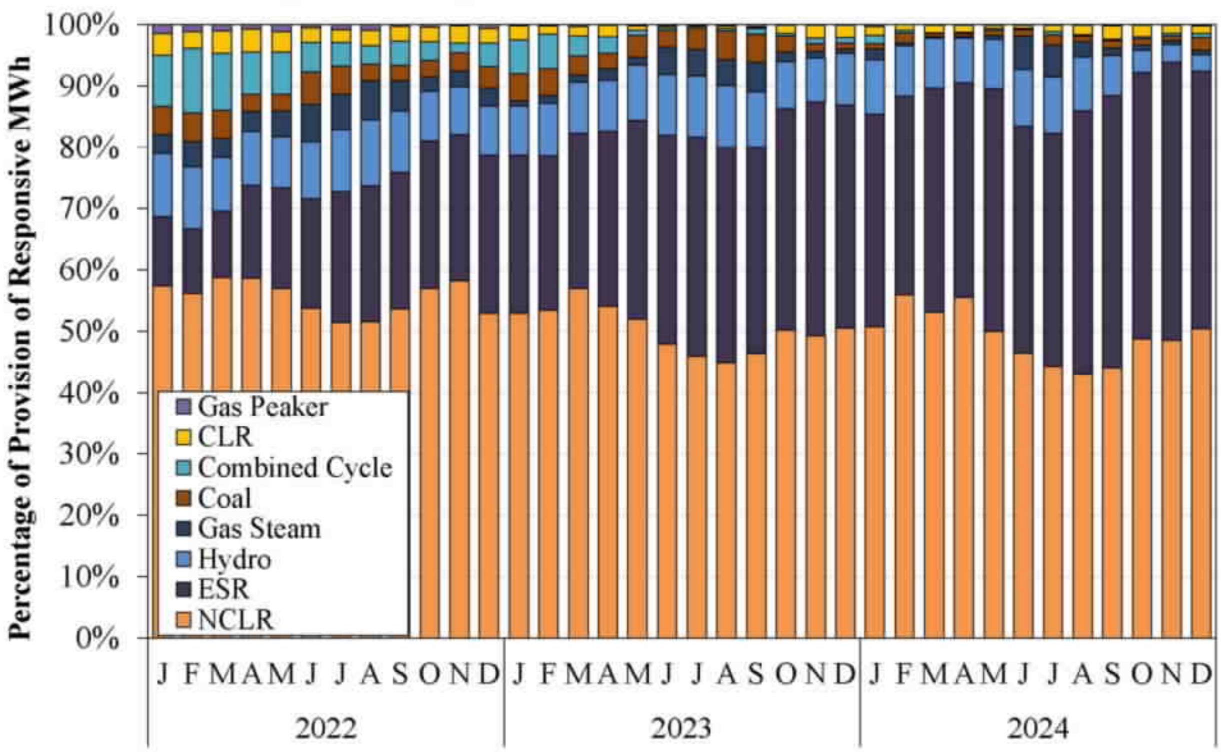


**Figure A2: ERCOT Contingency Reserve Service Providers, 2022-2024**

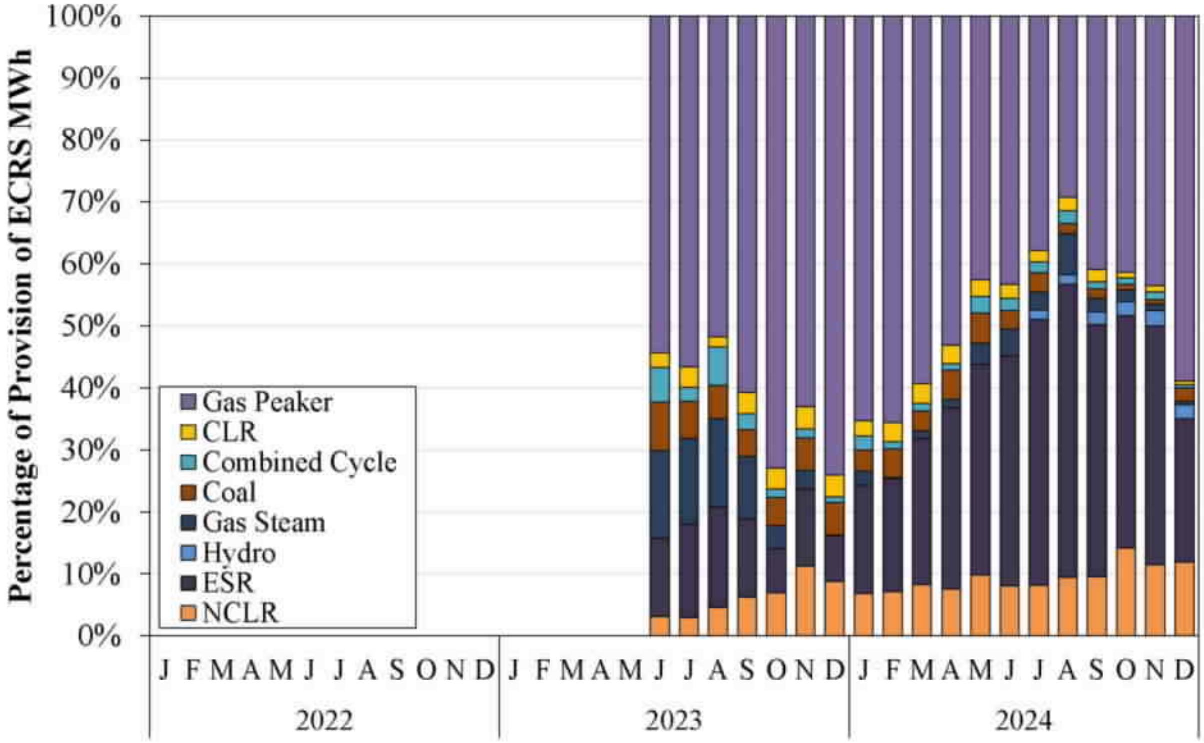



**Figure A3: Non-Spinning Reserve Providers, 2022-2024**

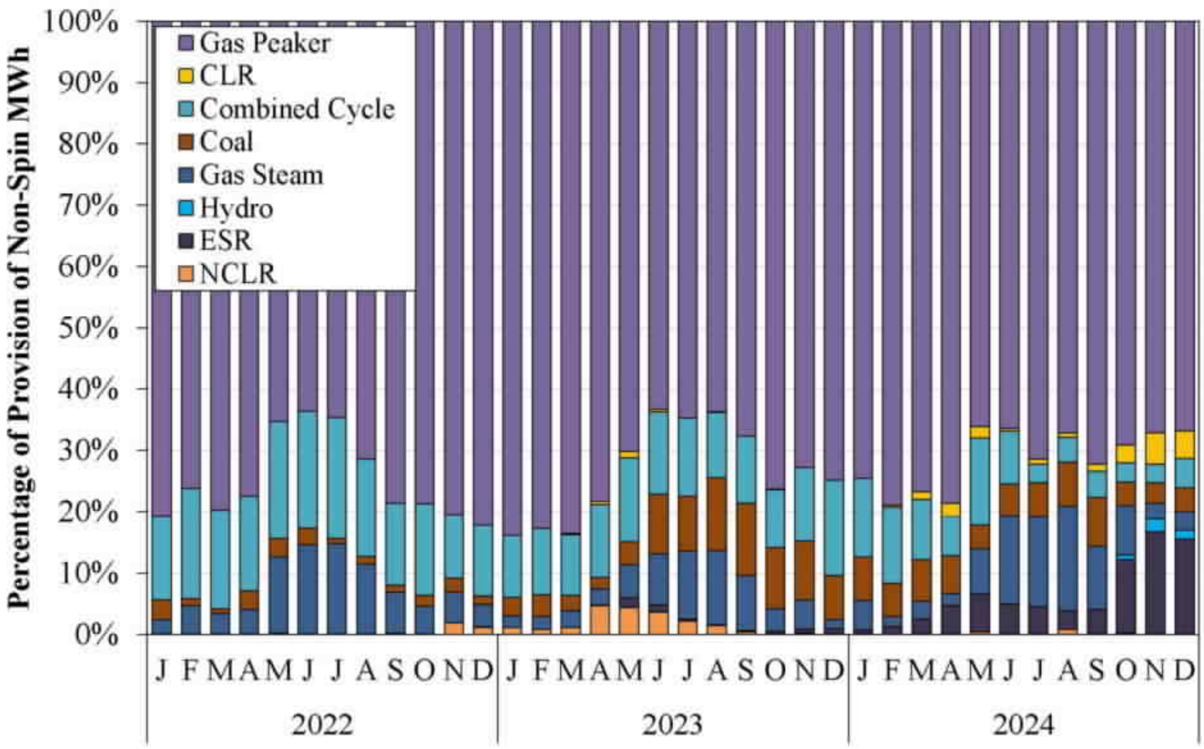


**Figure A4: Regulation Up Reserve Providers, 2022-2024**

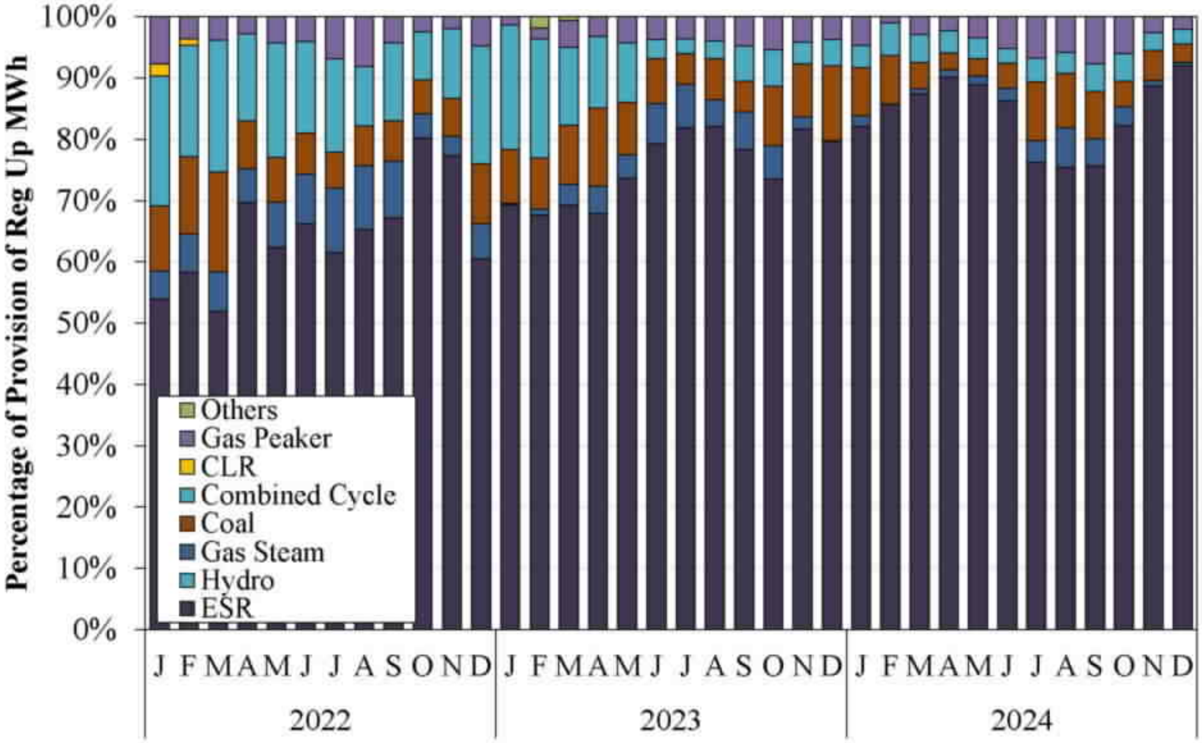
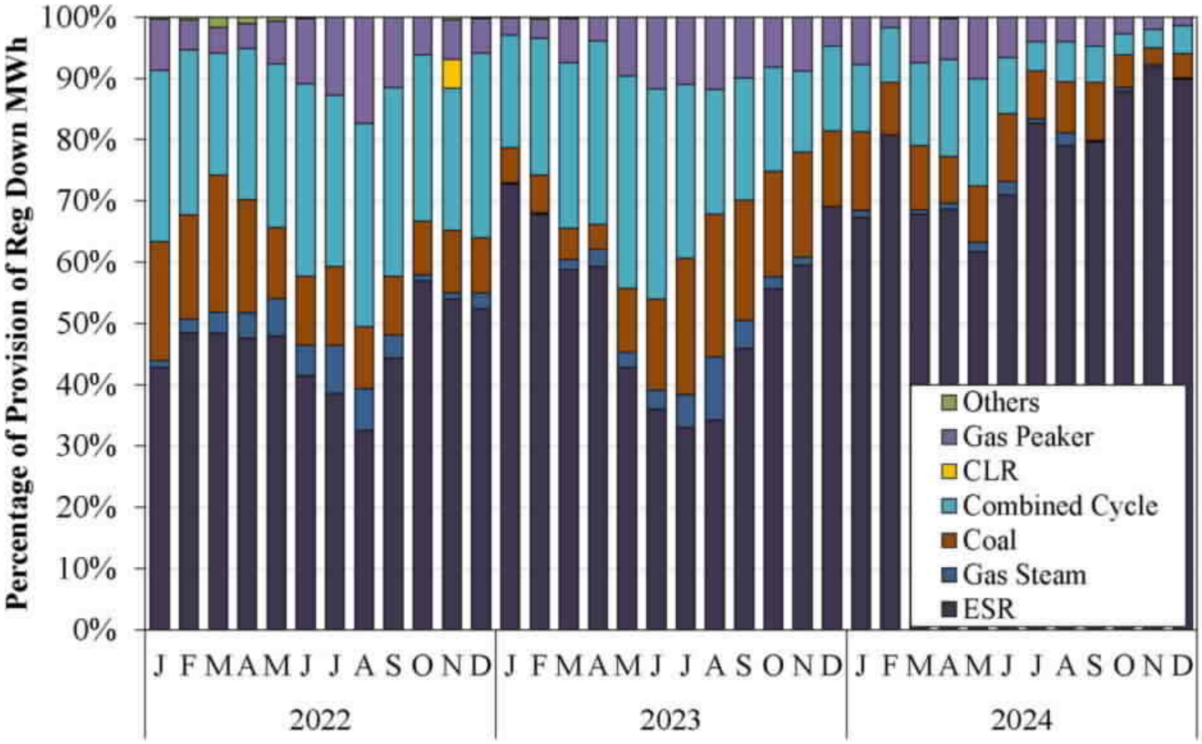



**Figure A5: Regulation Down Reserve Providers, 2022-2024**



## B. Supplemental Ancillary Services Market

Until the implementation of RTC, the ancillary service awards from the day-ahead market are physically binding in real-time on a QSE basis. That means that if an ancillary service is awarded to a resource in the day-ahead market, the QSE for that resource can move the responsibility to carry that award to any other qualified unit in its fleet in real-time, allowing the QSE to optimize which of its resources are providing energy versus ancillary services. While these choices are likely to be in the QSE's best interest, they are not likely to lead to the most economic provision of energy and ancillary services for the whole market. Further, QSEs without large resource portfolios still face greater risks than those with larger portfolios because they may need to procure replacement ancillary services through the SASM, where prices can be high and uncertain. This replacement risk is substantial. Clearing prices for ancillary services procured in the SASM are often three to four times greater than clearing prices from the day-ahead market.

The volume of reserves procured through the SASM for 2020-2024 is shown in Figure A6. SASMs were executed 102 times in 2024 to procure a total of more than 27,000 MW of operating reserves, more than three times the volume procured through SASMs in 2023, but still very low compared to the nearly 70 million service-hours set by the AS Plan.

**Figure A6: Ancillary Service Quantities Procured in SASM, 2020-2024**

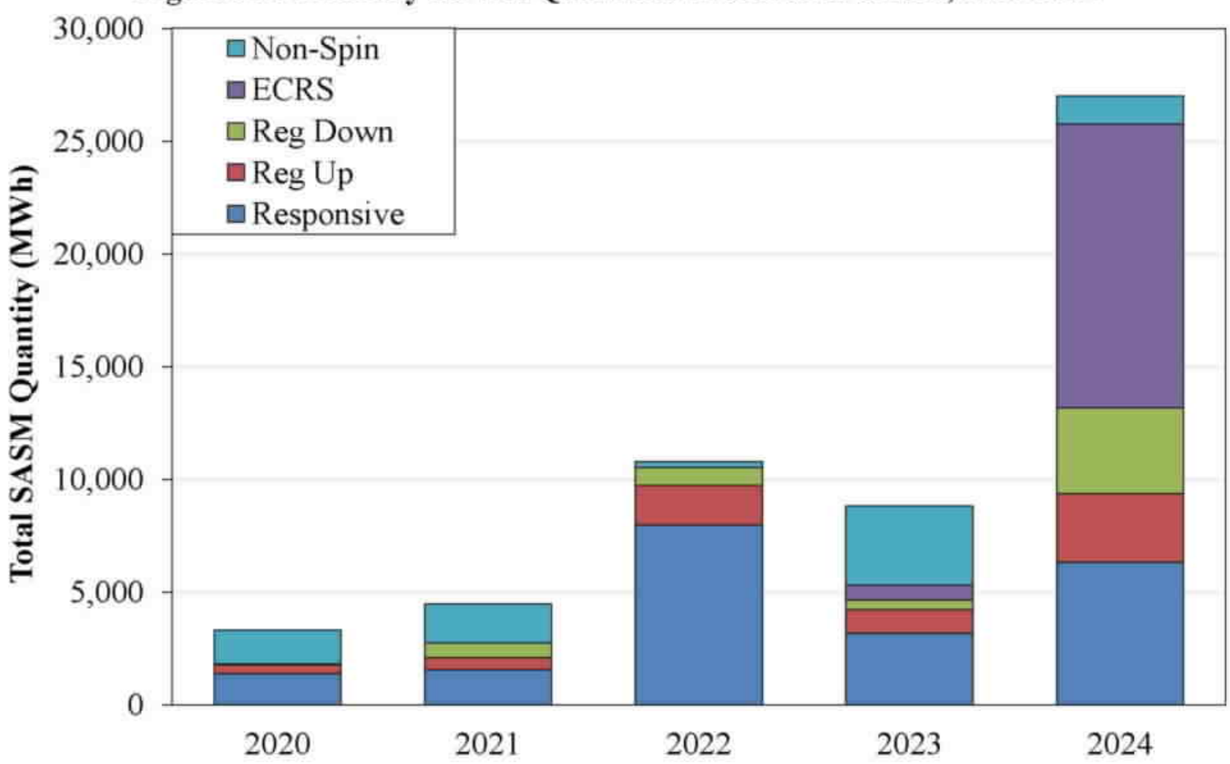
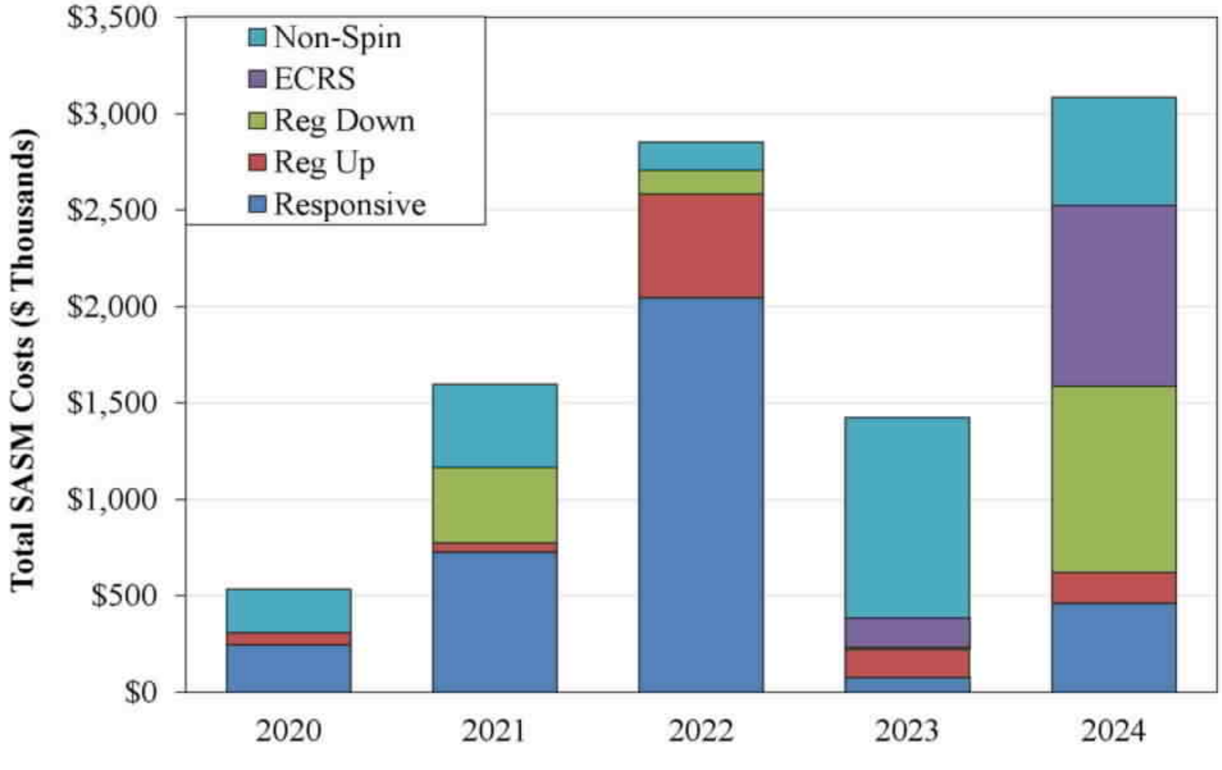



Figure A7 shows the average cost of the replacement ancillary services procured by SASM from 2020-2024. The total SASM costs across 2024 reached its peak since 2014, though only slightly higher than in 2022. SASM costs since 2021 have been substantially higher than they were from 2014-2020, which is a result of the large increases in operating reserves procured since 2021.

**Figure A7: Total Cost of Procured SASM Ancillary Services, 2020-2024**



# III. APPENDIX: DETAIL OF EXISTING VMPS

In 2023, three market participants had active VMPs. Each of these VMPs went through significant modifications regarding Non-Spin Reserve Service (NSRS) in March of 2023. Pursuant to those modifications, NRG's ancillary services offers are no longer covered by their VMP; Luminant has a $20 per MWh NSRS offer cap; and Calpine has a dynamic formula based on its offers for other ancillary services. NRG terminated their VMP as of March 1, 2024.[78]

## i. Calpine VMP

Calpine's VMP was initially approved in March of 2013.[79] Because its generation fleet consists entirely of natural gas fueled combined cycle units, the details of the Calpine plan are somewhat different than the others. Calpine may offer up to 10% of the dispatchable capacity of its portfolio at prices up to $500 per MWh. Additionally, Calpine may offer up to 5% of the dispatchable capacity of its portfolio at prices no higher than the system-wide offer cap. When approved, the amount of capacity covered by these provisions was approximately 500 MW.

In March of 2023, Calpine's VMP was amended to eliminate the provision allowing NSRS in the day-ahead market to be made up to and including the high system-wide offer cap.[80] A dynamic formula for NSRS offers was substituted for the eliminated provision.[81] The new formula is based on Calpine's offers for other ancillary services, recognizing that NSRS are of lower value to the ERCOT system than responsive reserve service, regulation up, or ECRS. Calpine's VMP remains in effect from the date it was approved by the PUCT until terminated by the Executive Director of the PUCT or Calpine.[82]

## ii. Luminant VMP

Luminant received approval from the PUCT for a new VMP in December 2019.[83] The PUCT terminated Luminant's previous VMP on April 9, 2018, as a result of its merger with Dynegy,

78 *Request for ratification of Commission Staff's Termination in Part of the Amended Voluntary Mitigation Plan for NRG Companies*, Docket No. 54740, (Feb. 23, 2024).

79 *Petition of Calpine Corporation for Approval of Voluntary Mitigation Plan*, Docket No. 40545, Order (Mar. 28, 2013).

80 *Request for Approval of an Amended Voluntary Mitigation Plan for Calpine Corporation Pursuant to PURA § 15.023(f) and 16 TAC § 25.504(e)*, Docket No. 54741, Order (Mar. 23, 2023).

81 *Id.*

82 *Id.*

83 *PUCT Staff Request for Approval of a Voluntary Mitigation Plan for Luminant Energy Company, LLC under PURA §15.023(f) and 16 TAC §25.504(e)*, Docket No. 49858, (Dec. 13, 2019).

Inc.[84] The new VMP provides for small amounts of capacity from non-quick start, non-combined cycle natural gas-fired units to be offered up to 12% of the dispatchable capacity for each unit at prices up to $500 per MWh, and up to 3% of the dispatchable capacity may be offered at prices up to and including the HCAP. When approved in late 2019, the amount of capacity covered by these provisions was less than 900 MW. In addition, the plan defines allowable limits for energy offers from Luminant's quick start combustion turbines.

Before March of 2023, Luminant's VMP provided that offers in the day-ahead market for ancillary services could be made up to and including the high system-wide offer cap. In March of 2023, Luminant's VMP was amended to place a cap on offers in the day-ahead market for NSRS of $20 per MWh for all resources.[85]

84 *See Application of Luminant Power Generation LLC, Big Brown Power Company LLC, Comanche Peak Power Company LLC, La Frontera Holdings LLC, Oak Grove Management Company LLC, and Sandow Power Company Under Section § 39.158 of the Public Utility Regulatory Act,* Docket No. 47801 (Nov. 22, 2017). On April 9, 2018, Luminant filed a letter with the PUCT terminating its VMP upon closing of the proposed transaction approved by the PUCT in Finding of Fact No. 36 of the Order in Docket No. 47801. *See also Request for Approval of a Voluntary Mitigation Plan for Luminant Companies Pursuant to PURA § 15.023(f) and P.U.C. Subst R. 25.504(e),* Docket No. 44635, Order Approving VMP Settlement (May 22, 2015).

85 *Request for Approval of an Amended Voluntary Mitigation Plan for Luminant Energy Company LLC Pursuant to PURA § 15.023(f) and 16 TAC § 25.504(e),* Docket No. 54739 (Mar. 23, 2023).