Filing Receipt

Filing Date - 2024-06-20 01:40:22 PM

Control Number - 56211

Item Number - 369

SOAH DOCKET NO. 473-24-13232
PUC DOCKET NO. 56211

APPLICATION OF CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC FOR AUTHORITY TO CHANGE RATES	**§ § §**	**BEFORE THE STATE OFFICE OF ADMINISTRATIVE HEARINGS**

WORKPAPERS TO THE

DIRECT TESTIMONY AND EXHIBITS OF JEFFRY POLLOCK

ON BEHALF OF

TEXAS INDUSTRIAL ENERGY CONSUMERS

June 20, 2024

6.1.2.2 CONSTRUCTION SERVICES POLICY AND CHARGES

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SECTION 1: INTRODUCTION

Company provides Construction Services to Retail Customers in accordance with the terms and conditions in this Construction Services policy and the most recent versions of the Company's Service Standards and such other specification documents designated by Company.

The terms and conditions contained in Chapters 3, 4 and 5 of this Tariff, including the Facilities Extension Policy in Section 5.7, are also a part of this Construction Services policy.

Construction Services may be provided by Company at the request of Retail Customer or its Competitive Retailer or when otherwise deemed necessary by Company in accordance with Good Utility Practice. In some cases, execution of an agreement and payment of charges by the Retail Customer is required for the Company's provision of Construction Services.

Section 6.3 of this Tariff sets out the various forms of agreements for different types of Construction Services.

Discretionary charges for Construction Services are on an "As Calculated" basis unless otherwise stated in this Tariff. In addition, payments in the form of a nonrefundable contribution in aid of construction (CIAC) or an advance for construction may be required from the entity requesting Construction Service prior to commencement of construction.

SECTION 2: FACILITY EXTENSIONS TO PERMANENT RETAIL CUSTOMER ELECTRICAL INSTALLATIONS

Subsection 2.1 - Introduction

Permanent Retail Customer Electrical Installations. Company is responsible for the construction, extension, upgrade and alteration of its Delivery System necessary to connect permanent Retail Customer Electrical Installations to the Delivery System (collectively, Facility Extensions). For purposes of this Construction Services Policy, a Retail Customer's Electrical Installation is considered permanent if, in Company's determination, it is or will be used in a manner which provides the Company a reasonable return on the capital investment required to serve the Retail Customer for a time period approximately equal to the life of the Company's installed service facilities.

Standard Facilities. The Company's standard Delivery System facilities for Facility Extensions to permanent Retail Customer Electrical Installations consist of wood poles and overhead circuits and equipment to deliver Electric Power and Energy from one single-phase or three-phase source to Retail Customer at one Point of Delivery, with one Standard Meter and at one of the Company's standard Distribution Voltages described in Section 6.2.2 of this Tariff (collectively, Standard Facilities).

Non-Standard Facilities. Non-standard facilities include without limitation Transmission Voltage Delivery System facilities; Delivery System facilities for providing a two-way feed, redundant circuits, or Delivery Service at non-standard Distribution Voltages or through more than one Point of Delivery; Delivery System facilities for providing Delivery Service over poles other than wood poles; and underground Delivery System facilities (collectively, Non-Standard Facilities); provided, however, that underground Delivery System facilities will not be considered Non-Standard Facilities in certain locations within Company's Service Territory where the Company determines, for engineering or economic reasons, that underground facilities constitute Standard Facilities. A Retail Customer has the option to request and pay for the installation of Non-Standard Facilities for Facility Extensions. All Retail Customer requests for Non-Standard Facilities shall be subject to Section 5.7.5 of the Tariff.

Point of Delivery. The Point of Delivery and construction specifications for all Facility Extensions are determined by the Company.

Costs. Facility Extensions are normally done at no cost to Retail Customer except where the cost of the requested Facility Extension exceeds the Standard Allowance stated in this Construction Services Policy or where the Retail Customer requests the use of Non-Standard Facilities for the Facility Extension. In those exception cases, Retail Customer must execute an appropriate agreement in the form set out in Section 6.3 of this Tariff and pay a nonrefundable CIAC to Company prior to commencement of any Construction Services in an amount determined by Company equal to the estimated capital cost Company will incur to complete the Facility Extension (including the cost to procure and install any Non-Standard

Facilities requested by Retail Customer) minus the amount of the Standard Allowance for which the Retail Customer may be eligible under this Construction Services Policy. In addition, Retail Customer bears the cost of (1) obtaining easements and rights-of-way for the Facility Extension in instances where easements and/or rights-of-way have not been granted to the Company; (2) any "ball markers" required by the Federal Aviation Administration to be placed on an overhead Facility Extension; (3) any tree trimming and ground clearing requirements for which Retail Customer is responsible pursuant to subsection 2.2 of this Construction Services Policy; and (4) any applicable discretionary charges in Section 6.1.2.3.1 of this Tariff. Retail Customers requesting special construction, for aesthetic considerations, clearance of obstructions, or service to a non-standard Point of Delivery, must reimburse the Company for the difference in cost between the standard service arrangement and the requested special construction or routing.

Subsection 2.2 - Standard Allowance for Overhead Facility Extensions

Except as otherwise stated in Section 2 of this Construction Services Policy, the Company will construct a Facility Extension to connect a permanent Retail Customer Electrical Installation to Company's Delivery System at Distribution Voltages using Standard Facilities without charge to the Retail Customer for a distance not to exceed 1,000 feet for three phase service and 2,000 feet for single phase service (the Standard Allowance) measured from the nearest existing Delivery System facility of suitable voltage, phase and capacity (an Existing Facility) to the Point of Delivery, provided that these standard allowance distances apply only if the Facility Extension (1) is entirely constructed on a public right-of-way or a dedicated easement, or (2) if not entirely constructed on a public right-of-way or dedicated easement, does not require the construction of more than three poles on private property. These distances are measured as actual route distances between the Existing Facility and the Point of Delivery rather than straight-line distances. The Company determines the Point of Delivery to all Retail Customers as well as the standard routing for Company Delivery System facilities required to provide Delivery Service to the Point of Delivery.

Costs associated with Facility Extensions in excess of the Standard Allowance are at Retail Customer expense, as are costs associated with increasing the capacity of existing lines along the route of the Facility Extension and costs associated with constructing Facility Extensions over or around any natural or man-made obstacle.

The Standard Allowance is unavailable, and will not be used to offset a Retail Customer's CIAC requirement, for the following types of Facility Extensions: (1) Facility Extensions of the Transmission Voltage Delivery System; (2) Facility Extensions to non-permanent Retail Customer Electrical Installations; (3) Facility Extensions for the provision of Premium Service to Retail Customers; and (4) Facility Extensions solely for the interconnection of distributed generation.

Ground Clearing

The Retail Customer is required to clear the ground of all trees, stumps, brush, or debris along the route of the proposed extension to a width specified by the Company. However, where ground clearing is required on third party property, the Company may require that such work be done by the Company at Retail Customer expense. The Company performs the remaining tree trimming within the limits of the free distance. If the cost of the trimming exceeds 25 percent of the free distance line cost, the Retail Customer bears the remainder of the trimming cost. Transformers, meters, and service drops are not included in the line cost. Any costs for the purchase of rights-of-way for service extensions (including compensation paid to landowners granting said rights-of-way) shall be borne by the Retail Customer.

Area Development Plan

Service facilities may also be extended at Company expense provided the facilities are required for increased reliability, service continuity, or development of the Company's distribution system. In conjunction with the installation of such facilities, the Company may extend service from these facilities to Retail Customers without charge in accordance with the appropriate line extension plan.

Subsection 2.3- Transmission Voltage Facility Extensions

A Retail Customer whose load is of such magnitude or of such unusual characteristics that it cannot otherwise be economically served from Company's Distribution Voltage system, as determined by Company, must receive Delivery Service from the Company's Transmission Voltage system. The Retail Customer is responsible for all Facility Extension costs and (unless otherwise agreed by Company) for constructing, installing, operating and maintaining a substation at the Point of Delivery and all substation equipment, in accordance with the Company's specifications, including the most recent versions of Company's "Specification for Customer-Owned 138 kV Substation Design" and "Specification for Remote Telemetry of a Customer Owned Facility, both initially and from time to time thereafter, whenever changes in the Company's transmission system (including the transmission system's monitoring and protection devices) require such changes in the substation in order to maintain its compatibility with the Company's transmission system. The Retail Customer must also at all times comply with Company's "Transmission & Substation Outage and Clearance Coordination Procedures" (as may be amended from time to time) and the requirements in Section 5.5.2 and 5.5.5 of this Tariff.

(b) Retail Customers that do not have at least 2 CP kVA will be billed by estimating the Retail Customer's 4 CP kVA demand by applying a class coincidence factor to the Retail Customer's NCP kVA, using the formula:

Estimated 4 CP kVA = (NCP kVA * TCCF)

Where:

NCP kVA is the highest 15-minute integrated demand of an individual Retail Customer served at transmission voltage during the month; and

TCCF is the transmission class coincidence factor for the months June, July, August, and September calculated from the Company's most recent general rate case proceeding using the following formula:

$$TCCF = \frac{\sum \text{Class } CP_1 \text{ kVA for June, July, August, September}}{\sum \text{Class NCP kVA for June, July, August, September}} = \cancel{0.784009}\ \underline{0.873222}$$

Where:

Class CP kVA is the transmission voltage rate class' 15-minute demand at the time of the ERCOT CP and Class NCP kVA is the transmission voltage class' maximum 15-minute demand during a month.

OTHER PROVISIONS

Type of Service. The standard Delivery Service under this Rate Schedule will be three-phase, 60 hertz, at the Company's standard Transmission Voltage levels described in Section 6.2.2 of this Tariff and in the Service Standards.

Metering Equipment. Delivery Service under this Rate Schedule will be metered using Company's Standard Meter provided for this type of Delivery Service. Any other metering option(s) requested by Retail Customer will be provided at an additional charge and/or will be provided by a Meter Owner other than the Company pursuant to Applicable Legal Authorities. The Company may install remote metering equipment to obtain information with which to determine the amount of the monthly bill. Retail Customer may have metering instruments installed to check the service supplied under this Rate Schedule in accordance with the provisions of the Tariff.

Construction Services. Where Construction Services are required to initiate Delivery Service under this Rate Schedule, additional charges and special contract arrangements may be required prior to Delivery Service being furnished, pursuant to the Company's Construction Services Policy in Section 6.1.2.2 of this Tariff.

Customer Load Study Charge. Company may conduct a load study for Retail Customers requesting Delivery Service under this Rate Schedule for a new load or load addition of 10 MW or more, and Company will charge, and Retail Customer must pay, an additional charge of $50,000.00 for the load study. The Company will waive this load study requirement and study fee for new loads and load additions of less than 10 MW, unless Company or ERCOT determines that a load study is required prior to connecting the new or additional load of less than 10 MW to the Transmission Voltage System. Additionally, if Company or ERCOT require a stability study to be performed, an addional charge of $50,000.00 will be applied to Retail Customer, for a total of $100,000.00.

Retail Customer Responsibilities. The Retail Customer shall own, operate, and maintain all facilities (except Company owned Billing Meter) necessary to receive three-phase, 60 hertz alternating current service at 60,000 volts or higher. Each Retail Customer served at Transmission Voltage shall comply with Company's operating requirements for transmission customers.

Sub-Metering. The Electric Power and Energy delivered under this Rate Schedule may not be re-metered or sub-metered by the Retail Customer for resale or sharing except pursuant to lawful sub-metering regulations of Applicable Legal Authorities.

On-Site Generation. If Retail Customer taking Delivery Service under this Rate Schedule has on-site electric generating capacity installed, additional contract arrangements may be required pursuant to section 5 of the Company's Construction Services Policy in Section 6.1.2.2 of this Tariff if less than 10 MW or pursuant to ERCOT guidelines and procedures if 10 MW or greater.

Municipal Account Franchise Credit. A credit equal to the amount of franchise fees included in the Transmission and Distribution Charges will be applied to municipal accounts receiving service within the incorporated limits of such municipality which imposes a municipal franchise fee upon the Company based on the kWh delivered within that municipality and who have signed an appropriate Franchise Agreement.

Adjustment To The Charges Applied To Retail Customer's Demand Measurement. If data to determine the Retail Customer's *Demand Measurement* becomes no longer available, the Company will determine a *Conversion Factor* which will be used as an adjustment to all per unit charges that will then be applied to the *New Demand Measurement*. *Demand Measurement* shall include the Billing kVA, the 4 CP kVA, NCP kVA or any other demand measurement required for billing under this rate schedule or any applicable rider(s) or any other applicable schedule(s). *New Demand Measurement* shall be the billing determinants which replace the *Demand Measurement*. The *Conversion Factor* will apply to unit prices per kVA such that when applied to the *New Demand Measurement*, the revenue derived by the Company under demand based charges shall be unaffected by such lack of data.

This adjustment may become necessary because of changes in metering capabilities, such as, meters that record and /or measure kW with no ability to determine kVA or meters which meter data in intervals other than 15 minutes. This adjustment also may become necessary due to changes in rules, laws, procedures other directives which might dictate or recommend that electric power, electric power related transactions, wire charges, nonbypassable charges and/or other transactions measure demand in a way that is inconsistent with the definitions and procedures stated in the Company's Tariff. This adjustment is applicable not only in the instances enumerated above but also for any and all other changes in *Demand Measurement* which would prevent the Company from obtaining the necessary data to determine the kVA quantities defined in this rate schedule, applicable riders and other applicable schedules.

The Conversion Factor shall render the Company revenue neutral to any change in *Demand Measurement* as described above.

Metering Adjustment. The Company may at its option measure service on the low voltage side of the Retail Customer's transformers in which event the kVA and kWh recorded by the Billing Meter will be adjusted to compensate for transformer losses on the basis of data furnished by the manufacturer of the Retail Customer's transformers. When the manufacturer is unable to supply the necessary data the adjustment will be based on tests conducted by the Company on the Retail Customer's transformers.

NOTICE
This Rate Schedule is subject to the Company's Tariff and Applicable Legal Authorities.

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
PUC DOCKET NO. 56211
SOAH DOCKET NO. 473-24-13232

TEXAS INDUSTRIAL ENERGY CONSUMERS
REQUEST NO.: TIEC-RFI04-02

QUESTION:

Please explain why CEHE' s proposed Load Study Charge is different from the load study fees currently charged by ERCOT.

ANSWER:

Large customer load studies are performed by transmission service providers and not ERCOT, and the Load Study Charge is not a pass-through charge from ERCOT. Rather, CenterPoint Houston's proposed Load Study Charge is designed to compensate CenterPoint Houston for the reasonable expenses it incurs when preparing load studies for large customers.

SPONSOR:
Harris, Rina; Mercado, David L;

RESPONSIVE DOCUMENTS:
None

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
PUC DOCKET NO. 56211
SOAH DOCKET NO. 473-24-13232

TEXAS INDUSTRIAL ENERGY CONSUMERS
REQUEST NO.: TIEC-RFI04-03

QUESTION:

Please provide any examples of similar load and stability study fees currently charged by any utility in ERCOT.

ANSWER:

CenterPoint Houston does not have any information responsive to this request.

SPONSOR:
Rina Harris/David Mercado

RESPONSIVE DOCUMENTS:
None

non-residential purposes at primary distribution voltage levels of between 12 and 60kV. The rate schedule sets forth the Monthly Rate (composed of the Customer Charge, the Metering Charge, the Distribution System Charge and Transmission System Charge), the service riders that may apply to the rate schedule, the method for determining the customer's billing demand, and the Company's general terms of service under this rate schedule.

Q. PLEASE DESCRIBE ANY PROPOSED CHANGES TO THE DELIVERY SYSTEM CHARGES IN THE PRIMARY SERVICE RATE SCHEDULE.

A. CenterPoint Houston is proposing to update the delivery system charges in this rate schedule to reflect the revenue requirement by function as determined by the Proposed CCOSS.

Q. PLEASE DESCRIBE THE TRANSMISSION SERVICE RATE SCHEDULE.

A. This rate schedule is available to retail customers requesting delivery service for non-residential purposes at transmission voltage levels (greater than 60kV). The rate schedule sets forth the Monthly Rate (composed of the Customer Charge, the Metering Charge, the Distribution System Charge and Transmission System Charge), the service riders that may apply to the rate schedule, the method for determining the customer's billing demand, and the Company's general terms of service under this rate schedule.

Q. PLEASE DESCRIBE ANY PROPOSED CHANGES TO THE TRANSMISSION SERVICE RATE SCHEDULE.

A. CenterPoint Houston is proposing to update the delivery system charges in this rate schedule to reflect the revenue requirement by function as determined in the

Proposed CCOSS. Additionally, the Company is proposing to add language to the Transmission Service Rate Schedule to include a Load Study Charge for customers requesting delivery service under this Rate Schedule for a new or added load of 10 MW or more.

Q. WHY IS CENTERPOINT HOUSTON IMPLEMENTING A CHARGE FOR LOAD STUDIES OVER 10MW?

A. CenterPoint Energy saw a large increase in load customer requests in 2023. In addition, the sizes of many of the load customer requests were at unprecedented sizes which increases the study complexity greatly as transmission upgrades are much more likely. CenterPoint Energy already charges a fee for generator interconnection studies which require similar studies be performed. CenterPoint Houston has proposed the Load Study Charge to ensure all customers requesting studies are treated equally, regardless of whether they are wholesale customers like generators or retail customers. The charge for load customer studies will also aid in our effort to weed out customers requesting a Load Study that do not have serious plans to start their project.

Q. WHAT WILL CENTERPOINT HOUSTON CHARGE CUSTOMERS FOR A LOAD STUDY?

A. CenterPoint Houston charges a $50,000 baseline fee to conduct a load study. If CenterPoint Houston and/or ERCOT require a stability analysis, an additional $50,000 fee applies.

Q. HOW WAS THE $50,000 MINIMUM CHARGE DETERMINED?

A. The Company used the flat fee already charged for generator full interconnection study ("FIS") of $100,000. The FIS consists of four component studies: a steady-state study, short circuit study, a stability study, and a facility study. The stability study, which is not typically required for load studies, takes about as much time to complete as the other three FIS components combined. Consequently, CenterPoint has proposed to set the Load Study fee at $50,000 unless a stability study is required, in which case the Company would charge the customer an additional $50,000.

Q. WILL THE LOAD STUDY CHARGE BE REFUNDABLE?

A. No. The Company does not intend to refund the fee for customers who ultimately build or decide not to build their facilities.

Q. PLEASE DESCRIBE THE STREET LIGHTING SERVICE ("SLS") WITHIN THE LIGHTING SERVICES RATE SCHEDULE.

A. SLS is available to cities, governmental agencies, real estate developers, and other groups requesting the installation of street lighting. SLS provides for the installation, ownership, and maintenance of street light systems and fixtures, which may be affixed to existing distribution poles, if available, or to ornamental poles specifically installed by the Company for the street light fixtures (referred to as "ornamental standards" in the SLS rate schedule), and the delivery of electric power and energy to such fixtures on an unmetered basis. The majority of the cost for providing this service are CenterPoint Houston's installation costs of the systems, i.e., capital investment, and maintenance expenses associated with the specific lighting fixture. This rate schedule contains provisions governing the terms of service and the type of street lighting systems available, the Monthly Rate

2023 Regional Transmission Plan

Executive Summary

The 2023 Regional Transmission Plan (RTP) is the result of a coordinated planning process performed by ERCOT Grid Planning with extensive review and input by NERC-registered Transmission Planners (TPs), Transmission Owners (TOs), and other stakeholders. The 2023 RTP addresses ERCOT System transmission needs for years 2025 through 2029. This report documents the results of the assessment, in part, to comply with the requirements of NERC Reliability Standards, ERCOT Protocols, and the ERCOT Planning Guide.

The reliability analysis was performed over a six-year planning horizon; years one through five representing the near-term horizon and year six representing the long-term horizon. The 2023 RTP assessed ERCOT's steady-state transmission needs under summer peak and off-peak conditions. In addition to the seasonal variations, the 2023 RTP also included various sensitivities to address uncertainty involved in the transmission planning process. The reliability analysis in the 2023 RTP included:

- Steady-state contingency analysis to identify criteria violations based on NERC Reliability Standards and ERCOT planning criteria.
- Short-circuit analysis to identify over-dutied circuit breakers in the near-term planning horizon.
- Cascading analysis to identify potential system cascading conditions.

Following the reliability assessment, ERCOT, in collaboration with TPs, developed Corrective Action Plans (CAPs) to address the reliability criteria violations identified in this assessment. These plans included, but were not limited to, upgrades or addition of new transmission facilities and new Constraint Management Plans.

The ERCOT grid is experiencing rapid changes, including trends of notable growth in demand and penetrations of intermittent Generation Resources. On the demand side, ERCOT set the current all-time peak demand record of 85,508 MW on August 10, 2023. For comparison, the highest peak demand record that had been set in 2022 was 80,148 MW. This trend of increased demand is expected to continue due to factors including the further electrification of the oil and gas processes in the Permian Basin and continued interest in connecting large loads to the system. Additional adoption of rooftop solar and electric vehicles is also projected. On the generation side, ERCOT set a new wind penetration record of 69.15% in April 2022 and a new solar penetration record of 32.93% in April 2023.[1] With the retirement of conventional generation continuing and the new and planned Generation Resources being mostly solar and battery energy storage, these rapid changes to the system will continue to bring additional challenges to the grid.

[1] https://www.ercot.com/files/docs/2022/02/08/ERCOT_Fact_Sheet.pdf

Consistent with the 2021 and 2022 RTPs, ERCOT determined that the demand forecast provided by the IHS Markit study[2] represents the most credible, currently available estimate of future electricity demand in the Permian Basin region for use in the 2023 RTP. Since the completion of the IHS Markit demand forecast in the first quarter of 2020, there have been a significant number of customer-specific requests for new electric service in the Permian Basin region, including in and around the Stanton Loop area. The requests in this area include new operations as well as electrification of existing "off-grid" operations. Those additional loads in and around the Stanton Loop area were incorporated in the 2023 RTP with input from the Transmission Service Providers (TSPs) in the region. ERCOT used the 2022 S&P Global Commodity Insights (formerly IHS Markit) Permian Basin load forecast[3] as a reference to verify the additional Stanton Loop area load incorporated (around 1,300 MW for year 2029) in the 2023 RTP on top of the 2019 IHS Markit load forecast.

The rapid growth of wind, solar, and energy storage resources, coupled with increased coal and gas generator retirements, resulted in increased reliance on intermittent, renewable generation to meet the higher system demand, which reduced the flexibility of resolving thermal overloads using generation re-dispatch and curtailment. Since renewable generation is typically located farther from the load centers, the 2023 RTP analysis found various major transmission pathways from the renewable-rich regions to the load centers needed upgrades to existing transmission facilities and/or additional new transmission pathways. The 2023 RTP identified the need for additional 345-kV import paths from South Texas to Central Texas, approximately 350 circuit miles of 345-kV line upgrade along the import path to Venus Switch towards the Dallas/Fort Worth metroplex from Lake Creek SES and Jewett, and 345-kV upgrades and additions along the southwest Houston corridor. Detailed findings of the 2023 RTP reliability analysis can be found in section 3 of this report.

Overall, 173 reliability projects were identified in the 2023 RTP to address all the reliability violations compared with 89 projects in the 2022 RTP, 67 projects in the 2021 RTP, and 50 projects in the 2020 RTP, which emphasizes the transmission challenges associated with the rapidly changing grid.

The majority of planned improvements identified in the 2023 RTP are 138-kV and 345-kV system upgrades. The projects identified as 345-kV upgrades consist of new substations, transmission line additions, upgrades and rebuilds, new 345/138-kV transformers, existing 345/138-kV transformer upgrades, and reactor additions.

ERCOT identified the following noteworthy reliability projects in the 2023 RTP:

- Faraday to Lamesa to Clearfork to Riverton 345-kV double-circuit line addition in Borden, Dawson, Andrews, Winkler, Loving, and Reeves Counties. This project was also identified as the Stage 5 transmission enhancement in the ERCOT Delaware Basin Load Integration

[2] https://www.ercot.com/files/docs/2020/11/27/27706_ERCOT_Letter_to_Commissioners_-_Follow-up_Status_Update_on_Permian....pdf

[3] https://www.ercot.com/files/docs/2023/03/17/Presentation%20to%20ERCOT%20planning.pdf

Study[4]. The 2023 RTP identified the need for this project beginning in the 2026 minimum load case to resolve observed reliability violations.

- Midland East to Falcon Seaboard to Morgan Creek to Tonkawa Switch 345-kV existing circuit rebuild in Midland, Howard, Mitchell, and Scurry Counties. This project was also identified as an ERCOT-preferred project in the Permian Basin Load Interconnection Study.[5]
- Morgan Creek to Longshore to Consavvy to Midessa South 345-kV double circuit line upgrade in Mitchell, Howard, and Midland Counties. This project was also identified as an ERCOT-preferred project in the Permian Basin Load Interconnection Study.[6]
- Cedarvale 345/138-kV substation expansion and 345/138-kV transformer additions in Upton and Ward Counties. This project serves as a placeholder project to address the reliability needs in the area. The Tier 1 TNMP Silverleaf and Cowpen 345/138-kV Stations Project is intended to address similar reliability violations and was endorsed by the ERCOT Board of Directors in December 2023.
- Consavvy South 345/138-kV substation and 345/138-kV transformer additions and 345-kV line addition from Consavvy South to Consavvy in Midland County.
- Yellow House Canyon Substation 345/115-kV transformer upgrade in Lubbock County.
- Kiamichi substation 345-kV reactors addition in Pittsburg County.
- International Airport 345/138-kV substation expansion and 345/138-kV transformer addition and 345-kV line addition from International Airport to Liggett Switch in Dallas County.
- Carmichael Bend Switch to Benbrook Switch 345-kV line upgrade in Tarrant and Hood Counties.
- Watermill Switch to Loop Nine Switch 345-kV line upgrade in Dallas County.
- Gunter 345/138-kV substation addition in Cooke, Denton, Collin, and Grayson Counties.
- Killeen Switch to Salado Switch 345-kV line upgrade in Bell County.
- Renner Switch 345/138-kV transformer upgrade in Collin County.
- Tri Corner to Seagoville Switch to Forney Switch 345-kV line upgrade in Dallas County.
- Venus Switch to Fort Smith Switch to Sam Switch to Four Brothers Switch to Tradinghouse SES to Lake Creek SES 345-kV double-circuit line upgrade in Ellis, Hill, and McLennan Counties.

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4 https://www.ercot.com/files/docs/2019/12/23/ERCOT_Delaware_Basin_Load_Integration_Study_Public_Version.zip

5 https://www.ercot.com/files/docs/2021/12/08/ERCOT_Permian_Basin_Load_Interconnection_Study_Public.zip

6 *Id.*

- Venus Switch to Navarro to Outlaw Switch to Limestone Plant to Jewett 345-kV double-circuit line upgrade in Ellis, Navarro, Freestone, Limestone, and Leon Counties.
- Navarro to Big Brown SES 345-kV line upgrade and Big Brown to Jewett 345-kV double-circuit line upgrade in Navarro, Freestone, and Leon Counties.
- Michell Bend Switch to Padera Sub 345-kV line addition in Hood County.
- Temple Pecan Creek to Temple Switch 345-kV line upgrade in Bell County.
- Watermill Switch 345/138-kV transformer upgrade in Dallas County.
- Everman Switch 345/138-kV transformer addition in Tarrant County.
- Lake Creek SES 345/138-kV transformer upgrade in McLennan County.
- Temple Pecan Creek and Temple Switch 345/138-kV transformer additions in Bell County.
- Whitney 345/138-kV transformer upgrade in Hill County.
- North Rosenberg 345-kV substation addition and 345-kV line additions from Whaley to North Rosenberg and Obrien in Fort Bend County.
- South Texas Project to WA Parish 345-kV line upgrade in Matagorda, Wharton, and Fort Bend Counties.
- Beck Road 345/138-kV substation expansion and 345/138-kV transformer additions in Bexar County.
- Lytton Springs 345/138-kV transformer addition in Caldwell County.
- Austrop 345/138-kV transformer addition in Travis County.
- Lytton Springs to Garfield to Austrop 345-kV line upgrade in Caldwell, Bastrop, and Travis Counties.
- Cachena substation 345-kV Reactor Addition in Lavaca County.
- Dunlap 345/138-kV transformer addition in Travis County.
- South to central Texas 345-kV double-circuit line additions in San Patricio, Bee, Karnes, Wilson, Guadalupe, Comal, Hays, Travis, and Williamson Counties.
- Scooter 345/138-kV substation addition in Milam County.

The 2023 RTP also included an economic assessment of the ERCOT transmission system for years 2025 and 2028 using both the production cost savings test and the generator revenue reduction test. Through this assessment, ERCOT identified transmission congestion and tested various transmission improvements to address this congestion in a cost-effective manner (as defined by ERCOT's economic planning criteria). Twenty economic transmission improvement projects were evaluated in the 2023 RTP. The tested transmission solutions did not meet either of the economic planning criteria. Detailed economic analysis results can be found in section 4 of this report.

The estimated project completion years provided in the 2023 RTP report were chosen to address reliability needs in a timely manner. The TOs are expected to meet these project completion dates,but lead times necessary to implement projects based on factors, such as availability of construction clearances, the time required to receive regulatory or governmental approvals, equipment availability, land acquisition, and resource constraints, may result in different actual project completion dates.

The projects identified in the RTP do not represent ERCOT's endorsement of the projects. Instead, they represent suggested CAPs for the reliability criteria violations identified under the system conditions studied in the RTP. The scopes of projects identified in the RTP may change based on further analysis by ERCOT or the TPs that indicate better alternatives or a need to modify the projects due to changes in expected generation, load forecasts, or other system conditions. To confirm need, TPs should perform studies with the latest system conditions and develop applicable reliability projects to resolve any reliability criteria violations.

For projects that are subject to ERCOT Protocols Section 3.11.4, Regional Planning Group Project Review Process, a review shall be conducted in accordance with the process described therein. For a project that is under Regional Planning Group (RPG) review when the RTP is developed, a placeholder project will be used if the need is identified. Projects requiring RPG endorsement will be reviewed in future assessments (where sufficient lead-time exists), such as future RTPs, to ensure the identified system facilities are still needed.

The TOs will provide ERCOT with additional details on project scope, project cost, and an implementation schedule with completion date(s) for each identified project. This information from the TOs may be provided through further RPG review and/or Transmission Project Information Tracking (TPIT) updates in accordance with ERCOT Planning Guide Section 6.4.1.

Table of Contents

1. 2023 Regional Transmission Plan

This report documents the 2023 Regional Transmission Plan (RTP) assessment performed by ERCOT Grid Planning. It is intended, in part, to satisfy ERCOT's requirements under NERC Reliability Standards, ERCOT Protocols Section 3.11, and ERCOT Planning Guide Sections 3 and 4.

The RTP study is conducted annually for the entire ERCOT System. The 2023 RTP's near-term and long-term planning horizon analysis evaluated the reliability needs of the ERCOT transmission system for the years 2025 through 2029. As required by NERC Reliability Standard TPL-001-5.1, the 2023 RTP included a steady-state analysis of summer peak conditions for years 2025 (year 2), 2026 (year 3), and 2028 (year 5); and off-peak conditions for 2026 (year 3); and a short-circuit analysis of summer peak conditions for 2026 (year 3). The 2023 RTP also included steady-state analysis of summer peak conditions for 2029 (year 6), representing the long-term planning horizon. Year six, *i.e.* 2029, was selected based on the rationale that most transmission upgrades in the ERCOT region can be completed within five to six years from the date when the need is identified. In addition to analyzing the reliability needs of the system, the 2023 RTP also evaluated economic/efficiency needs of the ERCOT system for years 2025 and 2028.

1.1. Stakeholder Involvement

The development of the RTP is a collaborative process. ERCOT worked with NERC-registered TPs, TOs, and other stakeholders to develop the input assumptions and the scope of technical studies that define the 2023 RTP. These assumptions are described in the RTP Scope and Process document and were presented to the stakeholder community at Regional Planning Group (RPG) meetings. The RTP Scope and Process document and input assumptions can be found in Appendices A, B, C, and D. Stakeholders were provided with routine updates on the input assumptions and supporting analysis performed for the 2023 RTP in RPG meetings. Feedback and comments from the RPG were incorporated into the RTP Scope and Process document.

The RPG is responsible for reviewing and providing comments on proposed transmission projects in the ERCOT Region. Under ERCOT Protocols Section 3.11.3, participation in the RPG is required of all Transmission Service Providers and is open to all Market Participants, consumers, other stakeholders, and Public Utility Commission of Texas (PUCT) staff.

ERCOT worked with TPs, TOs, and other stakeholders to study the existing system and to identify system upgrades and new transmission projects to ensure continued system reliability.

1.2. Standards and Regulations

The RTP assessment was conducted based on requirements in NERC Reliability Standards, ERCOT Protocols, and the ERCOT Planning Guide.

ERCOT performed its steady-state reliability assessment in accordance with NERC Reliability Standard TPL-001-5.1, Transmission System Planning Performance Requirements. A portion of the RTP assessment also addressed some requirements in NERC Reliability Standards FAC-002[7] and IRO-017.[8]

ERCOT Protocols Section 3.10.8.4(3) requires ERCOT to identify additional Transmission Elements that have a high probability of providing significant added economic efficiency to the ERCOT market through the use of Dynamic Ratings and request such Dynamic Ratings from the associated ERCOT Transmission Service Provider (TSP). This report identifies such Transmission Elements as part of its economic analysis.

The RTP assessment adheres to ERCOT Planning Guide Section 3.1.1.2, which provides guidelines regarding completion of the RTP. This section requires that ERCOT complete and publish the final RTP report no later than December 31 each year. Additionally, ERCOT Planning Guide Section 4 and ERCOT Protocols Section 3.11.2 specify the transmission planning criteria to be used in the RTP assessment.

1.3. Confidentiality and Report Posting

The RTP report is shared with internal and external stakeholders. One redacted version of the RTP is created by removing, at a minimum, any confidential data such as the list of long lead-time equipment. This report is shared with ERCOT stakeholders via the MIS Secure area. A public version of the RTP report is also created by removing, at a minimum, any confidential data and ERCOT Critical Energy Infrastructure Information (ECEII). This report is posted to the ERCOT website.

[7] FAC-002, Requirement R4
[8] IRO-017, Requirements R3 and R4

2. 2023 Regional Transmission Plan Process

The RTP study process is described in Figure 1. The initial start cases to be used in the reliability analysis were prepared in the case conditioning stage. The case conditioning stage for the 2023 RTP also included the use of the “bounded-higher-of” methodology to determine appropriate Weather Zone load levels for the RTP study. The details of this methodology can be found in ERCOT Planning Guide Section 3.1.7, Steady State Transmission Planning Load Forecast. In the 2023 RTP, the Permian Basin load forecast from the IHS Markit study was utilized for the West and Far West Weather Zones with some adjustment based on input from TSPs serving the region. Following case conditioning, a reliability analysis was conducted on the base case to determine the CAPs needed to meet ERCOT and NERC reliability requirements. In addition to the base case, the 2023 RTP also included sensitivity cases, a short-circuit analysis, a cascade analysis, a known outages study, and a multiple element outage analysis as required by NERC Reliability Standard TPL-001-5.1. A minimum deliverability analysis was performed based on the criteria defined in ERCOT Planning Guide Section 4.1.1.7, Minimum Deliverability Criteria, and the threshold approved by the ERCOT Board of Directors.[9] Economic analysis was also conducted to identify transmission projects that allow reliability criteria to be met at a lower total cost. The detailed scope, process, and input assumptions used in conducting reliability and economic analyses are available in Appendices A, B, and D.

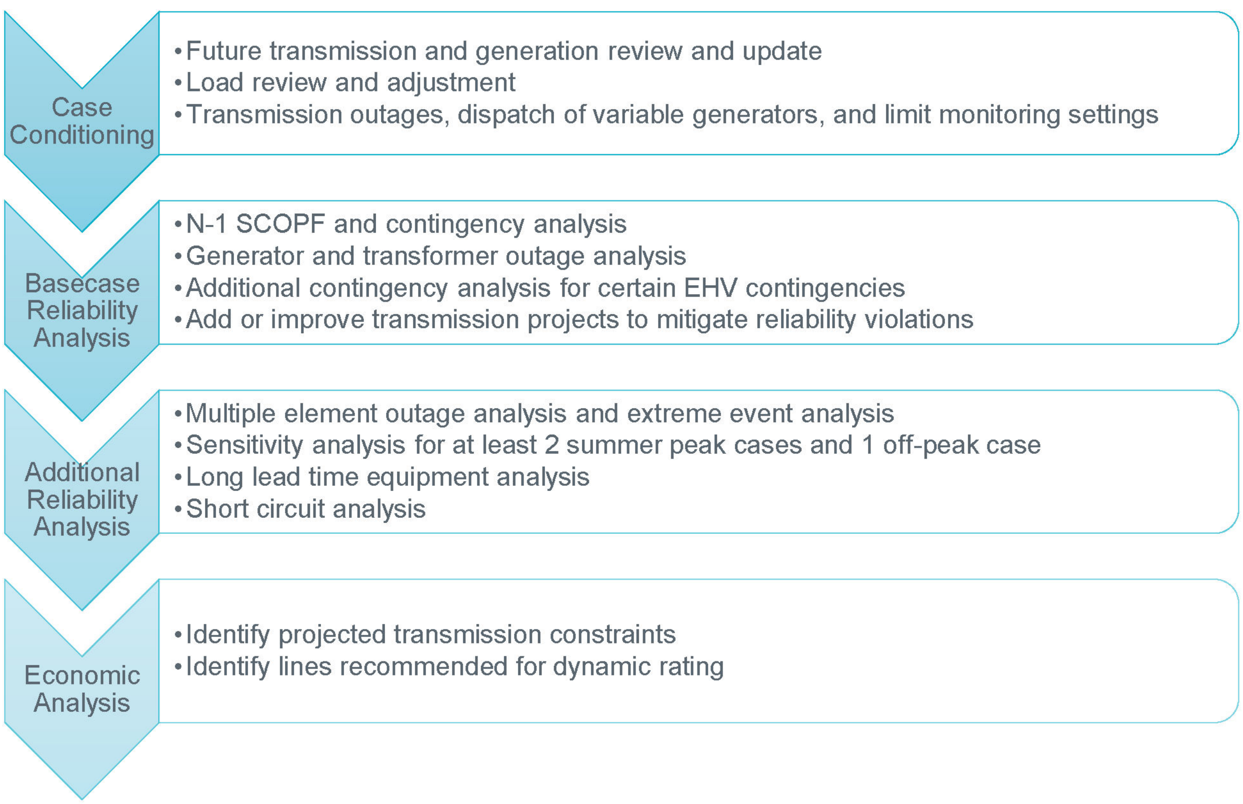

Figure 1: 2023 RTP Transmission Planning Process

[9] https://www.ercot.com/files/docs/2022/06/28/Minimum_Deliverability_Criteria_Thresholds.pdf

ERCOT utilized the following software tools while performing the 2023 RTP:

- PSS/E version 35 was used to develop the conditioned cases.
- PowerWorld version 23 with Security Constrained Optimal Power Flow (SCOPF) and its SIMAUTO functionality were used to perform AC SCOPF analysis and to run generator and transformer outage analysis.
- PowerWorld version 23 was used to screen critical contingencies while evaluating P3 (generator outage) and P6-2 (transformer outage) planning events.
- PowerWorld version 23 was used to perform multiple element outage analysis and cascading analysis.
- UPLAN version 11.4 was used to perform security-constrained economic analysis.

2.1. Permian Basin Load Forecast and Large Load Additions

In order to better prepare for the challenges in transmission planning introduced by the rapid load growth in the Permian Basin, coupled with the short lead time of oil and gas load interconnection requests, ERCOT and TSPs serving West Texas oil and gas load have been working proactively to better understand oil and gas activities and growth and to position the Texas grid for potential long lead time transmission enhancements needed to reliably serve the fast-growing loads.

ERCOT completed the Delaware Basin Load Integration Study with extensive input from TSPs in 2019 and identified a five-stage transmission upgrade road map to reliably serve different levels of Delaware Basin load. In addition, both ERCOT and TSPs have also evaluated West Texas oil and gas load growth at a more granular level. In April 2020, a TSP-sponsored IHS Markit study report for Permian Basin load forecast was published, which was based on an in-depth analysis of the oil and gas activities in the Permian Basin and provided the load forecast with more granularity. The Permian Basin load forecasted in the IHS Markit study was reviewed by ERCOT and TSPs serving the load within the Permian Basin area and was determined to be appropriate for use in the RTP analysis. ERCOT also engaged with the Tight Oil Resource Assessment (TORA) program of the Bureau of Economic Geology (BEG) at University of Texas at Austin for the West Texas Load Study in 2022. The study showed consistent load forecast compared with the IHS Markit study. Since the completion of the IHS Markit demand forecast in the first quarter of 2020, there have been a significant number of customer-specific requests for new electric service in the Permian Basin region, including in and around the Stanton Loop area. The requests in this area include new operations as well as electrification of existing “off-grid” operations. ERCOT used the 2022 S&P Global Commodity Insights (formerly IHS Markit) Permian Basin load forecast as a reference to verify the additional Stanton Loop area load incorporated (around 1,300 MW for year 2029) in the 2023 RTP on top of the 2019 IHS Markit load forecast.

The Permian Basin load forecast from the IHS Markit study included all but four counties in the Far West Weather Zone and five adjacent counties in the West Weather Zone. The counties and load forecast from 2022 to 2030 associated with the Permian Basin area can be found in Table 1 and Figure 2, respectively.

Table 1: Permian Basin Counties

County	Weather Zone
Andrews	Far West
Borden	Far West
Crane	Far West
Crockett	Far West
Culberson	Far West
Dawson	Far West
Ector	Far West
Glasscock	Far West
Howard	Far West
Irion	West
Loving	Far West
Martin	Far West
Midland	Far West
Mitchell	West
Pecos	Far West
Reagan	Far West
Reeves	Far West
Schleicher	West
Scurry	West
Sterling	West
Upton	Far West
Ward	Far West
Winkler	Far West

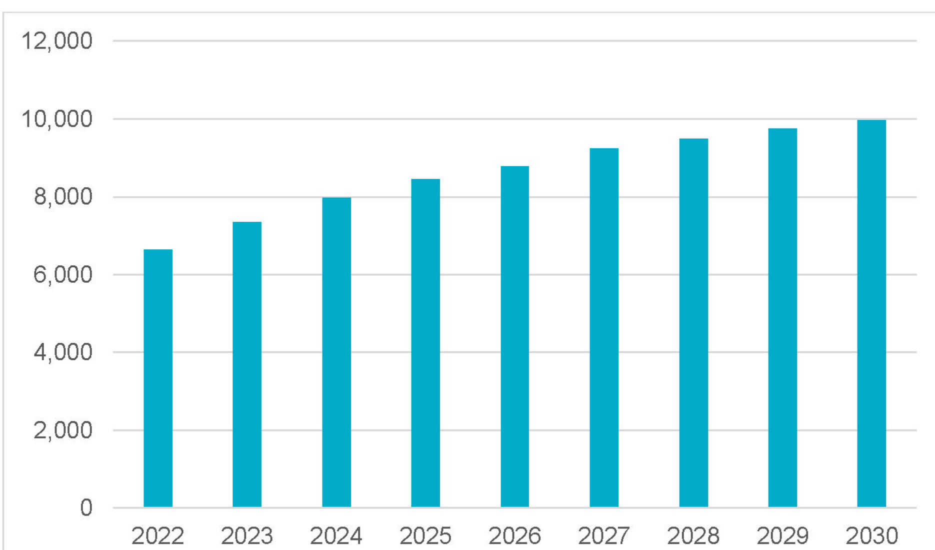

Figure 2: IHS Markit Study Permian Basin Summer Peak Load Forecast (MW)

While a large portion of the Permian Basin loads can be served from existing or planned substations, there are also projected new loads that would require new interconnections to the existing transmission system. Similar to the 2021 and 2022 RTP, the new load interconnection was assumed to be consistent with the ERCOT Permian Basin Load Interconnection Study in the 2023 RTP. The new load-serving stations and their connections to the existing transmission system can be found in Appendix C.

Similar to the 2022 RTP, the increase of the large load interconnection requests continued in 2023. ERCOT worked with TSPs and considered signed contracts for the large loads to determine the appropriate load to be included in the analysis. Figure 3 below shows the amounts of the large load included in each study year. The large loads include cryptocurrency load, data center load, and manufacturing load.

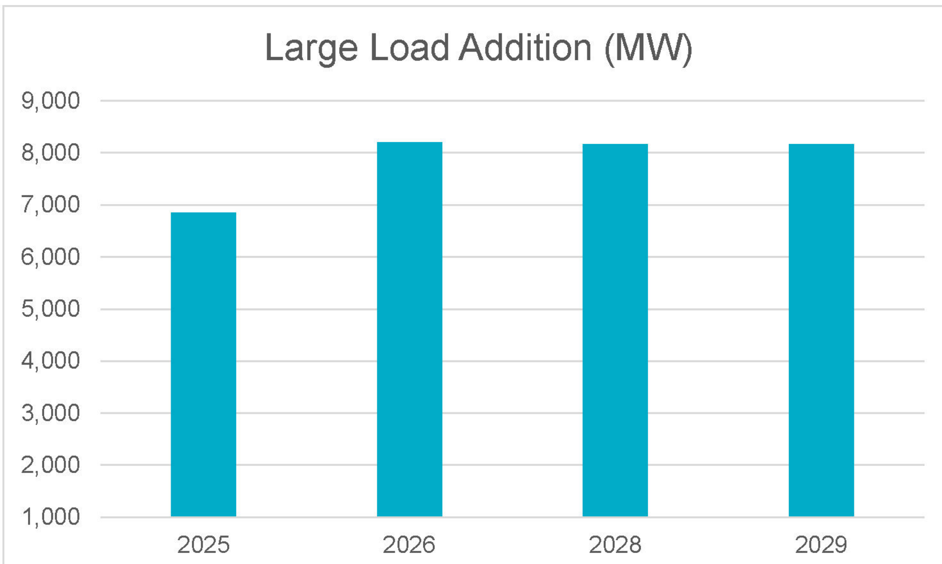

Figure 3: Large Load Addition in 2023 RTP (MW)

2.2. Adoption of the ERCOT Rooftop Solar Growth Forecast

The rapid growth in Distributed Generation (DG), especially in the solar photovoltaic less than 1 MW category, continued in the ERCOT region. The total DG at the end of 2022 is estimated to be more than 3,850 MW, as shown in Figure 4.

Similar to the 2022 RTP, the impacts of the projected rooftop solar growth were incorporated as load reductions at the bus level in the 2023 RTP.

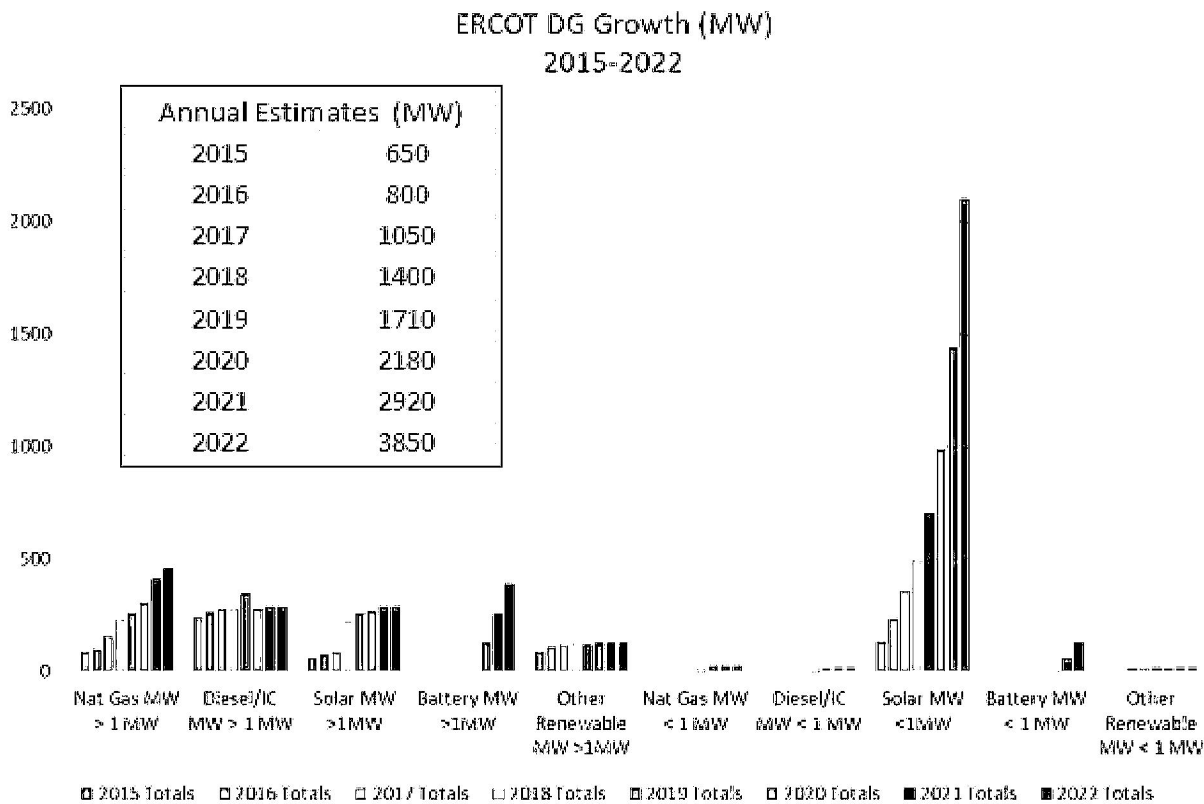

Figure 4: ERCOT Estimated Total DG Growth from 2015 to 2022 (MW)

2.3. Adoption of the Electrical Vehicle (EV) Load Impact Forecast

Adoption of EVs is expected to increase significantly in the near future with 4% of all the vehicles on the road projected to be EV in Texas by 2029 and 6.7 TWh of load from EV charging by that same year. This signifies a need to include EV load impacts in near-term planning studies.

ERCOT engaged with TDSPs on the discussion of EV adoption in 2021 and retained the Brattle Group in 2022 to develop a methodology and process[10] to produce EV charging load forecasts at the substation level. The substation-level EV load impacts generated as an outcome of this project are incorporated into the 2023 RTP.

[10] https://www.ercot.com/files/docs/2023/08/28/ERCOT-EV-Adoption-Final-Report.pdf

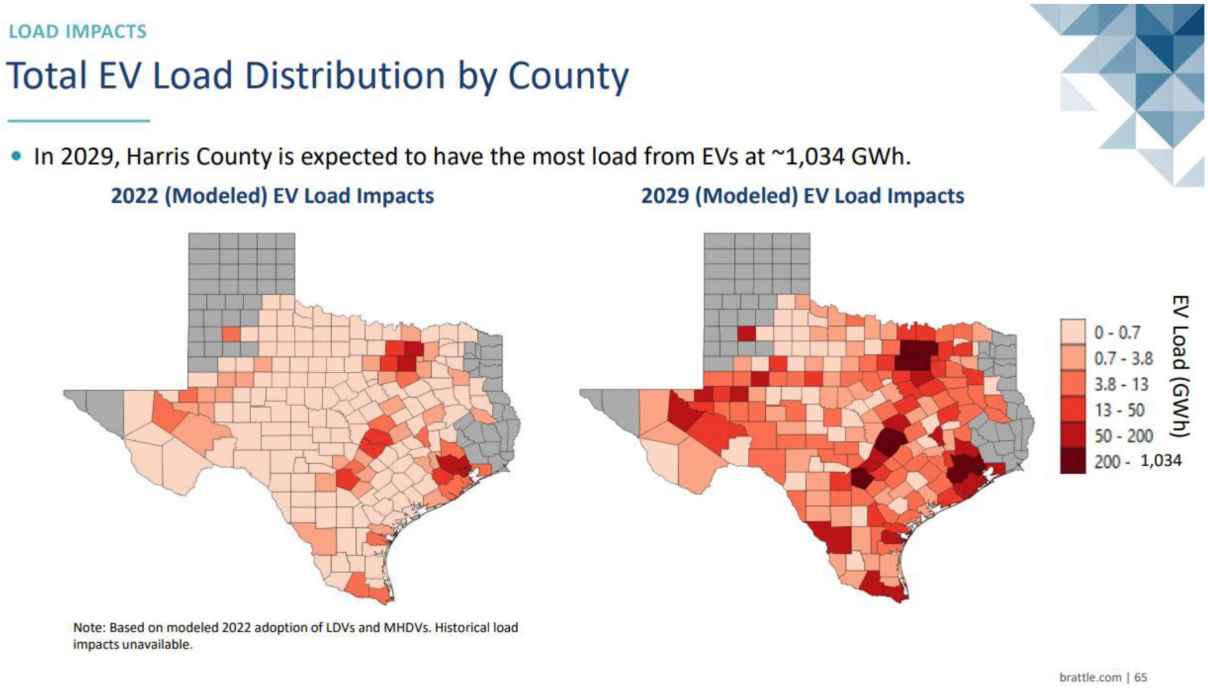

Figure 5: ERCOT Estimated EV Load Distribution by County[11]

2.4. Reliability Analysis

The reliability analysis in the 2023 RTP was focused on the steady-state analysis requirements of NERC Reliability Standard TPL-001-5.1 and the ERCOT Planning Guide. The purpose of reliability analysis was to identify potential criteria violations and CAPs that may be used to resolve them. The RTP analysis included Security Constrained Optimal Power Flow (SCOPF) to identify unresolvable constraints. Loading and voltage levels at Bulk Electric System (BES) elements were monitored for all NERC planning events, including extreme events. ERCOT staff developed CAPs in collaboration with TPs to mitigate criteria violations in accordance with the NERC and ERCOT performance requirements.

The 2023 RTP reliability analysis included the following studies:

- SCOPF: Security Constrained Optimal Power Flow (SCOPF) was used to perform basic power flow and Contingency Analysis for P0, P1, P2-1, and P7 planning events. SCOPF used generation cost data and other system constraints to give an optimal generation dispatch and unit commitment while maintaining the reliability of the system. In this analysis, the software simulated the removal of all elements of the Protection System and other automatic controls following the contingency event.
- Contingency Analysis: Basic contingency analysis routines in the power flow software were used to test P2-2, P2-3, P2-4, P4, and P5 planning events and extreme events.

[11] Ibid.

- Multiple Element Contingency Analysis: Planning events P3 and P6 involve a first- and second-level contingency analysis. Such events were tested using multiple element contingency analysis. During this analysis, loss of elements due to the first contingency was followed by acceptable system adjustments before testing the effect of the second contingency event. The list of acceptable system adjustments included system reconfiguration, changes in voltage schedule, and re-dispatch of generation. Other contingency events such as P4 and P5 planning events and extreme events, which involved simultaneous removal of multiple elements, were also analyzed. Extreme events associated with the disruption of gas pipelines were also included.
- Cascading Analysis: Cascading analysis was conducted to test all planning and extreme events where a facility may be loaded above its relay loadability rating before mitigation measures can be taken. In this analysis, the software simulated the removal of all elements of Protection System and other automatic controls following the contingency event. This included tripping of generators and transmission elements which were loaded beyond their relay loadability limits. These contingencies were screened to detect potential cascade events for more detailed analysis.
- Short Circuit Analysis: In accordance with the agreement between ERCOT and TPs in the ERCOT region as required by NERC Reliability Standard TPL-001-5.1, Requirement R7 (revised in May 2020), ERCOT performed the short-circuit analysis to determine short-circuit currents for Resource Entity (RE)-owned facilities. The results of the short-circuit analysis included the magnitude of short-circuit current and the source impedance associated with each fault. These results were communicated to the NERC-registered Generator Owners (GOs). GOs completed a review of study results, acknowledged the findings, and provided a list of over-dutied circuit breakers and CAPs. In addition, GOs also confirmed the continued validity and implementation status of the facilities identified in the previous RTP.
- Long Lead Time Equipment Analysis: Under Requirement 2.1.5 of NERC Reliability Standard TPL-001-5.1, the impact of the possible unavailability of major transmission equipment with a lead time of one year or more was studied. The studies were performed with an initial condition of the identified long lead time equipment modeled as out of service, followed by P0, P1, and P2 contingency events. The list of long lead time equipment was developed based on feedback from the TOs. The results of this analysis were communicated to the TOs.
- Sensitivity Analysis: ERCOT selected the summer peak conditions of 2025 and 2028 and off-peak conditions of 2026 for sensitivity analyses as required by Requirement 2.1.3 of NERC Reliability Standard TPL-001-5.1. ERCOT prepared the following sensitivity cases by varying the generation and load input assumptions:

    - Low solar net peak load conditions for years 2025 and 2028: Identify potential transmission upgrades needed, which may have different challenges compared with summer peak load conditions with high solar availability.

- High Renewable Light Load condition for the 2026 off-peak case: Identify potential challenges associated with high renewable dispatch. In this sensitivity, no renewable curtailment was utilized and potential solutions to accommodate the assumed level of penetration were identified.

The sensitivity analyses were performed with all identified reliability solutions from the base case analysis to evaluate the effectiveness and robustness of the base case solutions under the stressed system conditions.

- Known Outages Impact Analysis: Under Requirement 2.1.4 of NERC Reliability Standard TPL-001-5.1, the impact of known outages of generation or transmission facilities planned in the near-term planning horizon was studied. ERCOT issued Market Notices to collect known outages information from both TOs and GOs. TOs were required to provide technical rationales for their known outages selection for each study case included in the 2023 RTP. ERCOT developed the technical rationale[12] for the selection of GO-submitted outages to be included in the corresponding study cases. The known outages from the TOs and the GO outages selected based on ERCOT-developed technical rationale were then used to study their impact on system performance under P0 and P1 contingencies.
- Minimum Deliverability Analysis: As required by ERCOT Planning Guide Section 4.1.1.7, Minimum Deliverability Criteria, ERCOT performed analysis to ensure the deliverability of 100% of capacity of Generation Resources, utilizing combined cycle, steam turbine, combustion turbine, hydro, or reciprocating engine technology, and for any Energy Storage Resource (ESR) with a duration greater than or equal to 2 hours. For ESRs with a duration less than 2 hours, a prorated deliverability was ensured. CAPs were proposed to address any reliability violations under the contingencies defined for the minimum deliverability criteria.

2.4.1 CAP Development

Under the ERCOT Planning Guide, reliability projects are those system improvements (projects) that are needed to meet NERC Reliability Standards or ERCOT planning criteria, which could not otherwise be met by simultaneously feasible, security-constrained re-dispatch of existing and planned generation. To develop this list of projects, grid simulation software was utilized which included the removal of all protection system elements and other automatic controls following the simulated contingency events. These elements included devices designed to provide steady-state control of electrical system quantities, such as on-load tap-changing transformers, phase-shifting transformers, and switched capacitors and reactors.

A list of potential CAPs, or reliability projects, along with the corresponding limiting elements and contingencies, was communicated to the appropriate TP and/or TO. TPs and TOs reviewed the initial list of reliability-driven projects for their technical feasibility and estimated year of completion (considering necessary lead times). In some cases, the TOs also provided project alternatives. In instances where it is not feasible to construct a project prior to the identified date of need, ERCOT

[12] https://www.ercot.com/files/docs/2022/03/09/2022_RTP_TPL_001-5_Known_Outages_March_2022_RPG.pdf

designed Constraint Management Plans (CMP) to mitigate the criteria violations until the permanent CAP can be put in-service. These mitigation actions were developed in collaboration with TPs and further communicated to ERCOT Operations. The results were posted on the ERCOT MIS Secure Area. Study findings were presented to stakeholders at regularly scheduled RPG meetings to solicit comments and suggestions.

2.4.2 System Operating Limit (SOL) Identification

The ERCOT SOL Methodology was used to determine if additional SOLs were needed in the planning horizon. Per the criteria, a new SOL was identified if results of the reliability analysis of the base case resulted in any of the following:

- Voltage instability (resulting in uncontrolled voltage collapse)
- Cascading or uncontrolled separation or islanding

2.5. Economic Analysis

ERCOT conducted an economic analysis to identify system improvements that allow ERCOT to meet NERC Reliability Standards and ERCOT planning criteria more economically than the continued dispatch of higher cost generation.

To identify such economically driven projects, ERCOT created a production cost model for years 2025 and 2028. Details on the production cost models developed for the 2023 RTP can be found in Appendices D and E.

According to the economic planning criteria described in ERCOT Nodal Protocols Section 3.11.2(5), ERCOT recommends an economic project if the annual production cost savings exceed the first-year annual revenue requirement for the project. Based on the recent review of current market conditions, the first-year annual revenue requirement for a project was determined to be 13.2% of the estimated project cost.

In addition, ERCOT also recommends an economic project if the annual Generator Revenue Reduction (GRR) exceeds the average of the first three-year annual revenue requirement for the project, as allowed by the PUCT Substantive Rule § 25.101, while ERCOT is working on the development of the congestion cost savings test in consultation with PUC staff. Based on the recent review of current market conditions, the average of the first three-year annual revenue requirement for a project was 12.9% of the estimated project cost.

3. Findings from Reliability Analysis

3.1. Reliability Projects and Constraint Management Plans

The primary purpose of the 2023 RTP reliability analysis was to identify reliability criteria violations and potential CAPs to resolve them. Overall, the base reliability analysis identified a need for 173 CAPs. The detailed list of criteria violations and resulting CAPs can be found in Appendix F. Figure 6 illustrates the geographic location of the identified CAPs. The legend linking reliability projects and their associated map indices can be found in Appendix G.

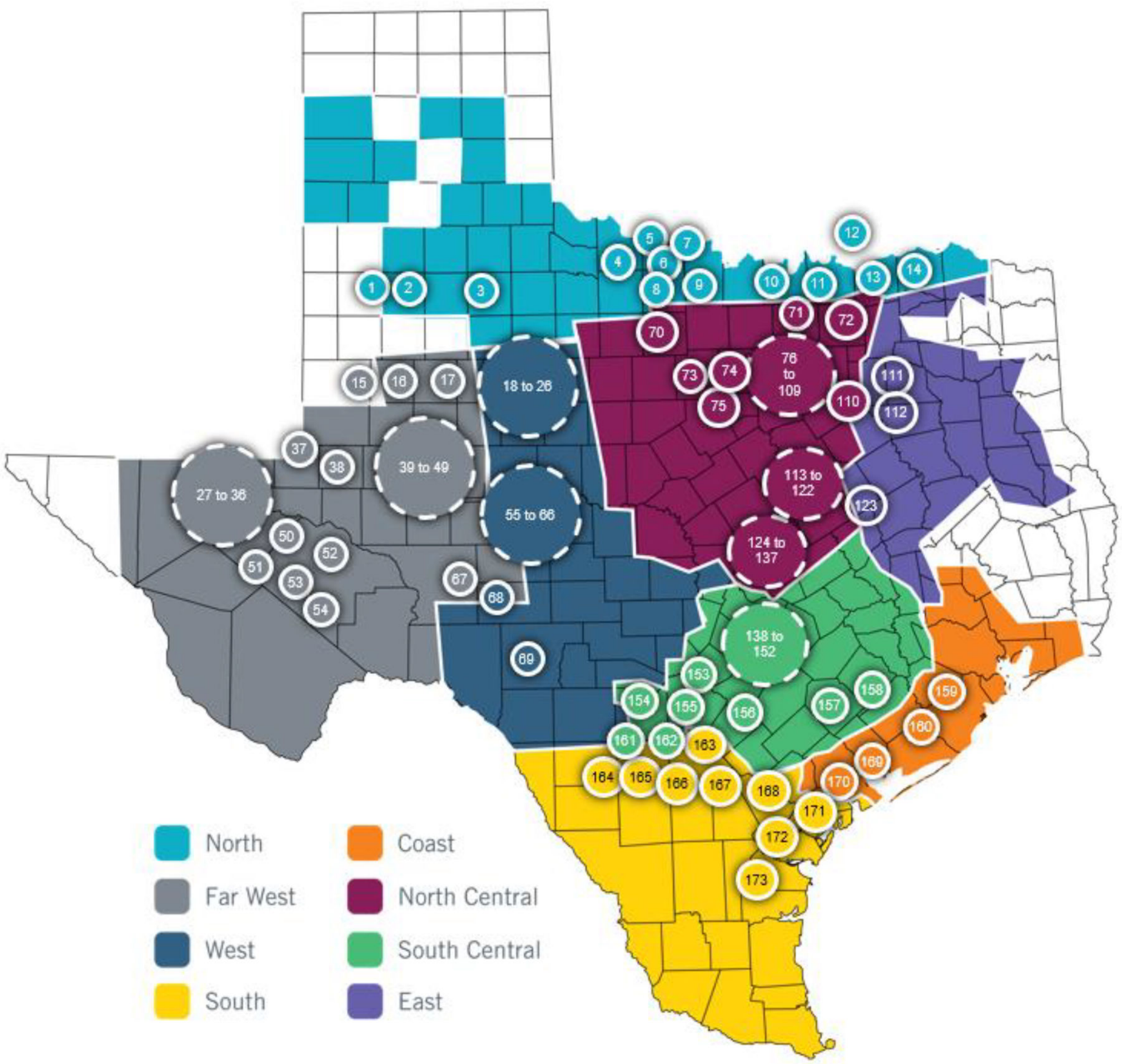

Figure 6: Geographic Locations of CAPs Identified in the 2023 RTP

Figures 7[13] and 8 summarize the types of projects, their geographic locations, and associated voltage levels. Figure 9 distinguishes between projects that were newly identified in the 2023 RTP and projects that were identified in previous ERCOT planning studies or TSP studies.

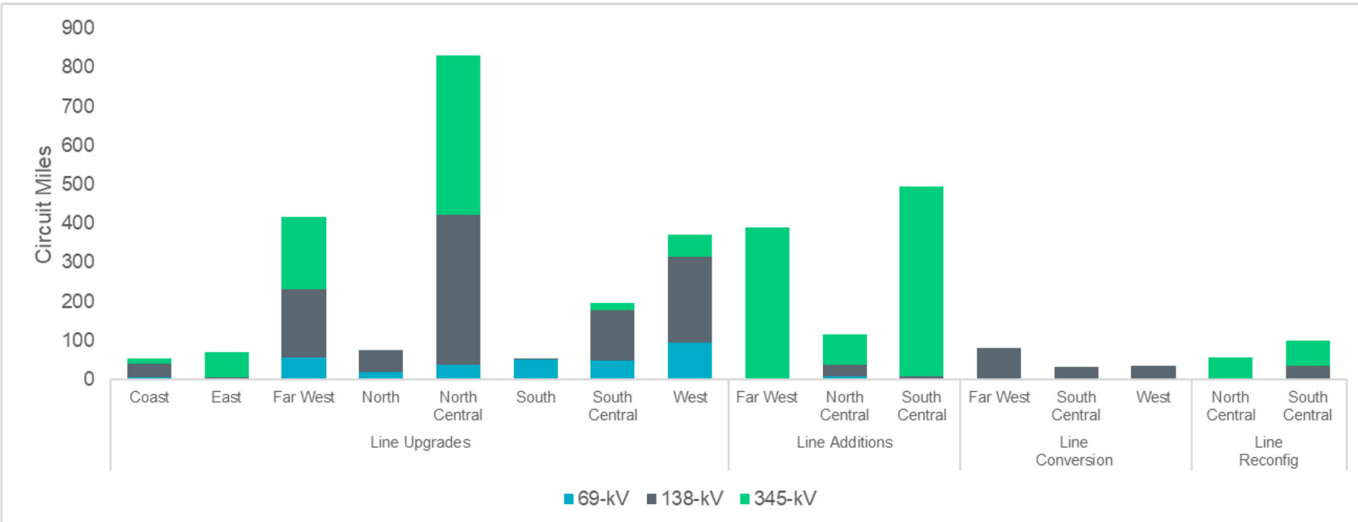

Figure 7: 2023 RTP Transmission Line Project Types by Weather Zone and Voltage Level

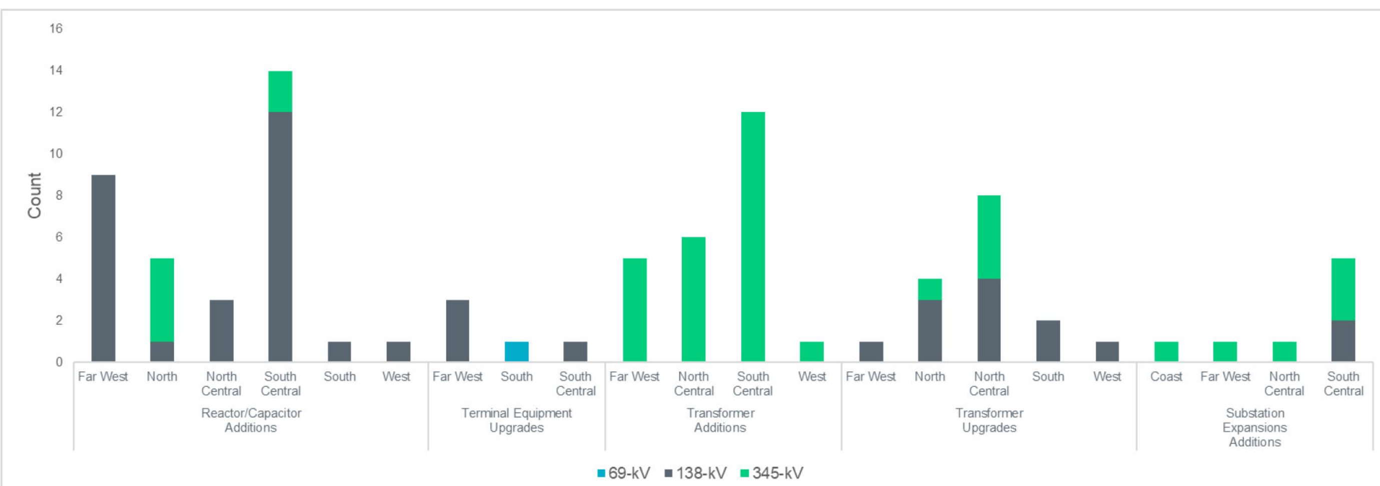

Figure 8: 2023 RTP Other Upgrades and Additions by Weather Zone and Voltage Level

[13] The 69-kV to 138-kV line conversion was included in the 138-kV category.

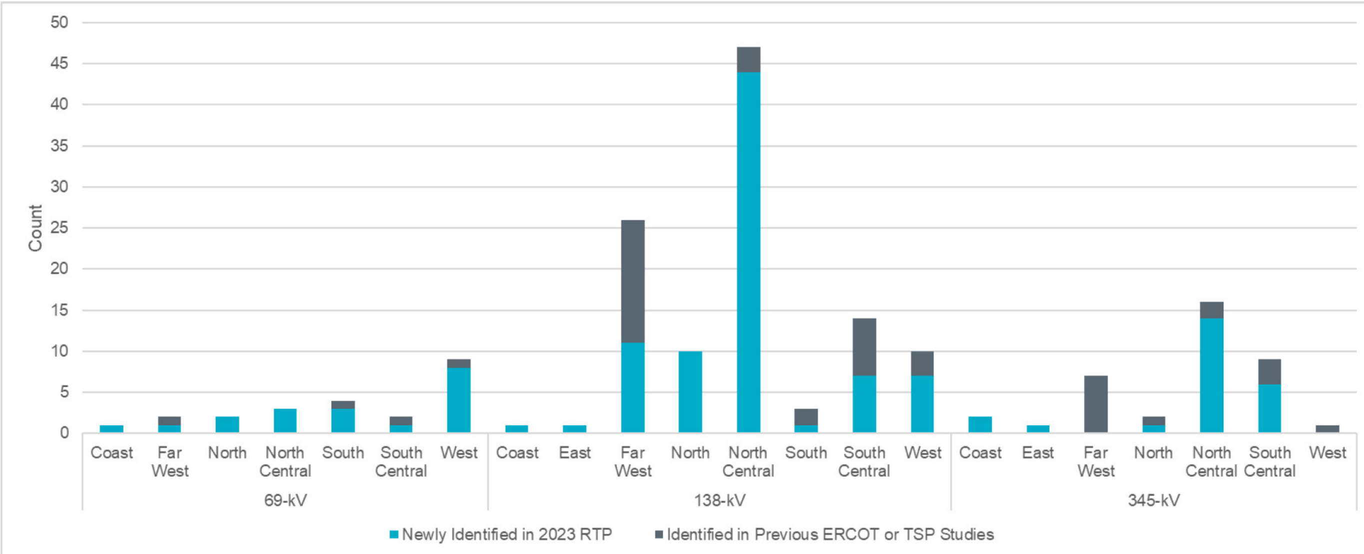

Figure 9: Projects Newly Identified in the 2023 RTP versus Projects Previously Identified

ERCOT, in collaboration with TPs, also identified two potential CMPs as placeholder mitigating actions, which will be reviewed in the operations planning horizon by ERCOT and TOs. The list and details of the CMPs identified in the 2023 RTP can be found in Appendix H.

3.1.1 West Texas Study Findings

As described in Section 2.1, the Permian Basin load forecast from the IHS Markit study was adopted in the 2023 RTP, similar to the 2021 and 2022 RTPs. Besides the forecasted demand that can be served from the existing and planned substations, there are 120 projected new oil and gas loads served from new stations through new interconnections to the existing transmission grid by year 2029. In the 2023 RTP, those new load serving stations are mostly radially connected to the existing system, which is consistent with the ERCOT Permian Basin Load Interconnection Study. The new load connection information can be found in Appendix C. The focus of the 2023 RTP was on the system impacts from loads served from both existing and planned substations and the new substations with assumed connections.

Compared with the 2021 and 2022 RTP, additional oil and gas load reflecting the expected increase in electrification, which was not reflected in the 2019 IHS Markit study load forecast, was added. This added around 1.3 GW of additional oil and gas load for study year 2029.

Similar to the 2022 RTP, a significant amount of large load in the Far West Weather Zone based on ERCOT load review results, was also incorporated, which brings the total projected load to around 14.6 GW under summer peak conditions by 2028 in the Far West Weather Zone. For the same study year, the load forecast used for the Far West Weather Zone was around 12 GW in the 2022 RTP.

With more than 50% of the 14.6 GW load located in the Delaware Basin area, various reliability violations were observed under the loss of part of the existing import paths into the Delaware Basin area and indicated the need for additional import paths into the area and the upgrade of the existing path.

The 2023 RTP identified the need for the stage 5 project (Faraday - Lamesa - Clearfork - Riverton 345-kV double circuit line addition) identified in the Delaware Basin Load Integration study road map to address the import needs in the area. The forecasted load level for the Delaware Basin area also exceeded the trigger point of 5,422 MW for the stage 5 project. The road map developed by the ERCOT Delaware Basin Load Integration study is shown in Figure 10. The need for the stage 5 project was also identified in the 2022 RTP.

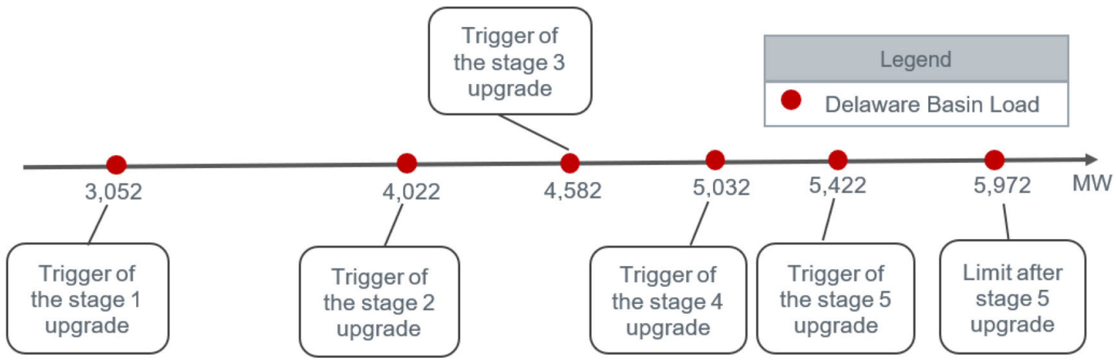

Figure 10: ERCOT Delaware Basin Load Integration Study Road Map

The 2023 RTP also identified the need for the majority of the preferred projects identified in the ERCOT Permian Basin Load Interconnection study. In addition, significant needs for the 138-kV and 69-kV transmission enhancements were also observed.

Overall, 55 reliability projects were identified for the West and Far West study region. The noteworthy reliability projects are summarized below. The detailed information can be found in Appendix F.

- Faraday to Lamesa to Clearfork to Riverton 345-kV double-circuit line addition in Borden, Dawson, Andrews, Winkler, Loving, and Reeves Counties. This project was also identified as the Stage 5 transmission enhancement in the ERCOT Delaware Basin Load Integration Study. The 2023 RTP identified the need for this project starting in the 2026 minimum load case to resolve observed reliability violations.
- Midland East to Falcon Seaboard to Morgan Creek to Tonkawa Switch 345-kV existing circuit rebuild in Midland, Howard, Mitchell, and Scurry Counties. This project was also identified as an ERCOT-preferred project in the Permian Basin Load Interconnection Study.
- Morgan Creek to Longshore to Consavvy to Midessa South 345-kV double circuit line upgrade in Mitchell, Howard, and Midland Counties. This project was also identified as an ERCOT-preferred project in the Permian Basin Load Interconnection Study.
- Cedarvale 345/138-kV substation expansion and 345/138-kV transformer additions and 345-kV double circuit line addition from Cedarvale to Sand Lake in Upton and Ward Counties. This project serves as a placeholder project to address the reliability needs in the area. The Tier 1 TNMP Silverleaf and Cowpen 345/138-kV Stations Project is intended to address the same reliability violations and was endorsed by the ERCOT Board of Directors in December 2023.

- Consavvy South 345/138-kV substation and 345/138-kV transformer additions and 345-kV line addition from Consavvy South to Consavvy in Midland County.

3.1.2 Central Texas Study Findings

The retirement of conventional Generation Resources continued in 2023. The 2029 study case in the 2023 RTP has close to 1 GW of additional generation capacity offline in central Texas compared with the 2022 RTP based on the Resource Entities' notifications and public statements about their intention to retire those Generation Resources prior to the filing of a Notification of Suspension of Operations (NSO) in accordance with Planning Guide Section 3.1.4.1.1(4). The list of affected Generation Resources can be found in the "Generation Resources Unavailable in Planning Studies Prior to NSO" document[14] posted on the ERCOT website.

In December 2021, the "Howard Road 345/138 kV Switching Station Project" submitted by CPS Energy was accepted by RPG as a first step in addressing the reliability needs in the area introduced by the generation retirement in and around the San Antonio area. The "CPS San Antonio South Reliability Project", which added a double-circuit 345-kV line from Howard Road to San Miguel, was endorsed by ERCOT Board in 2023 to further address the reliability needs due to the increased retirements that were identified in both the 2021 and 2022 RTPs.

While retirements of conventional Generation Resources are accelerating, planned new Generation Resources are mostly wind, solar, and ESRs. This resource mix change results in the increased reliance on renewable resources to meet the increased demand and decreased flexibility in using renewable curtailment to resolve thermal violations. In the 2023 RTP, over 2,800 MW of new nameplate generation capacity in the South Weather Zone, compared to the 2022 RTP, is expected to be in service by summer of 2025. Of that additional capacity, approximately 2,300 MW are solar and wind. To serve the higher projected demand in central Texas, that new generation in the South Weather Zone is needed, and the RTP found an additional import path from South to Central Texas is needed to alleviate the stress on the existing 345-kV central Texas corridor. Coupled with that is a need for additional transformer capacity along the path to serve the load on the 138-kV network.

The concept of the additional import path need is illustrated in Figure 11.

[14] https://www.ercot.com/mp/data-products/data-product-details?id=PG3-1411-M

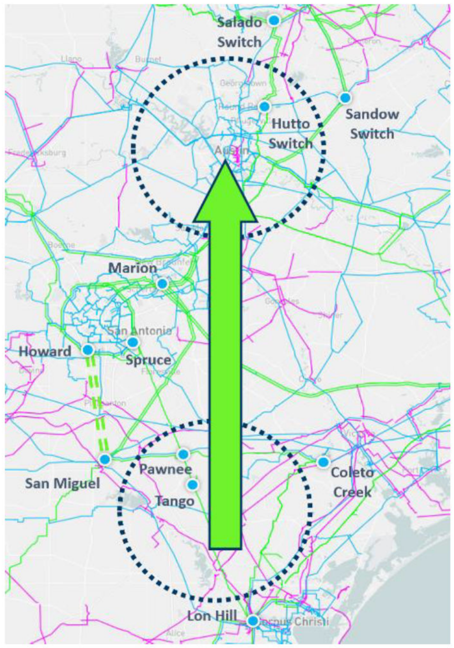

Figure 11: New South to Central Texas Import Path

The detailed description of the placeholder project adding the new path from South to Central Texas can be found in Appendix F. Expected future generation will likely impact these needs, and ERCOT and TSPs will continue to evaluate the need and additional project options.

3.1.3 Venus Switch Import Path

The resource mix change and the increased reliance on renewable Generation Resources to meet increased demand also introduced stress to the import path from Lake Creek/Jewett to Venus Switch towards the Dallas/Fort Worth (DFW) metroplex. Due to the increased reliance on renewables to serve demand, the flexibility of using renewable curtailment to resolve the violations decreased. By year 2029, approximately 350 miles of 345-kV upgrades are needed to accommodate the import flow into the Venus substation on its way to the DFW metroplex. The reliability needs of the Venus Switch import path is illustrated in Figure 12.

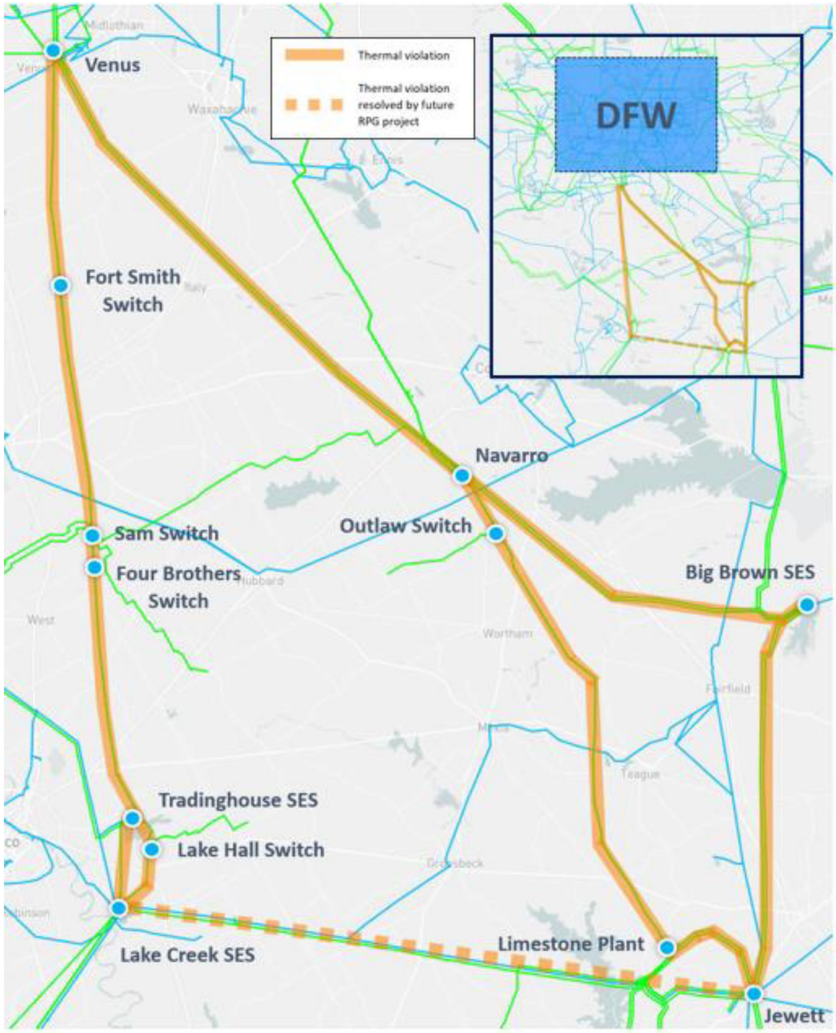

Figure 12: Venus Switch Import Path Reliability Needs

The detailed description of the placeholder projects to address the identified reliability needs can be found in Appendix F. Expected future generation will likely impact these needs, and ERCOT and TSPs will continue to evaluate the need and additional project options.

3.1.4 Southwest Houston Import Path

The 2023 RTP saw the addition of nearly 2,000 MW of new nameplate solar capacity southwest of Houston, compared to the 2022 RTP, expected to be in-service by summer of 2025. Approximately 1,000 MW of new solar is located west of the South Texas Project to WA Parish 345-kV line and 1,000 MW south of the South Texas Project station. Due to the increased reliance on renewables to serve demand, the flexibility of using renewable curtailment to resolve the transmission limit violations decreased and the 345-kV lines on the southwest Houston import path were overloaded more often. The reliability needs are illustrated in Figure 13.

The following placeholder projects were identified to address the identified reliability issues.

- North Rosenberg 345-kV substation addition and 345-kV line additions from Whaley to North Rosenberg to Obrien in Fort Bend County.
- South Texas Project to WA Parish 345-kV line upgrade in Matagorda, Wharton, and Fort Bend Counties.

The detailed description of the placeholder projects can be found in Appendix F. Expected future generation will likely impact these needs, and ERCOT and TSPs will continue to evaluate the need and additional project options.

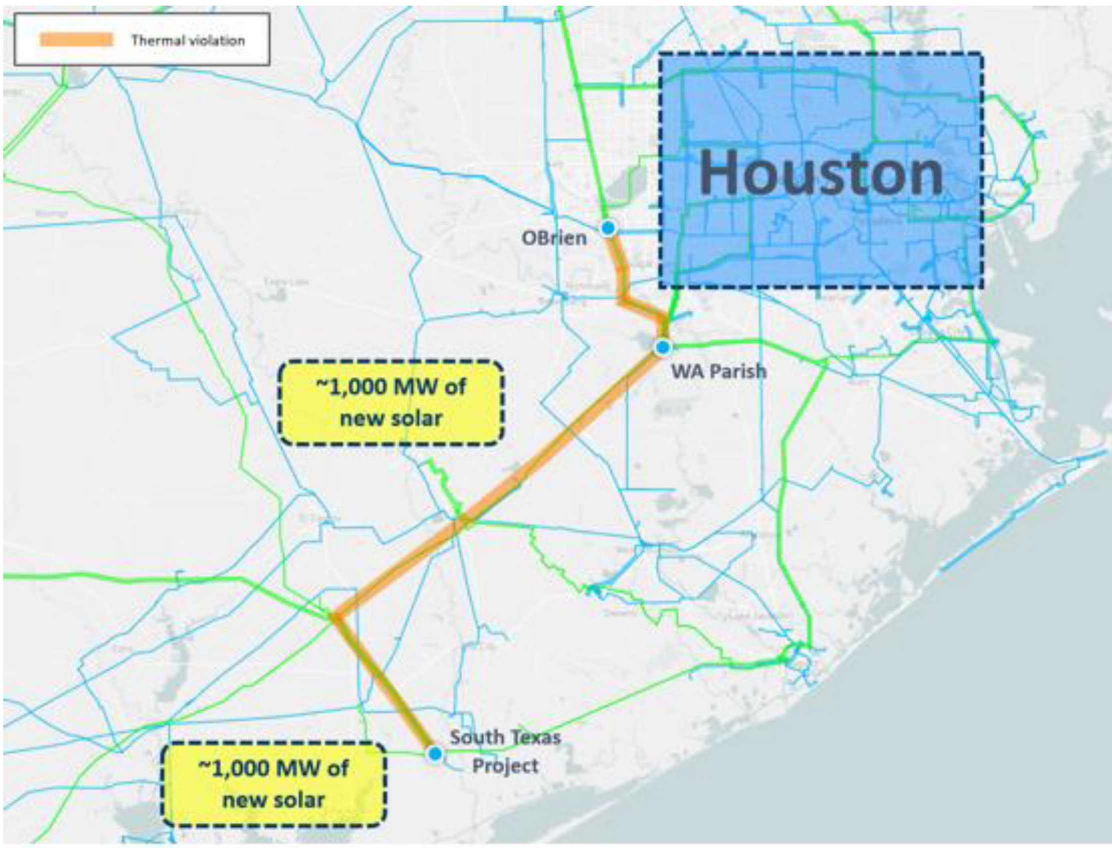

Figure 13: Southwest Houston Import Path Reliability Needs

3.1.5 Other Findings

In addition to the reliability analysis summarized in previous sections, a multiple element outage analysis was conducted for contingencies where non-consequential load loss is allowed under NERC Reliability Standard TPL-001-5.1, Table 1. This consisted of:

- corrective action analysis, which identified mitigation measures (such as transformer tap setting changes, switching actions, generator re-dispatch, and load shed) to resolve any overloads and over/under-voltage issues resulting from such contingencies and

- cascading analysis, which identified any contingencies that could result in potential cascade events.

Some planning events and extreme events were screened for detailed analysis, and further investigation performed by ERCOT indicated that none of those events resulted in cascading conditions. ERCOT also studied the loss of multiple generating stations due to the disruption of gas pipelines. The results of the multiple element outage analysis are documented in Appendix I. This appendix includes the list of critical contingencies identified as a result of this analysis and CAPs or recommendations necessary to mitigate the impact of these contingencies. No new SOLs were identified in the 2023 RTP reliability analysis.

ERCOT also performed an analysis of known outages of generation and transmission facilities planned in the near-term planning horizon per Requirement 2.1.4 of NERC Reliability Standard TPL-001-5.1. ERCOT issued Market Notices[15] to collect known outages information from both TOs and GOs. TOs were required to provide technical rationales for their known outages selection for each study case included in the 2023 RTP. ERCOT developed the technical rationale for the selection of GO-submitted outages to be included in the corresponding study cases. The known outages from the TOs and the GO outages selected based on the ERCOT-developed technical rationale were then incorporated into the base cases to study their impact on system performance under P0 and P1 contingencies. The study results concluded that no additional violations were caused by the known outages.

For the minimum deliverability analysis, ERCOT created a coincident 2028 summer peak case as the start case for the analysis. The analysis found that additional transmission upgrades were needed to ensure the deliverability of the defined Generation Resources. The transmission upgrades were in Cherokee, Ellis, Dallas, Lubbock, and Brewster Counties. The detailed information can be found in Appendix O.

In addition to the above analyses, per ERCOT Planning Guide Section 3.1.1.2(3), the 2023 RTP analysis also included a list of transmission facilities that were loaded above 95% of their applicable ratings under normal and contingency events (loss of single generating unit, transmission circuit, transformer, or common tower outage). This list is attached to the report as Appendix J.

3.2. Sensitivity Analysis

The ERCOT grid continued to evolve on both the generation side and the demand side. The rapid growth of wind, solar, and energy storage resources, coupled with increased coal and gas generator retirement, continues to change the resource mix in the ERCOT region. Besides the changes on the generation side, the demand side is also experiencing substantial development, e.g., the robust oil and gas activity in West Texas, the increased interest in cryptocurrency mining facility development, and the expected increase in Electrical Vehicles (EV) adoption. The rapid evolvement in generation and demand brought additional challenges to the Texas grid. To understand potential challenges brought by the evolving grid, ERCOT developed various sensitivity cases in past RTPs. ERCOT

[15] https://www.ercot.com/services/comm/mkt_notices/W-B042523-01
https://www.ercot.com/services/comm/mkt_notices/W-C042523-01

reviews operational challenges and stakeholder suggestions when sensitivity cases are developed. In the past RTPs, sensitivities have been performed with various renewable generation output assumptions different from the base case analysis for both the on-peak and off-peak analysis and with high growth assumptions for West Texas oil and gas loads, extensive outage conditions, and winter peak load conditions. At the October 2022 Planning Working Group (PLWG) meeting, the potential challenges under the low solar near peak load condition[16] were discussed, which echoed what ERCOT has observed with the increased penetration of solar. ERCOT studied the low solar summer net peak load conditions in the 2023 RTP sensitivity analysis to help identify potential challenges under this assumed system condition. In addition, High Renewable Light Load condition was studied as an off-peak sensitivity. Though the High Renewable Light Load sensitivity was also performed in the 2020 and 2022 RTPs, with the significant amount of renewables added in the South and Coast Weather Zones in the 2023 RTP, this sensitivity was selected again to understand any potential changes introduced by the flow pattern change. The detailed assumptions and study results are summarized in the following sections and are also available in Appendices B and K, respectively.

3.2.1 ERCOT Low Solar Summer Net Peak Load Conditions

The on-peak sensitivity analysis was performed for years 2025 and 2028 under ERCOT coincident summer net peak load conditions. The focus of this sensitivity analysis was to test the robustness of the transmission projects identified under the summer peak load conditions and identify any additional reliability needs to reliably serve the net peak load when solar is ramping down rapidly in the early evenings.

The low solar cases started with the corresponding summer peak cases. Updates were then made to the start cases to represent the low solar net summer peak conditions.

- The 2023 ERCOT long-term load forecast coincident summer peak load was used as the starting point to derive the forecasted load for this sensitivity study. The starting load forecast was then adjusted by the large loads that were incorporated during the 2023 RTP load review process, the load impact from rooftop solar, and electrical vehicles. The adjusted load was then discounted to reflect the lower forecast when the solar ramps down compared with the summer peak condition. The total load studied for year 2028 is approximately 94 GW. The load values by Weather Zone and study year are shown in Table 2.

Table 2: Load Forecast for Summer Net Peak Load (Low Solar) Case (MW)

Year	Coast	East	Far West	North	North Central	South Central	Southern	West	Total
2025	22,823	2,785	10,804	4,482	25,237	13,413	6,346	2,871	88,762
2028	23,525	2,848	13,137	4,740	25,713	14,216	6,366	3,126	93,670

16 https://www.ercot.com/files/docs/2022/11/07/PLWG%20October%2019th%20quick%20draft%20white%20paper_.docx

- Renewable generation dispatch was set based on historical data analysis. The capacity factors used for renewable generation are shown in Table 3.

Table 3: Renewable Generation Capacity Factors

Solar	South Wind - Coastal	South Wind – Non-Coastal	Wind - Panhandle	Other Wind
13.26%	63.3%	70.9%	63.3%	33.6%

- Battery energy storage was dispatched up to 45.9% of their maximum capacity. The capacity factor was determined based on historical data analysis using similar methodology as the ERCOT Monthly Outlook for Resource Adequacy (MORA) report[17].

The study results showed that additional transmission upgrades were needed to ensure the reliable service of system demand under the low solar net summer peak load conditions. In this sensitivity study, the solar generation resources were dispatched up to 13.26% of their capacity compared with 79% in the summer peak cases. This led to less generation available in the West and Far West regions and resulted in more stress on the import paths so that additional import capability was needed to resolve the import issues. The majority of the identified additional transmission upgrades were located in the West and Far West regions. The study results also indicate that there is a need to accelerate the in-service date of several projects that had been previously identified as needed in later study years after 2025. In addition, the stage 3 project from the ERCOT Delaware Basin Load Integration study, i.e., New Riverton Switch - Owl Hill Sub 345-kV Line Addition and two 345/138-kV Transformer Additions at Owl Hill, was found to be needed to resolve the observed reliability violations in the Culberson loop area. The stage 3 project was needed in the 2022 RTP winter peak sensitivity analysis, as well, where the winter peak sensitivity case also represented a low solar high load system condition.

The low solar condition also resulted in more load in central Texas being served by the wind generation from south Texas, and the path facilitating the import from south to central Texas was overloaded. The South to Central Texas reliability project proposed for study year 2029 in the base case reliability study was needed to reliably serve the load in central Texas in the 2028 low solar summer net peak load condition.

The detailed results can be found in Appendix K.

3.2.2 High Renewable Light Load Conditions

Similar to the 2020 and 2022 RTP, the 2023 RTP includes analysis of high renewable dispatch under light load conditions. This off-peak sensitivity analysis was performed for year 2026. The 2026 minimum load case was used as the start case for this sensitivity. Both the renewable dispatch and the load level were updated based on the assumptions presented to the stakeholders at the October 2023 RPG meeting.[18]

[17] https://www.ercot.com/gridinfo/resource
[18] https://www.ercot.com/files/docs/2023/10/17/2023_rtp_sensitivity_assumptions_october_2023_rpg.pdf

In the high renewable off-peak sensitivity analysis, ERCOT started the case with 55 GW of renewable output. In order to respect various stability limits and the critical inertia level, the renewable output was reduced to approximately 50 GW, which corresponds to an 84% renewable penetration level. With this assumed penetration level, the “CPS San Antonio South Reliability Project” is needed to facilitate the export of the renewable generation from the South Weather Zone. In addition, multiple 345-kV line upgrades were needed outside of Houston to deliver the renewable generation, especially the solar generation west of the South Texas Project to WA Parish 345-kV line and south of the South Texas Project station. ERCOT also identified some additional local transmission solutions to facilitate wind and solar export, in addition to acceptable mitigation actions such as voltage schedule changes, tap setting changes, and generation re-dispatch other than wind and solar. Compared with the 2020 RTP, for which the local needs were concentrated in the South Weather Zone, and the 2022 RTP, which identified the transmission needs in multiple Weather Zones, including the West, South, and North Central Weather Zones, the transmission needs in 2023 RTP are mainly concentrated in the Coast, North Central, South Central, and South Weather Zones. The detailed results can be found in Appendix K.

All the reliability issues observed in high renewable light load conditions could be resolved by utilizing renewable curtailment. Since renewable curtailment is a valid mitigation action in operations and planning, the identified transmission solutions will serve as economic project candidates for further economic analysis, rather than being required for reliability purposes.

3.3. Short Circuit Analysis

As indicated in Section 2.2, ERCOT conducted short-circuit analysis for Resource Entity-owned facilities for 2026 summer peak conditions based on the system protection future year base case and shared the results with GOs. GOs reviewed the fault duty information to identify buses with over-dutied breakers and CAPs.

Table 4 provides a summary of the results of the short-circuit analysis. The study cases and details of the results can be found in Appendix L.

Table 4: Summary of Short-circuit Analysis

Magnitude of Fault Current	Number of buses (3-phase fault)	Number of buses (single-line-to-ground fault)
Below 40 kA	493	498
40 kA ~ 60 kA	60	48
More than 60 kA	0	7

3.4. Long Lead Time Equipment Analysis

In response to ERCOT’s request, TOs provided a list of long lead time equipment based on their spare equipment strategies. All TO-provided BES long lead time equipment outages were studied to determine the impact of unavailability of such equipment for an extended period of time. This analysis was conducted for 2025, 2028, and 2029 summer peak conditions, along with 2026 off-peak conditions. Overall, 33 unique 345/138-kV transformers, 3 unique 345/115-kV transformers, 1 unique

138-kV HVDC transformer, 18 unique 345-kV reactive devices, and 1 unique reactive device at other voltage levels, 2 345-kV synchronous condensers and their transformers, 2 unique 138-kV STATCOMs, 3 unique 345-kV SVCs, and 4 unique 138-kV SVCs were identified as long lead time equipment. NERC category P0, P1, and P2 planning events were studied. The results were shared with the respective TPs. The list of long lead time equipment and study results are provided in Appendix M.

4. Economic Analysis

The 2023 RTP economic analysis was performed using production cost simulation for years 2025 and 2028. In the analysis, both the production cost savings test and the generator revenue reduction test were utilized. Through this assessment, ERCOT identified transmission congestion and tested various transmission improvements to address this congestion in a cost-effective manner (as defined by ERCOT's economic planning criteria). Twenty economic transmission improvement projects were evaluated in the 2023 RTP. The tested transmission solutions did not meet either of the economic planning criteria.

The input data and congestion tables from the 2023 RTP can be found in Appendices D and E. Table 5 provides a system summary of 2023 RTP economic analysis for years 2025 and 2028.

Table 5: System Summary of 2025 and 2028[19]

Description	Unit	2025	2028
Coincident Peak Load	MW	91,251	95,918
Peak Net Load [20]	MW	73,199	78,935
Minimum Net Load [20]	MW	5,944	6,257
Annual Served Demand	GWh	525,556	569,969
Annual Storage Charging	GWh	3,218	3,575
Annual Transmission Losses	GWh	13,165	14,347
Annual Generation	GWh	541,939	587,891
Load-Weighted Average LMP	$/MWh	26.26	26.81

Figure 14 shows the renewable penetration for the 2025 and 2028 study years. Renewable penetration is defined as the total amount of demand at any given time that is served by wind and solar generation. It appears possible that there may be hours when all ERCOT demand could theoretically be served by wind and solar resources. However, thermal and stability constraints on the transmission system and unit commitment limitations caused the grid simulation software to curtail available wind and solar output. Figure 15 and Figure 16 summarize monthly production and curtailment for wind and solar generation, respectively.

[19] All results are based on the 2013 historical weather conditions
[20] Hourly Net Load = Hourly Load Forecast – Hourly Wind Output – Hourly Solar Output

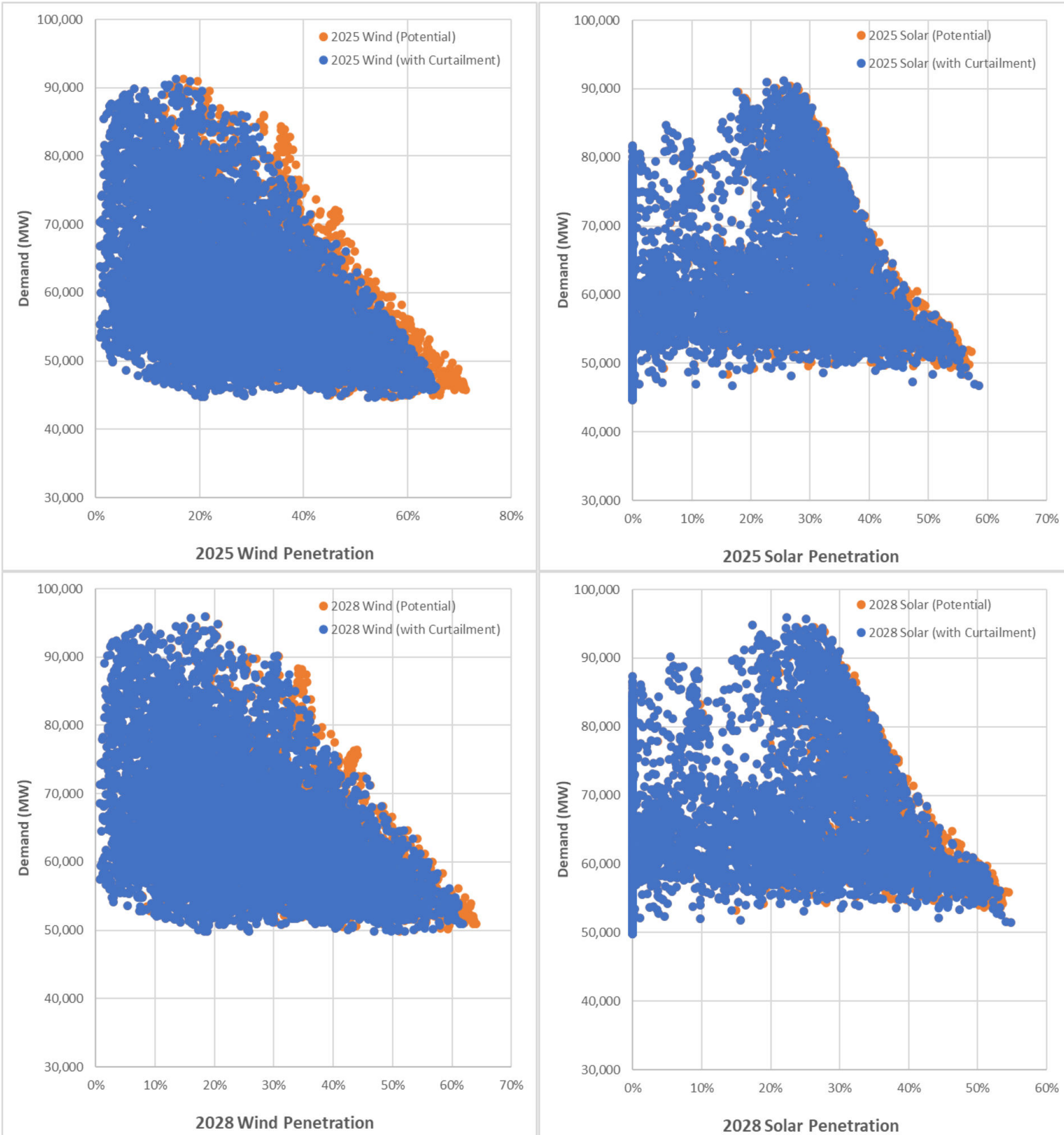

Figure 14: Wind and Solar Penetration

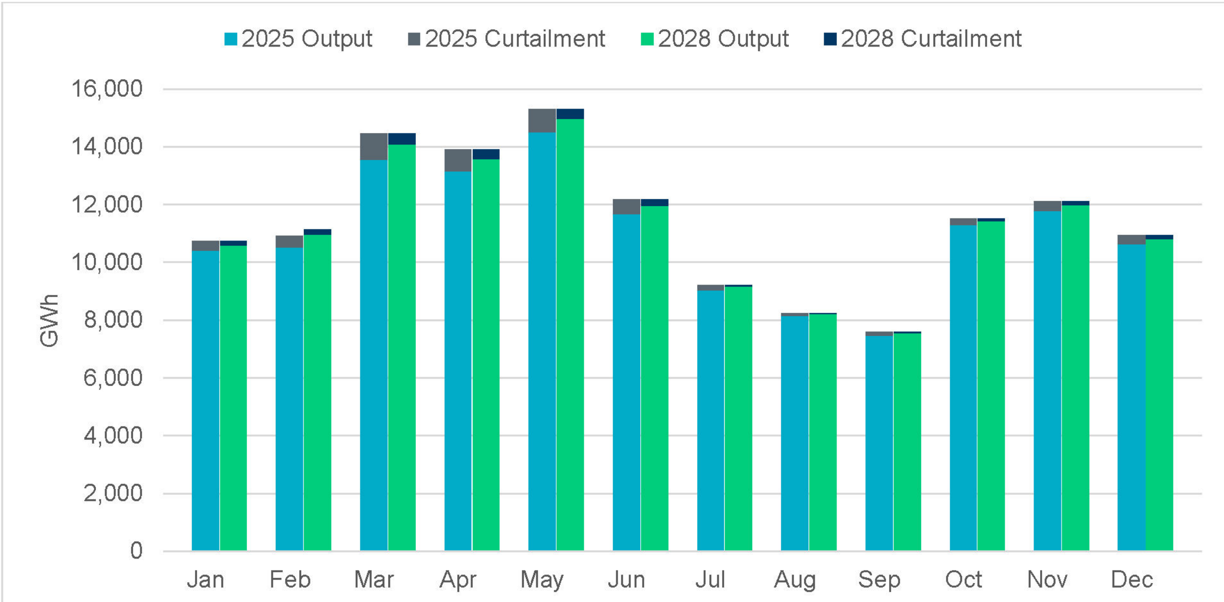

Figure 15: Wind Production and Curtailment

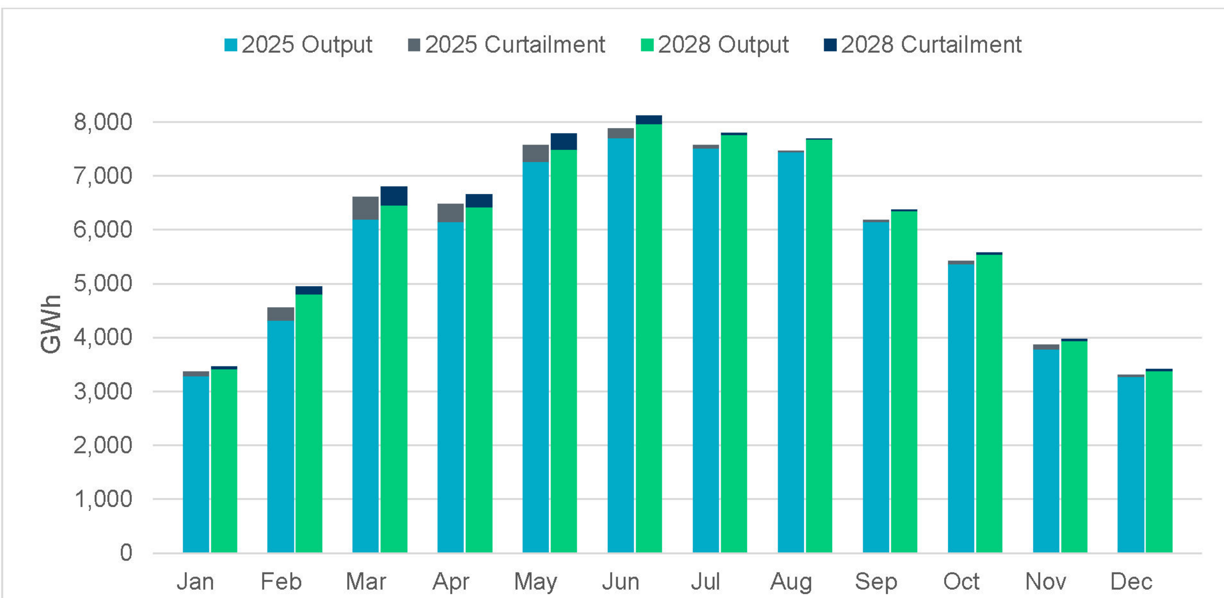

Figure 16: Solar Production and Curtailment

Figure 17 and Figure 18 show the top constraints seen in 2025 and 2028, respectively. The size of each bubble represents the relative capacity of each congested element over the study period.

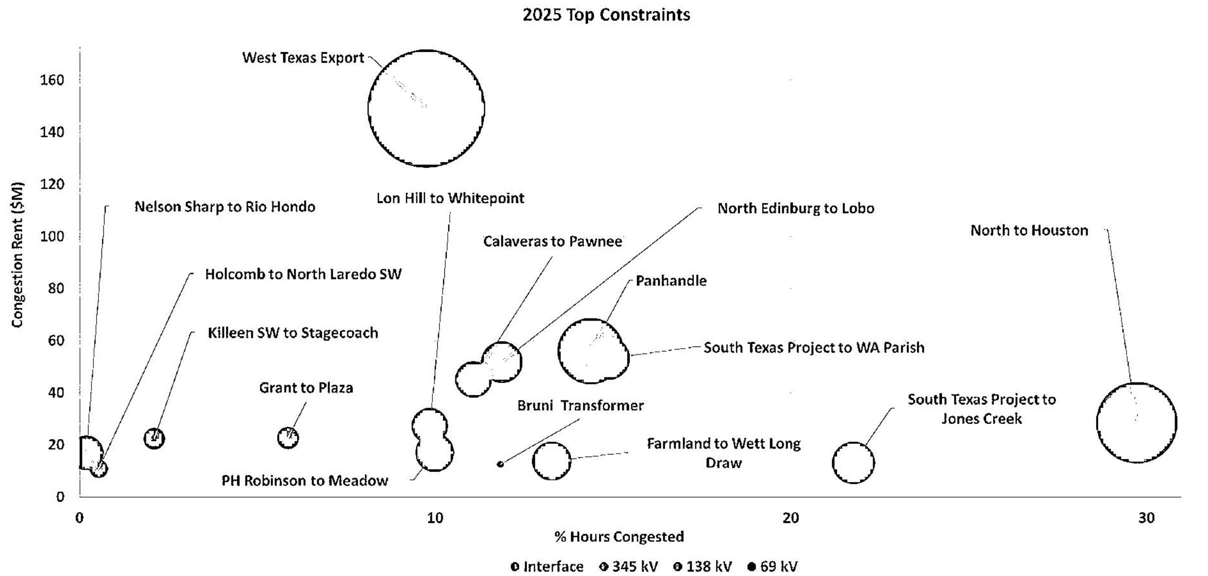

Figure 17: Top Constraints in 2025

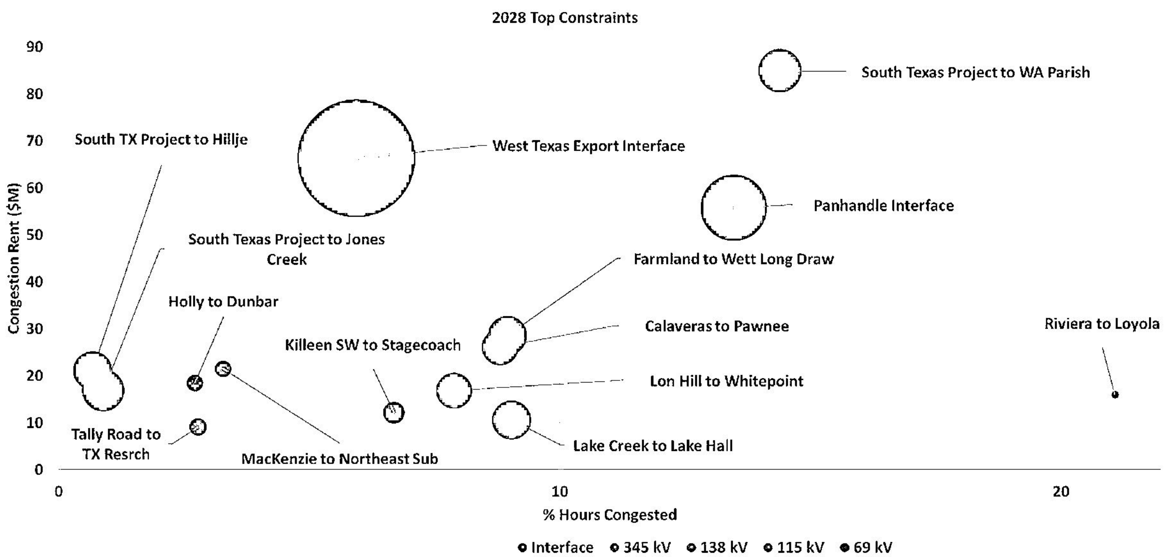

Figure18: Top Constraints in 2028[21]

Similar to the 2022 RTP economic analysis, the West Texas Export interface was the top congested element observed for both the 2025 and 2028 study years. The interface limit used in the 2023 RTP was 11,016 MW based on preliminary results from ERCOT's Long-Term West Texas Export Special Study[22]. The interface was congested approximately 9.75% and 5.94% of hours in the 2025 and 2028 study years, respectively. Driven by the load growth in West and Far West Texas, the congestion cost for West Texas Export interface was less in 2028 compared to 2025.

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[21] Trumbull Transformer with 43% of congested hours and $7.3M congestion rent is not illustrated in the graph.

[22] https://www.ercot.com/files/docs/2023/08/28/ERCOT-EV-Adoption-Final-Report.pdf

Different from the 2022 RTP study, the Panhandle interface limit was reintroduced in both 2025 and 2028 study years as more renewable resources are commissioned in the Panhandle region. Over $50 million of congestion cost was observed for both 2025 and 2028. To effectively alleviate congestion on the West Texas Export interface and/or Panhandle interface, the long-distance high voltage or direct current (DC) transmission lines are more favorable. However, these options are also expensive. A total of eight projects have been evaluated in 2023 RTP economic analysis and will be continuously analyzed in the future RTP and LTSA studies.

The North to Houston interface was modeled with hourly profiles based on historical data in the 2023 RTP economic analysis. A modest congestion was observed in both the 2025 and 2028 study years on the North to Houston interface, with the interface congested 14.87% and 4.19% of hours in the 2025 and 2028 study years, respectively. The congestion was driven by the increased renewable integration in North Central, East, and North Weather Zones. These results are consistent with real-time congestion on the North to Houston interface throughout 2023.

Due to the renewable generation increase in the Lower Rio Grande Valley (LRGV) area, North Edinburg to Lobo interface and Nelson Sharpe to Rio Hondo interface experienced high congestion in both real-time operations and the 2023 RTP economic study. It was observed that the North Edinburg to Lobo interface was congested 29.73% of hours in the 2025 study year. The Nelson Sharpe to Rio Hondo interface was congested 21.76% of hours in 2025. These observations are consistent with the findings identified by the 2022 RTP. Congestion in the area was driven primarily by the contingency involving the common-tower loss of the North Edinburg to Bonilla 345-kV line and the 138-kV line from Bonilla to South Santa Rosa. The primary 345-kV path was removed as part of the contingency, and the result was heavy congestion along the parallel 138-kV path to the west.

The ERCOT Board of Directors endorsed the LRGV System Enhancement Project in 2021. The Public Utility Commission of Texas (PUCT) also ordered the construction of a new second circuit on the double-circuit capable 345-kV transmission line that runs from San Miguel to Palmito and new transmission facilities to close the loop from Palmito to North Edinburg. These projects plan to be in operation before the summer of 2027. Those improvements help to relieve the congestion on the North Edinburg to Lobo interface and Nelson Sharpe to Rio Hondo interface in 2028.

A noticeable change in 2023 RTP study results is high congestion observed in the Coast Weather Zone in both 2025 and 2028. This is attributed to a combination of the addition of solar generation south of Houston, the increased new renewable generation in the South Weather Zone, and the load growth in Houston area. The South Texas Project to WA Parish 345 kV line was congested 11.88% and 14.39% of hours in 2025 and 2028, respectively.

In addition, the Calaveras to Pawnee 345 kV line was heavily congested in both 2025 and 2028. The ERCOT Board of Directors recently endorsed the San Antonio South Reliability Project (RPG Project ID: 22RPG048). This is the Tier 1 project with an in-service date of June 2027. This project helped to reduce the congestion cost on the Calaveras to Pawnee 345 kV line in 2028.

Finally, as required by ERCOT Protocols Section 3.10.8.4(3), ERCOT identified additional transmission elements that have a high probability of providing significant added economic efficiency to the ERCOT market using dynamic ratings. Dynamic ratings for the identified elements (listed in Appendix N) have been requested from the associated TOs.

4.1. Study Assumptions and Methodology

Pursuant to the amended 16 TAC § 25.101(b)(3)(A)(i), an economic cost-benefit study for economic projects must be performed under a congestion cost savings test and a production cost savings (PCS) test, and ERCOT is required to develop a congestion cost savings test in consultation with the Commission staff. While the congestion cost benefit test is being developed, § 25.101(b)(3)(A)(i)(I)(-b-) allows ERCOT to use the generator revenue reduction (GRR) test, which was used for evaluation of economically driven projects in the ERCOT Region during the 2006 to 2012 timeframe, as the congestion cost savings test. To pass the PCS test, the levelized ERCOT-wide annual PCS attributable to the proposed project should be equal to or greater than the first-year annual revenue requirement (13.2%) of the proposed project. To satisfy the GRR test requirement, the levelized ERCOT-wide annual GRR attributable to the proposed project should be equal to or greater than the average of the annual revenue requirement for the first three years (12.9%) of the proposed project. These revenue requirements are reviewed annually and may vary from year to year. ERCOT may recommend, and the Commission may approve, a transmission upgrade in the ERCOT Region that passes either a congestion cost savings test or a PCS test. The total production cost is the sum of the fixed operation and maintenance (O&M), startup, variable O&M, fuel, and emission cost of generators. The total generator revenue is equal to the sum of the energy production of the generator times its nodal price. Both the total production cost and the total generator revenue are adjusted to account for interchange adjustment, transmission violations, and the monetary value of voluntary demand curtailment in response to the price.

4.2. Top Constraints for 2025 and 2028 Study Years

The economic analysis continues to demonstrate significant congestion for both the 2025 and 2028 study years. Based on the review of the initial congestion pattern and stakeholder feedback, ERCOT selected transmission projects to conduct both the PCS test and the GRR test, as guided by the amended 16 TAC § 25.101(b)(3)(A)(i) outlined in section 4.1.

Table 6 shows the projected top 10 constraints ranked by the congestion rent on the ERCOT System based on the economic analysis conducted for the study years 2025 and 2028. Figure 19 shows locations of top 10 Constraints in 2025 and 2028.

Table 6: Top Congested Constraints from 2025 and 2028 Study Years

Index	Constraint	Congestion Rent[23] (M$)	
		2025	2028
1	West Texas Export Interface	$149M	$66M
2	South Texas Project to WA Parish 345-kV Line	$53M	$85M
3	Panhandle Interface	$56M	$56M
4	Calaveras to Pawnee Switching Station 345-kV Line	$45M	$26M
5	North Edinburg to Lobo Interface	$52M	NA
6	Lon Hill to Whitepoint 345-kV Line	$27M	$17M
7	Farmland to Wett Long Draw 345-kV Line	$14M	$29M
8	North to Houston Interface	$29M	$7M
9	South Texas Project to Jones Creek 345-kV Line	$13M	$17M
10	Grant to Plaza 138-kV Line	$23M	$6M

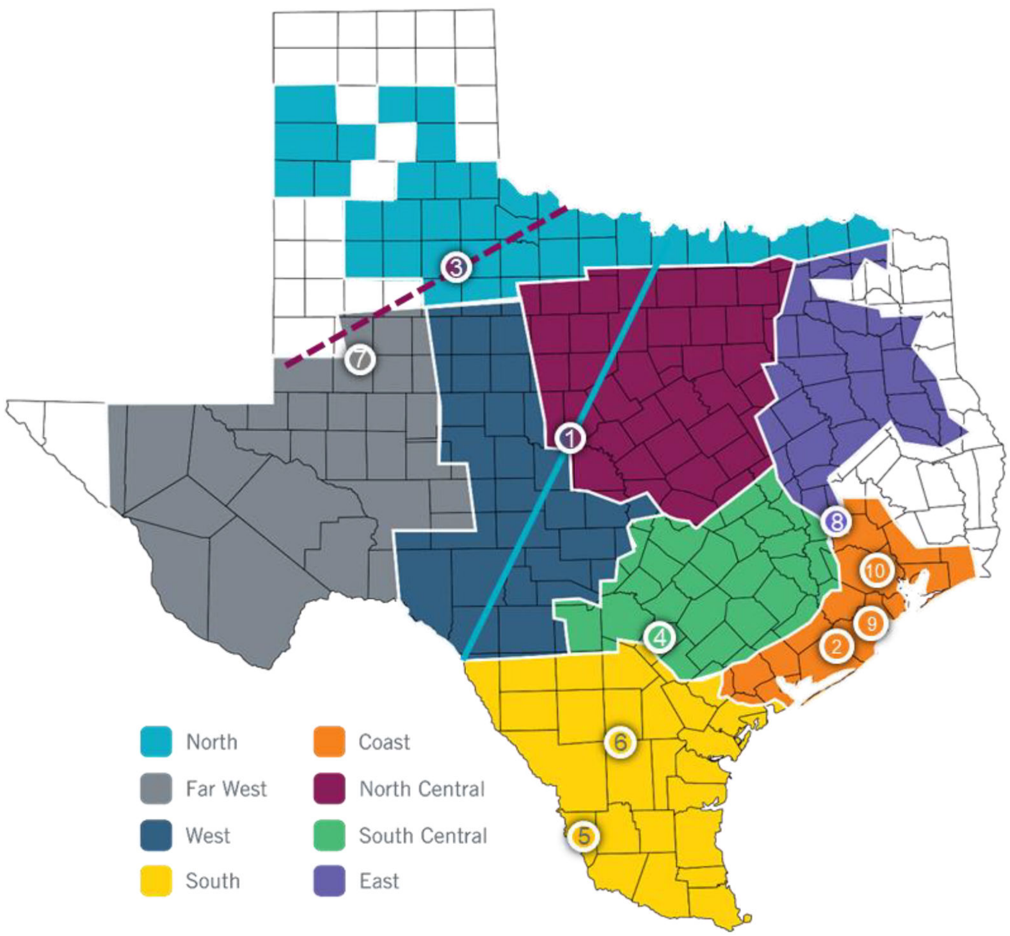

Figure 19: Locations of Top 10 Constraints in 2025 and 2028

[23] Congestion rent indicates areas of the system where economic transmission projects may be beneficial. It is not an indication of whether a project to reduce specific congestion would or would not meet the ERCOT economic planning criteria.

4.3. Projects Selected for Evaluation

The congestion patterns observed for the 2025 and 2028 study years served as the main basis for identifying potential economic projects for further evaluations. The West Texas Export Interface, Panhandle Interface, and South Texas Project to WA Parish 345-kV line were the top 3 congested paths in 2025 and 2028 study year while the congestion on the South Texas Project to WA Parish 345-kV line was the leading non-interface congestion. Calaveras to Pawnee Switching Station, Lon Hill to Whitepoint, Farmland to Wett Long Draw, and South Texas Project to Jones Creek 345-kV lines were among other top-congested lines.

In addition to the projected congestion outlined above, ERCOT also reviewed historical congestion observed in those areas and took its experiences with these constraints in past economic models into consideration to select several additional projects for further evaluation.

Table 7 shows the list of all transmission projects that were evaluated in this economic analysis. Figure 20 shows the location of each of the projects. Detailed descriptions of these projects are included in Appendix P.

Table 7: Projects Selected for Economic Evaluation

Index	Description
Project 1	4 AC lines proposed by Long -Term West Texas Export Study Report (LTWTX) plus the upgrade of the Nevill Road Switch to North McCamey and Bakersfield 345-kV line
Project 2	3 AC lines plus Tesla to King 1500 MW HVDC proposed by LTWTX plus the upgrade of the Nevill Road Switch to North McCamey and Bakersfield 345-kV line
Project 3	New White River to Long Draw and Black Water to Dermott double-circuit 345-kV lines
Project 4	New Tesla to Graham-Royse double-circuit 345-kV line
Project 5	New Tesla to King 1500 MW HVDC
Project 6	New Brown to Bell County East Switch double-circuit 345-kV line
Project 7	New Tesla to Marion 1500 MW HVDC
Project 8	New Tesla to WA Parish 1500 MW HVDC
Project 9	Loyola to Driscoll 69-kV area upgrades
Project 10	Lon Hill to Angstrom 345-kV line upgrade
Project 11	Farmland to Wett Long Draw 345-kV line upgrade
Project 12	Lubbock Area 115-kV line upgrades
Project 13	WA Parish to Obrien 345-kV line upgrade
Project 14	New South Texas Project to Bailey to Ph Robinson 345-kV lines
Project 15	Killeen Area 138-kV line upgrades
Project 16	South Texas Project to Hillje 345-kV double circuit line upgrade
Project 17	Lewisville- Dunham 345-kV line upgrade
Project 18	San Miguel to Marion 345-kV double-circuit line upgrade
Project 19	South to Central Texas reliability project
Project 20	Coast Area 345-kV line upgrades and additions

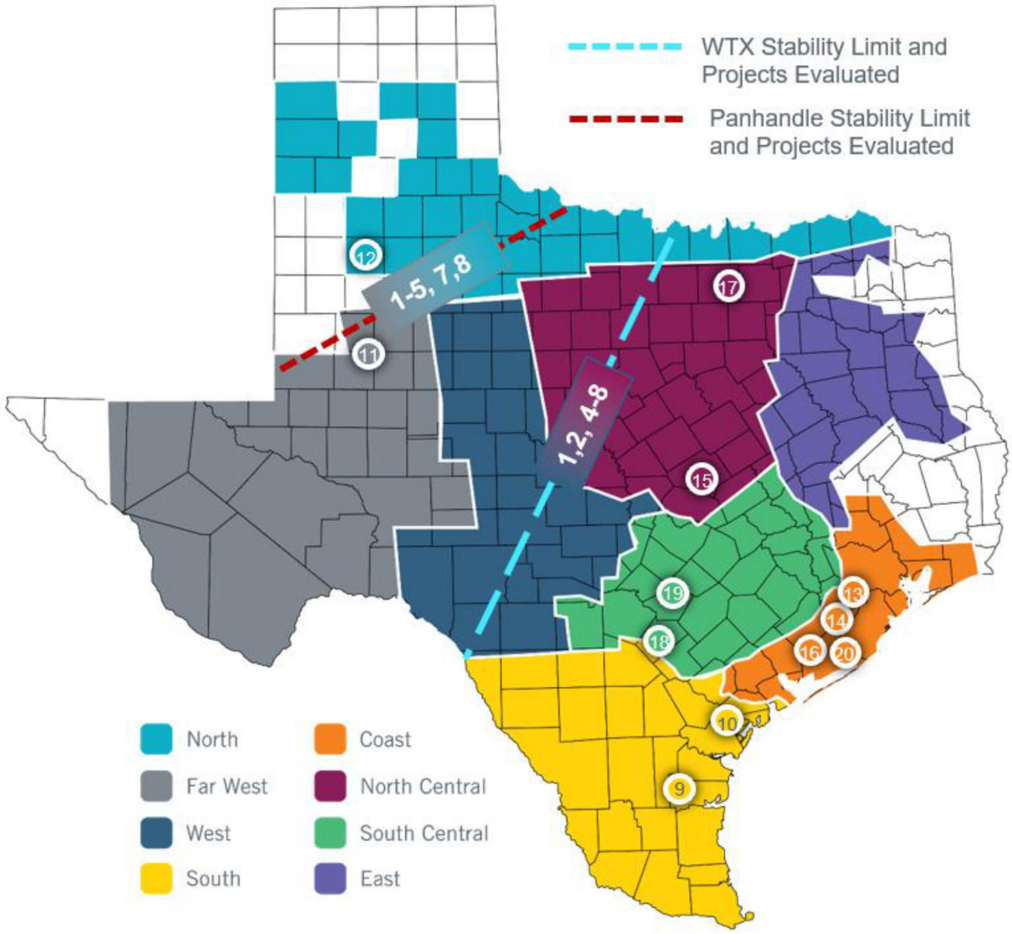

Figure 20: Proposed Project Locations

4.4. Project Evaluation Results

Using the updated 2023 RTP economic cases (both 2025 and 2028 study year cases), ERCOT performed an economic benefit-cost analysis for 20 transmission enhancements chosen based on a review of the initial congestion patterns and historical data. For all transmission upgrades, both the PCS test and the GRR test were performed and a break-even capital cost, if appliable, was provided.

ERCOT evaluated, for informational purposes, the benefit/cost ratio for both the PCS and GRR tests using a generic cost estimate. A transmission system upgrade is economically viable if 1) it meets the PCS test or 2) it meets the GRR test requirement without adversely impacting the overall societal benefit.

Details of the economic analysis can be found in Appendix P.

5. Appendices

Index	Description	Document	Access
A	RTP Scope and Process Document	Appendix_A_2023_RTP_Scope_and_Process_Final.pdf <file included in the public version>	Public
B	Input assumptions for the 2023 RTP reliability analysis	Appendix_B_2023_RTP_Reliability_Input_Assumptions.xlsx <file included in the public version>	Public
C	WFW IHS new load interconnection	Appendix_C_2023_RTP_WFW_IHS_New_Load_Interconnection.xlsx <file available in MIS Secure Area>	MIS Secure
D	Input assumptions for the 2023 RTP economic analysis	Appendix_D_2023_RTP_Economic_Input_Assumptions.xlsx <file included in the public version>	Public
E	Economic analysis start case inputs and annual constraints	Appendix_E_2023_RTP_Economics_Start_Case_Inputs_Annual_Contraints.zip <file available in MIS Secure Area>	MIS Secure
F	Reliability Driven Projects	Appendix_F_2023_RTP_Reliability_Projects_Public.xlsx <file included in the public version>	Public
G	Project locations	Appendix_G_2023_RTP_Project_Locations.pdf <file included in the public version>	Public
H	Constraint Management Plans	Appendix_H_2023_RTP_Constraint_Management_Plans.xlsx <file available in MIS Secure Area>	MIS Secure
I	Multiple element contingency analysis	Appendix_I_2023_RTP_MultipleElementContingencyStudyReport.docx <file is ERCOT-Confidential>	N/A
J	Facilities loaded over 95%	Appendix_J_2023_RTP_95%_Exceedance_PG31123.xlsx <file available in MIS Secure Area>	MIS Secure
K	Sensitivity Analysis Results	Appendix_K_2023_RTP_Sensitivity_Projects.xlsx <file available in MIS Secure Area>	MIS Secure
L	Short circuit Analysis	Appendix_L_2023_RTP_ShortCircuitStudyCases_DetailedResults.docx <file available in MIS Secure Area>	MIS Secure
M	Long lead time equipment analysis	Appendix_M_2023_RTP_LongLeadTimeEquipment.docx <file is ERCOT-Confidential>	N/A
N	Transmission elements proposed to be dynamically rated	Appendix_N_2023_RTP_Dynamic_Rating_NP3_10_8_4.xlsx <file available in MIS Secure Area>	MIS Secure
O	Minimum Deliverability Analysis	Appendix_O_2023_RTP_Minimum_Deliverability_Projects.xlsx <file available in MIS Secure Area>	MIS Secure
P	Economic Analysis Results	Appendix_P_2023_RTP_Economic_Analysis.pdf <file included in the public version>	Public

non-residential purposes at primary distribution voltage levels of between 12 and 60kV. The rate schedule sets forth the Monthly Rate (composed of the Customer Charge, the Metering Charge, the Distribution System Charge and Transmission System Charge), the service riders that may apply to the rate schedule, the method for determining the customer's billing demand, and the Company's general terms of service under this rate schedule.

Q. PLEASE DESCRIBE ANY PROPOSED CHANGES TO THE DELIVERY SYSTEM CHARGES IN THE PRIMARY SERVICE RATE SCHEDULE.

A. CenterPoint Houston is proposing to update the delivery system charges in this rate schedule to reflect the revenue requirement by function as determined by the Proposed CCOSS.

Q. PLEASE DESCRIBE THE TRANSMISSION SERVICE RATE SCHEDULE.

A. This rate schedule is available to retail customers requesting delivery service for non-residential purposes at transmission voltage levels (greater than 60kV). The rate schedule sets forth the Monthly Rate (composed of the Customer Charge, the Metering Charge, the Distribution System Charge and Transmission System Charge), the service riders that may apply to the rate schedule, the method for determining the customer's billing demand, and the Company's general terms of service under this rate schedule.

Q. PLEASE DESCRIBE ANY PROPOSED CHANGES TO THE TRANSMISSION SERVICE RATE SCHEDULE.

A. CenterPoint Houston is proposing to update the delivery system charges in this rate schedule to reflect the revenue requirement by function as determined in the

Proposed CCOSS. Additionally, the Company is proposing to add language to the Transmission Service Rate Schedule to include a Load Study Charge for customers requesting delivery service under this Rate Schedule for a new or added load of 10 MW or more.

Q. WHY IS CENTERPOINT HOUSTON IMPLEMENTING A CHARGE FOR LOAD STUDIES OVER 10MW?

A. CenterPoint Energy saw a large increase in load customer requests in 2023. In addition, the sizes of many of the load customer requests were at unprecedented sizes which increases the study complexity greatly as transmission upgrades are much more likely. CenterPoint Energy already charges a fee for generator interconnection studies which require similar studies be performed. CenterPoint Houston has proposed the Load Study Charge to ensure all customers requesting studies are treated equally, regardless of whether they are wholesale customers like generators or retail customers. The charge for load customer studies will also aid in our effort to weed out customers requesting a Load Study that do not have serious plans to start their project.

Q. WHAT WILL CENTERPOINT HOUSTON CHARGE CUSTOMERS FOR A LOAD STUDY?

A. CenterPoint Houston charges a $50,000 baseline fee to conduct a load study. If CenterPoint Houston and/or ERCOT require a stability analysis, an additional $50,000 fee applies.

Q. HOW WAS THE $50,000 MINIMUM CHARGE DETERMINED?

A. The Company used the flat fee already charged for generator full interconnection study ("FIS") of $100,000. The FIS consists of four component studies: a steady-state study, short circuit study, a stability study, and a facility study. The stability study, which is not typically required for load studies, takes about as much time to complete as the other three FIS components combined. Consequently, CenterPoint has proposed to set the Load Study fee at $50,000 unless a stability study is required, in which case the Company would charge the customer an additional $50,000.

Q. WILL THE LOAD STUDY CHARGE BE REFUNDABLE?

A. No. The Company does not intend to refund the fee for customers who ultimately build or decide not to build their facilities.

Q. PLEASE DESCRIBE THE STREET LIGHTING SERVICE ("SLS") WITHIN THE LIGHTING SERVICES RATE SCHEDULE.

A. SLS is available to cities, governmental agencies, real estate developers, and other groups requesting the installation of street lighting. SLS provides for the installation, ownership, and maintenance of street light systems and fixtures, which may be affixed to existing distribution poles, if available, or to ornamental poles specifically installed by the Company for the street light fixtures (referred to as "ornamental standards" in the SLS rate schedule), and the delivery of electric power and energy to such fixtures on an unmetered basis. The majority of the cost for providing this service are CenterPoint Houston's installation costs of the systems, i.e., capital investment, and maintenance expenses associated with the specific lighting fixture. This rate schedule contains provisions governing the terms of service and the type of street lighting systems available, the Monthly Rate

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
PUC DOCKET NO. 56211
SOAH DOCKET NO. 473-24-13232

TEXAS INDUSTRIAL ENERGY CONSUMERS
REQUEST NO.: TIEC-RFI04-07

QUESTION:

Referring to page 28, line 14-16, did CEHE consider other methods for managing customer load requests other than a non-refundable fee so that CEHE can "weed out customers requesting a Load Study that do not have serious plans to start their project?" If so, please provide the other methods considered and the study between the methods that show this is best or only method that will accomplish the goal.

ANSWER:

Prior to implementation of a load study fee, another method employed by the Company was to only require customers to complete a load data request form in its entirety in order to initiate a load study. This had minimal impact on weeding out customers that were not serious about moving forward into the detailed design and construction phase once a study has been completed. Customers could request the Company to study multiple interconnection locations and varying levels of proposed load, which resulted in additional resources to perform analysis of the permutations.

Since implementing a load study fee, customers are encouraged to firm up their interconnection requests, leading to a reduction of study iterations and enabling the Company to complete studies in a more timely fashion.

SPONSOR:
Harris, Rina; Mercado, David L;

RESPONSIVE DOCUMENTS:
None

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC
PUC DOCKET NO. 56211
SOAH DOCKET NO. 473-24-13232

TEXAS INDUSTRIAL ENERGY CONSUMERS
REQUEST NO.: TIEC-RFI04-05

QUESTION:

Referring to page 28, line 7-10, please provide the 10 MW and greater customer load request data for 2019, 2020, 2021, 2022, and 2023. Each request should include name, location, MW, construction cost, proj ected ready-for-use date, and which Load Study Charges would have applied if this tariff was in place. For each year, categorize the project status into Requested, Under FEA Contract, In Active Construction, and Complete. If CEHE already has substantially similar categorizations for proj ect tracking, then substitution of internal categories is acceptable.

ANSWER:

Reference attachment.

The below attachment is highly sensitive/protected material and is being provided pursuant to the Protective Order issued in Docket No. 56211

SPONSOR:
Harris, Rina; Mercado, David L;

RESPONSIVE DOCUMENTS:
TIEC-RFI04-05_Historical Load Study Data_050824 (HSPM).xlsx

ENTERGY TEXAS, INC. Electric Service EXTENSION POLICY	Sheet No.: 18 Effective Date: Service on and after 10-17-18 Revision: 6 Supersedes: Revision Effective 4-1-14 Schedule Consists of: Three Sheets

ELECTRIC EXTENSION POLICY

This Electric Extension Policy shall apply only to those facilities that Company will construct and maintain in order to provide electric service to its Customer.

I. NEW LOAD OF LESS THAN 2500 KW

For (a) residential Customers with any new and additional load and (b) Customers which, unless otherwise agreed to by Company, are Customers with a Contract Demand of new and additional load ("New Load") of less than 2500 kW, the Company will extend and/or modify its overhead facilities, including infrastructure improvements required to provide electric service to the Customer but excluding Customer-specific substation(s) and System Improvements as defined below ("New Facilities"), necessary to serve new and permanent Customers, or additional load of an existing Customer to Customer's Point of Delivery, as agreed upon by the Company and the Customer, under the following terms:[1]

(A) (1) The Customer will not be required to reimburse the Company for New Facilities when Anticipated Revenues for the first four years of the contract term (if a contract is entered), or for the first four years after electric service associated with the New Load is provided (if no contract is entered) is equal to or exceeds the Company's Projected Investment in New Facilities necessary to serve the New Load. Anticipated Revenues are defined as projected annual non-fuel firm rate schedule revenues, plus base rate cost recovery mechanisms. Existing and future non-base rate cost recovery mechanisms applicable to the firm rate schedules under which the Customer receives service are not to be included in Anticipated Revenue.

(2) If a minimum bill is required by Company, the Customer and Company will enter either a minimum bill agreement or an Agreement for Electric Service which shall contain provisions for a monthly minimum bill for New Load at the greater of, as applicable, (a) 1/48th of the Anticipated Revenues for the first four years of the contract term for New Load, or (b) the Net Monthly Bill provision of the Customer's firm rate schedule plus base rate cost recovery mechanisms, less the Fixed Fuel Factor per Schedule FF and all non-base rate cost recovery mechanisms applicable to the firm rate schedules under which the Customer receives service for the New Load, or (c) the contracted monthly minimum bill for the New Load, to include all base rate cost recovery mechanisms, and such other terms as agreed to by the Company and the Customer that provide for an adequate assurance of revenue to pay for the New Facilities. In all cases, the Fixed Fuel Factor per Schedule FF and all non-base rate cost recovery mechanisms applicable to the firm rate schedules for which the Customer receives service shall be applied to the resulting bill.

(3) The Company may require the Customer to provide and maintain financial security, including at the sole discretion of the Company a parental guarantee, in a form that is mutually acceptable to the Customer and the Company, on revenue justified New Facilities until all Anticipated Revenues have been collected.

[1] Some pre-construction costs may be handled separately based on the scope of the project.

(Continued on reverse side)

(4) If the Customer's reimbursement obligation is based on an estimate of the cost of New Facilities that is equal to or greater than $100,000 or the Company elects to apply the true-up option at its sole discretion, the Company will true-up the estimated New Facilities costs to actual costs, and the Company or the Customer, as may be applicable, will pay to the other, the true-up amount[2] within 60 days of notice to the Customer of the true-up amount (including all applicable tax gross-up costs).

(B) (1) The Customer will be required to reimburse the Company for the cost of New Facilities when the Anticipated Revenues for the first four years of the contract term (if a contract for New Load is entered) or for the first four years after electric service associated with the New Load is provided (if no contract is entered) are less than the Company's Projected Investment in New Facilities necessary to serve the New Load. The Customer will, prior to the start of construction, reimburse the Company for any cost for New Facilities (including all applicable tax gross-up costs) that exceeds the Anticipated Revenues for the first four years of the contract term.

(2) If a minimum bill is required by the Company, the Customer's monthly minimum bill for the New Load shall be the greater of, as applicable, (a) 1/48th of the Anticipated Revenues for the first four years of the contract term for the New Load, or (b) the Net Monthly Bill provision of the Customer's firm rate schedule plus base rate cost recovery mechanisms, less the Fixed Fuel Factor per Schedule FF and all non-base rate cost recovery mechanisms applicable to the firm rate schedules under which the Customer receives service for the New Load, or (c) the contracted monthly minimum bill for the New Load, to include all base rate cost recovery mechanisms, and such other terms as agreed to by the Company and the Customer that provide for an adequate assurance of revenue to pay for the New Facilities. In all cases, the Fixed Fuel Factor per Schedule FF and all non-base rate cost recovery mechanisms applicable to the firm rate schedules for which the Customer receives service shall be applied to the resulting bill.

(3) The Company may require the Customer to provide and maintain financial security, including at the sole discretion of the Company a parental guarantee, in a form that is mutually acceptable to the Customer and the Company, on revenue justified New Facilities until all Anticipated Revenues have been collected. The Company may also require the Customer to provide and maintain financial security, acceptable to the Company, equal to the amount of any cost for New Facilities subject to reimbursement.

(4) If the Customer's reimbursement obligation is based on an estimate of the cost of New Facilities that is equal to or greater than $100,000 or the Company elects to apply the true-up option at its sole discretion, the Company will true-up the estimated facility costs to actual costs, and the Company or the Customer, as may be applicable, will pay to the other, the true-up amount[3] within 60 days of notice to the Customer of the true-up amount (including all applicable tax gross-up costs).

(5) The reimbursement obligation for the cost of New Facilities (and the minimum bill, financial security, and true up provisions applicable thereto) shall extend to the entire cost of New Facilities (including all applicable tax gross-up costs) that are no longer revenue justified under Section I Paragraph (A) above due to an increase in the actual or estimated cost of New Facilities and a decrease in the actual or expected Anticipated Revenues, or either of them.

[2] Customer refund not to exceed the amount of total reimbursement (including all applicable tax gross-up costs) paid by the Customer.
[3] Customer refund not to exceed the amount of total reimbursement (including all applicable tax gross-up costs) paid by the Customer.

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ENTERGY TEXAS, INC. Electric Service EXTENSION POLICY	Sheet No.: 18A Effective Date: Service on and after 10-17-18 Revision: 6 Supersedes: Revision Effective 4-1-14 Schedule Consists of: Three Sheets

ELECTRIC EXTENSION POLICY

(C) (1) When the required ratio is not satisfied by original Customers applying for service, but the Project Investment is to be made in a growing area and the Company feels that the development therein will produce a ratio of 4 to 1 or less in three (3) years, such facilities will be built without cost to Customers.

(2) The Company's Projected Investment will include the total investment in the New Facilities including, but not limited to, material costs, labor costs, labor cost adders, costs associated with third party vendors and consultants, costs associated with the procurement of real property rights, costs associated with securing all necessary approvals, taxes, capital suspense charges, overheads and associated tax gross-up charges, less any investment included in the total investment which should be charged to " System Improvements" and less any nonrefundable lump sum payments covered under the Policy on Service to Small Three-phase Loads. System Improvements are defined as those Entergy transmission projects (A) included in (1) Appendix A of MISO's Transmission Expansion Plan, or (2) Target Appendix A of MISO's Transmission Expansion Plan (subject to MISO's timely approval) (said (1) or (2) being referred to as "Entergy System Improvement Projects") and (B) whose construction has commenced or is scheduled to commence within five (5) years of Customer's execution of Company's required document(s) relating to this Policy. However, System Improvements shall not include those Entergy System Improvement Projects to be constructed solely due to Customer's New Load. In the event MISO's Transmission Expansion Plan is no longer applicable to Company, System Improvements shall be defined as those transmission upgrades in Company's five-year transmission plan that are expected to be owned by Company.

II. NEW LOAD EQUAL TO OR GREATER THAN 2500 KW

For large commercial and industrial customers, which, unless otherwise agreed to by Company, are customers with a Contract Demand of at least 2500 kW, the Company will extend and/or modify its overhead facilities, including infrastructure improvements required to provide electric service to the Customer but excluding customer-specific substation(s) and System Improvements as defined above ("New Facilities"), necessary to serve new and permanent customers, or additional load of an existing customer to customer's Point of Delivery (the new and additional load being collectively referred to as "New Load"), as agreed upon by the Company and the Customer, under the following terms:[4]

(A) (1) The Customer will not be required to reimburse the Company for New Facilities when projected Contract Revenues for the first four years of the contract term for New Load is equal to or exceeds the Company's Projected Investment (as defined in Section I) in New Facilities necessary to serve the New Load. Contract Revenues are defined as projected annual non-fuel firm rate schedule revenues, plus base rate cost recovery mechanisms. Existing and future non-base rate cost recovery mechanisms

[4] Some pre-construction costs may be handled separately based on the scope of the project.

(Continued on reverse side)

applicable to the firm rate schedules under which the Customer receives service are not to be included.

(2) If a minimum bill is required by Company, the Customer and Company will enter an Agreement for Electric Service which shall contain provisions for a monthly minimum bill for New Load at the greater of (a) 1/48th of the Contract Revenues for the first four years of the contract term for New Load, or (b) the Net Monthly Bill provision of the Customer's firm rate schedule plus base rate cost recovery mechanisms, less the Fixed Fuel Factor per Schedule FF and all non-base rate cost recovery mechanisms applicable to the firm rate schedules under which the Customer receives service for the New Load, or (c) the contracted monthly minimum bill for the New Load, to include all base rate cost recovery mechanisms, and such other terms as agreed to by the Company and the Customer that provide for an adequate assurance of revenue to pay for the New Facilities. In all cases, the Fixed Fuel Factor per Schedule FF and all non-base rate cost recovery mechanisms applicable to the firm rate schedules for which the Customer receives service shall be applied to the resulting bill.

(3) The Company may require the Customer to provide and maintain financial security, including at the sole discretion of the Company a parental guarantee, in a form that is mutually acceptable to the Customer and the Company, on revenue justified New Facilities until all projected Contract Revenues have been collected.

(4) If the Customer's reimbursement obligation is based on an estimate of the cost of New Facilities, the Company will true-up the estimated facility costs to actual costs, and the Company or the Customer, as may be applicable, will pay to the other, the true-up amount[5] within 60 days of notice to the Customer of the true-up amount (including all applicable tax gross-up costs).

(B) (1) The Customer will be required to reimburse the Company for the cost of New Facilities when the projected Contract Revenues for the first four years of the contract term for New Load are less than the Company's Projected Investment in New Facilities necessary to serve the New Load. The Customer will, prior to the start of construction, reimburse the Company for any cost for New Facilities (including all applicable tax gross-up costs) that exceeds the projected Contract Revenues for the first four years of the contract term. Construction shall be deemed to start when any equipment for the New Facilities is ordered by the Company.

(2) If a minimum bill is required by Company, the Customer and Company will enter an Agreement for Electric Service which shall contain provisions for a monthly minimum bill for the New Load at the greater of (a) 1/48th of the Contract Revenues for the first four years of the contract term for the New Load, or (b) the Net Monthly Bill provision of the Customer's firm rate schedule plus base rate cost recovery mechanisms, less the Fixed Fuel Factor per Schedule FF and all non-base rate cost recovery mechanisms applicable to the firm rate schedules under which the Customer receives service for the New Load, or (c) the contracted monthly minimum bill for the New Load, to include all base rate cost recovery mechanisms, and such other terms as agreed to by the Company and the Customer that provide for an adequate assurance of revenue to pay for the New Facilities. In all cases, the Fixed Fuel Factor per Schedule FF and all non-base rate cost recovery mechanisms applicable to the firm rate schedules for which the Customer receives service shall be applied to the resulting bill.

[5] Customer refund not to exceed the amount of total reimbursement (including all applicable tax gross-up costs) paid by the Customer.

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ELECTRIC EXTENSION POLICY

(3) The Company may require the Customer to provide and maintain financial security, including at the sole discretion of the Company a parental guarantee, in a form that is mutually acceptable to the Customer and the Company, on revenue justified New Facilities until all projected Contract Revenues have been collected. The Company may also require the Customer to provide and maintain financial security, acceptable to the Company, equal to the amount of any cost for New Facilities subject to reimbursement.

(4) If the Customer's reimbursement obligation is based on an estimate of the cost of New Facilities, the Company will true-up the estimated facility costs to actual costs, and the Company or the Customer, as may be applicable, will pay to the other, the true-up amount[6] within 60 days of notice to the Customer of the true-up amount (including all applicable tax gross-up costs).

(5) The reimbursement obligation for the cost of New Facilities (and the minimum bill, financial security, and true up provisions applicable thereto) shall extend to the entire cost of New Facilities (including all applicable tax gross-up costs) that are no longer revenue justified under Section II Paragraph (A) above due to an increase in the actual or estimated cost of New Facilities and a decrease in the actual or expected Contract Revenues, or either of them.

(6) If the Company is reimbursed more than $10,000,000 (including all applicable tax gross-up costs) by a Customer per Section II Paragraph (B)(1) above, and more large commercial or industrial customers are served by the New Facilities within a four-year period following Construction as defined in Section II Paragraph (B)(1) above, then the initial Customer that reimbursed the Company shall be entitled to receive a prorated refund of the reimbursement for common facilities (a) when additional large commercial or industrial customers execute an agreement for electric service within the four-year period following Construction as defined in Section II Paragraph (B)(1), and, (b) upon fulfillment of the refund process described in Section II Paragraph (B)(7) below. The Company will collect the full amount identified in Section II Paragraph (B)(1) above from the initial Customer.

(7) When requested by the initial Customer and after payment from the additional large commercial or industrial customer(s), a refund of reimbursement for common facilities to the initial Customer will be made on a pro-rata share of the amount initially paid by the initial Customer from each additional large commercial or industrial customer to be served by the New Facilities within the four-year period following Construction as defined in Section II Paragraph (B)(1), or until the capacity of the New Facilities is fully utilized, whichever comes first.[7] The additional large commercial or industrial customer(s) shall be obligated to make a payment to the Company for its pro rata share of New Facilities within 60 days of demand for such payment.

[6] Customer refund not to exceed the amount of total reimbursement (including all applicable tax gross-up costs) paid by the Customer.
[7] Customer refund not to exceed the amount collected by Company from additional customer(s).

(Continued on reverse side)

(8) When Customer is required to reimburse Company for New Facilities, Company shall provide reasonably detailed information setting forth the cost of the New Facilities as soon as practicable after receiving a request from Customer.

6.1.2.2.1 FACILITIES EXTENSION SCHEDULE

TERMS AND CONDITIONS

Schedule 6.1.2.2.1 addresses the costs associated with extension of Delivery System facilities under Section 5.7 of the Tariff. For purposes of this Schedule, whenever the context requires, the term "Retail Customer" includes property owners, builders, developers, contractors, government entities, authorized agent for the ultimate consumer, or any other organization, entity, or individual making the request to the Company for the extension of electric facilities and the installation of Billing Meter(s) for delivery service.

This schedule is applicable to all costs up to the service transformer, provided that the Retail Customer is not requesting an oversized transformer(s) or three-phase service when the load does not meet the minimum requirements. The Retail Customer will be responsible for the incremental increase in costs associated with requests for oversized facilities, three-phase service when the load does not meet the minimum requirements, or facilities in excess of what the Company would normally use to provide the service. The costs for the one standard meter, one set of service conductors (residential service conductors may be either overhead or up to 90 feet of underground conductors as measured horizontally along the route of the service), and properly sized transformation are provided for in the applicable base tariff schedule under which delivery service will be provided.

Modifications to, and/or re-routes of existing facilities outside of extending electric delivery service to the Retail Customer making the request, are addressed in Section 6.1.2.2 of this Tariff.

This Schedule is not applicable to interconnections with qualifying facilities (cogenerators or small power producers) or distributed generators, except for the section titled "Retail Customer-Owned Substation," which is applicable to qualifying facilities. Sections 6.1.2.3 and 6.1.2.4 of this Tariff address facilities extension for service to those Customers.

Retail Customers must satisfy all applicable state and municipal laws and regulations, including Local Gov. Code Sec. 212 or 232 for residential customers and appropriate provisions of the Tariff prior to construction by the Company.

Electric delivery service will be provided utilizing construction facilities and routes that are the most cost efficient for providing delivery service. Delivery service will typically consist of one radial feed, supplying one Point of Delivery at one standard service voltage applicable for the Rate Schedule under which the Retail Customer will receive electric delivery service.

Electric delivery service to residential and non-residential secondary voltage Retail Customers where permanently installed motor loads do not meet the minimum load requirements for three-phase connection as set out in Section 6.2.3.4 of the Tariff, will be single-phase. A request for three-phase service by a residential Retail Customer or a non-residential Retail Customer that does not meet the permanently installed motor load requirements will only be provided with the Company's approval and will require the Retail Customer to share in the cost of the excess facilities according to the terms of this Policy.

Retail Customer requests for excess facilities may require the Retail Customer to pay a one-time, non-refundable, contribution in aid to construction (CIAC) to share in the cost of providing the requested service. Excess facilities shall include, but are not limited to, the use of construction methods or facilities that have a higher cost than the methods or facilities the Company would normally provide, delivery service requiring a longer route than necessary, oversized facilities, redundant facilities, three-phase service for loads that do not meet the minimum requirements, any non-standard voltage(s), or conversion from overhead to underground electric delivery service. If a Retail Customer requests electrical delivery service for two (2) or more voltage classes, each voltage class delivery service will be considered as a separate Retail Customer request for the purpose of application of this Schedule. Any Retail Customer requests for electric delivery service that is anticipated to be temporary as described in this Policy will be provided only with the Company's approval and the Retail Customer may be required to share in the cost of constructing and removing the facilities extension required to satisfy the Retail Customer's request.

<u>DISTRIBUTION FACILITIES EXTENSIONS</u>

Prior to the start of construction of any facilities to provide an underground electric delivery service, the Applicant shall:

- Agree to all provisions for an underground electric connection prior to the start of any construction by the Company.

- Provide legal description of property, stake all easements and appropriate control points prior to the initiation of any work by the Company.

- Locate and clearly mark all other underground facilities currently existing on the Retail Customer's property.

- Make all arrangements deemed necessary or appropriate by the Company for payment of the Retail Customer's portion of costs

- Execute all contracts, deeds, easements, and other legal documents that the Company deems necessary or appropriate.

CUSTOMER ASSUMES THE RISK OF AND SHALL INDEMNIFY COMPANY AGAINST DAMAGES FOR INJURIES OR DEATH TO PERSONS OR LOSS TO CUSTOMER'S PROPERTY, OR TO THE PROPERTY OF COMPANY, WHEN OCCASIONED BY

ACTIVITIES OF CUSTOMER OR THIRD PARTIES ON CUSTOMER'S PREMISES, RESULTING FROM THE INSTALLATION, EXISTENCE, REPLACEMENT OR REPAIR OF COMPANY'S UNDERGROUND FACILITIES AS FURTHER PROVIDED IN THE TERMS OF "LIMITATION OF LIABILITY AND INDEMNIFICATION," SECTIONS 4.2 AND 5.2 OF THIS TARIFF. NOTWITHSTANDING ANY OF THE ABOVE, THE PROVISIONS REQUIRING A CUSTOMER TO INDEMNIFY, FULLY PROTECT, OR SAVE COMPANY HARMLESS APPLY TO A STATE AGENCY, AS THAT TERM IS DEFINED IN CHAPTER 2251 OF THE TEXAS GOVERNMENT CODE, ONLY TO THE EXTENT OTHERWISE AUTHORIZED BY LAW.

Overhead Facilities Extensions. Overhead facilities extensions for permanent service that do not exceed the requirements that the Company would normally provide to extend service and do not exceed the allowances stated herein, will be provided to Retail Customers within the Company's certificated area without requiring the Retail Customer to pay a CIAC to share in the cost. Any request requiring expenditures on the part of the Company in excess of the stated allowances or that require the Company to install facilities in excess of what the Company would normally install to provide service may require the Retail Customer to pay a CIAC.

Underground Facilities Extensions. Underground facilities extensions for permanent service that do not exceed the requirements that the Company would normally provide to extend service, and do not exceed the allowances stated herein, will be provided to Retail Customers within the Company's certificated area without requiring the Retail Customer to pay a CIAC. Any requests requiring expenditures on the part of the Company in excess of the stated allowances or that require the Company to install facilities in excess of what the Company would normally install to provide service may require the Retail Customer to pay a CIAC.

Area Development Facilities Extensions. Service facilities may also be extended at Company expense provided the facilities are required for increased reliability, service continuity, or development of the Company's distribution system. In conjunction with the installation of such facilities, the Company may extend service from these facilities to Retail Customers in accordance with the appropriate line extension plan.

FACILITIES EXTENSION ALLOWANCES AND FACTORS

The Company will consider the Standard Allowances, Facilities Extension Factors, and estimated costs to determine whether the Company's investment might produce a reasonable return for the investment in the facilities extension involved. If, in the Company's opinion, there are sufficient facts to indicate that the potential economic outlook for the proposed facilities warrants, those facts may support an allowance in addition to the standard allowance.

Facilities Extension Standard Allowances. End-use Retail Customers will be given credit toward the reasonable facilities construction cost based on the applicable Standard Allowance stated below. Facilities construction costs include labor, transportation, and standard materials, equipment, and appropriate overheads. In addition to construction, other costs incurred by the Company in providing an electric connection to a Retail Customer may also be billed to the Retail Customer. These include, but are not limited to, clearing of easements or rights-of-way, permit costs (railroad, Corps of Engineers, highway, etc.) and use of specialized equipment such as cranes, barges, etc. The calculation of construction costs incurred in the extension of electrical facilities will be applied in a uniform manner throughout the Company's certificated service territory.

Standard Allowance for a residential connection:	$1,718
Standard Allowance for a general service ≤ 10kW connection:	$789
Standard Allowance for general service > 10kW connection:	$337/kW
Standard Allowance for a primary voltage connection:	$215/kW

If in the Company's opinion, the estimated loads or lots served may not be realized, the Standard Allowance will be adjusted accordingly.

Allowance For Subdivisions With Front of Lot Delivery Service. To qualify for the Front of Lot Delivery Service Allowance, the electric delivery service must enter the front of the lot, the subdivision must contain more than 20 lots and the lot sizes must be smaller than one-half acre. Subdivisions located within cities that have ordinances requiring electric delivery service from the rear of the lots, or have restrictions/requirements that otherwise prevent electric service from being provided from the front of the lot, will not qualify for the allowance.

The Company will continue to use its current uniformly-applied policy to determine the appropriate level of allowances to be extended to the developer of the qualified subdivision. For each qualified subdivision, the Company will add $250 to each applicable Standard Allowance for a residential connection to be credited toward the cost of the electric infrastructure to be installed in the subdivision.

Facilities Extension Factors. Facilities Extension Factors considered by the Company in determining the Retail Customer's share in the cost of the extension include the following:

1. A comparison of the total estimated cost of the extension, excluding the standard allowances, to the estimated annual revenue for the type of service requested.

2. In the case of electrical facilities upgrades, only the cost of the added facilities that are required due to the Retail Customer's request are included in determining the cost to meet the Retail Customer's request. Those portions of the upgrade that will benefit the system but are not needed to meet the Retail Customer's request will not be included. When the Retail Customer's request requires the Company to make a system upgrade in a dually certificated area, the Retail Customer will be required to commit in writing that he will

reimburse the Retail Company for the undepreciated value of the upgrade in the event the Retail Customer elects to switch his electric connection provider to another utility.

3. If the expected revenue life of a facilities extension is not at least sixty (60) months, the facility will be deemed to be temporary service.

4. The possibility of serving additional Retail Customers from the proposed facilities within two (2) years.

SHARING OF CONSTRUCTION COSTS BETWEEN THE COMPANY AND THE RETAIL CUSTOMER

Construction cost issues, including sharing of construction costs between the Company and the Retail Customer, or sharing of costs among the Retail Customer and other Applicants, will be explained to the Retail Customer after assessment of necessary work to extend the facilities.

For permanent installations, and after consideration of all these factors and application of all appropriate allowances, any expenditure deemed to be excessive will require the Retail Customer to share in the cost of the extension through a CIAC to be paid prior to construction. CIACs are taxable and shall include an Income Tax Component of Contribution (ITCC) at the current applicable rates. This ITCC rate will be revised and published annually, and it is available on request. The amount of the CIAC will be the total cost of the facilities extension less all applicable allowances plus the impact for taxes. A Retail Customer requesting an installation which in the opinion of the Company may be of questionable permanence but not specifically temporary (such as, but not limited to, hunting or fishing camps) will pay a CIAC prior to construction. The CIAC for installations that the Company deems to be of questionable permanence will equal the total cost of the facilities extension. Should the Retail Customer default on the payment agreement, the full remaining balance of the CIAC will become due and will be billed to the Retail Customer immediately.

The CIAC is non-refundable and will be based on estimated costs and warranted allowances as stated above. Upon Customer request the Company will compare the estimated costs to the actual costs upon completion of the job. Any difference exceeding Ten Percent (10%) between estimated costs and actual costs will be refunded or billed as the case may be.

TEMPORARY SERVICE FACILITIES

All requests for electric delivery service which, in the opinion of the Company, will be utilized for less than 60 months will be considered to be temporary service unless they will continue to be utilized by a different Applicant. For temporary service facilities the Customer will be charged a CIAC for the total estimated construction and removal costs, less salvage and depreciation, if any, without allowances.

TRANSMISSION LINE EXTENSIONS (69KV AND ABOVE)

For retail loads that warrant transmission voltage service, as mutually determined by the Company and the Retail Customer, the Company will provide transmission voltage to one point of delivery via radial line, with one meter, at one of the Company's standard voltages. The Company will evaluate each new transmission service customer's request for connection to the transmission system to determine if a CIAC will be required. Additionally, unless the customer's CIAC is intended to fully fund the cost of interconnection, the Company may require additional contractual agreements and other means of security to ensure the costs for planning, licensing and constructing non-customer owned facilities are recoverable in the event the transmission service customer is unable to take transmission service.

If the Company is reimbursed more than $10,000,000 (including all applicable tax gross-up) by a Customer with respect to a transmission interconnection project, and more transmission customers are served by any or all of the facilities constructed pursuant to that reimbursement within a five-year period following the date in which any equipment is energized by the Company, then the initial Customer that reimbursed the Company shall be entitled to receive a prorated refund of the reimbursement for common facilities when the additional transmission customers execute an agreement for electric service within the five-year period described above. After payment is received from the additional transmission customer(s), a refund of reimbursement for common facilities to the initial Customer will be made on a pro-rata share of the amount initially paid by the initial Customer.

RETAIL CUSTOMER-OWNED SUBSTATION

Pursuant to the requirements of this section, a Retail Customer may design, construct, own and maintain the 138kV or below transmission voltage substation from which it takes service, including facilities that will become an integral part of the Company's transmission system network and ERCOT. The Retail Customer and the Company will execute an agreement establishing their respective responsibilities regarding the Retail Customer-owned substation consistent with the requirements of this section. Neither the Retail Customer nor the Company will unreasonably withhold its assent to such an agreement. The agreement will address, but not be limited to, the following elements: substation design criteria, telemetry specifications, protective relaying requirements, and outage, switching and clearance coordination procedures.

The Retail Customer understands and agrees that it is obligated to meet the Company's then-current design criteria when building a Retail Customer-owned substation unless the Company grants an exception as part of the review process described in this paragraph. The Retail Customer also understands and agrees that it may be required to modify the Retail Customer-owned substation in the future at the Retail Customer's expense if necessary to meet reliability needs or regulatory requirements. The Company will provide its then-current design criteria to the Retail Customer and notify the Retail Customer if modifications to the Retail Customer's substation are required to meet reliability or regulatory requirements. To ensure efficient coordination, the

Company and the Retail Customer will communicate during the process of the design and construction or modification of the Retail Customer-owned substation, and the Retail Customer agrees to submit its engineering documents to the Company for review and acceptance before equipment is ordered or construction begins. The Company agrees to promptly review and evaluate the Retail Customer's engineering documents and to not unreasonably withhold final acceptance of those documents. The Company's review of the Retail Customer's engineering documents shall not be construed as confirming, endorsing or providing a warranty as to the fitness, safety, durability or reliability of such facilities or the design thereof. However, the Company is responsible for ensuring that the design criteria it provides to the Retail Customer are adequate for the Retail-Customer owned substation to integrate safely and reliably with the Company's transmission system network and to meet ERCOT's requirements that are applicable to the Company's transmission system network.

The Retail Customer is responsible for all costs and liabilities related to the Retail Customer's design, construction, operation, maintenance, and ownership of the Retail Customer-owned substation, provided, however, that the Retail Customer is not responsible for liabilities arising from the Company's design criteria.

To ensure the safe and reliable operation of the Company's transmission system network and the Retail Customer's facilities, the Retail Customer and the Company will coordinate access, maintenance, and operations activities associated with the Retail Customer-owned substation as required.

The Retail Customer further understands and agrees that it is solely responsible for ensuring compliance with the applicable North American Electric Reliability Corporation (NERC) standards for equipment owned by the Retail Customer inside the Retail Customer-owned substation, except: (i) the Company agrees to provide reports necessary for such compliance as outlined in the agreement; and (ii) to the extent that the Company has otherwise agreed in writing to assume responsibility. The Retail Customer shall comply with any applicable requirements of ERCOT and any governmental authority with respect to its ownership and operation of transmission facilities. Upon request, the Retail Customer shall provide copies to the Company of any reports that the Retail Customer is required to file with respect to the Retail Customer-owned substation with entities such as NERC, the Texas Reliability Entity, and ERCOT.

This section does not affect the terms of an agreement between a Retail Customer and the Company as those terms existed as of March 12, 2021 concerning customer-owned substations.

PUC DOCKET NO. 56211

APPLICATION OF CENTERPOINT	§	PUBLIC UTILITY COMMISSION
ENERGY HOUSTON ELECTRIC, LLC	§	
FOR AUTHORITY TO CHANGE RATES	§	OF TEXAS

DIRECT TESTIMONY

OF

LYNNAE K. WILSON

ON BEHALF OF

CENTERPOINT ENERGY HOUSTON ELECTRIC, LLC

MARCH 2024

Houston complex alone ranked first in the United States in foreign waterborne tonnage, first in total foreign and domestic waterborne tonnage, and second in terms of total foreign cargo value. It is the largest port in Texas and largest Gulf Coast container port, handling 73% of United States Gulf Coast container traffic, up from 69% in 2018. Similarly, the Texas Medical Center is the largest medical complex in the world, with an estimated 8 million patients per year visiting a campus of over 50 million square feet. Investments necessary to connect large scale commercial operations to the Company's system, such as those described in the testimony of Ms. Harris, serve to ensure the continued economic success of Houston, the state of Texas, and the country. That investment has been a necessary component of the area's economic growth and driver of the Company's capital investment plan.

Q. HOW HAS THE INCREASE IN INTERCONNECTION REQUESTS BY NEW GENERATION RESOURCES IMPACTED THE COMPANY'S NEED TO INVEST IN ITS SYSTEM?

A. The increase in interconnection requests by new generation resources has been a significant driver for investing in the transmission system. From 2019 through the end of 2023, the Company has interconnected 25 new generation resources with a planned capacity of approximately 6,500 MW. Ten generation resources were interconnected at existing switching stations. The remaining fifteen generation resources required the construction of new 138 kV or 345 kV switching stations as further described by Company witness Mr. Mercado.

Q. WHAT FACTORS HAVE IMPACTED THE COMPANY'S ONGOING FINANCING NEEDS?

A. As discussed in the direct testimony of Company witnesses Jacqueline M. Richert and Jennifer K. Story, the Inflation Reduction Act of 2022 ("IRA") imposes a new Corporate Alternative Minimum Tax ("CAMT") and the Company expects that CNP will be subject to the 15% minimum tax payment in 2024. The cash outlay associated with the CAMT will likely impair CenterPoint Houston's credit metrics. In particular, reduced cash from operations and earnings before interest, taxes, depreciation, and amortization metrics have the strong potential to cause rating agencies to issue lower credit ratings for CenterPoint Houston absent a constructive response from the Commission that includes an increase in the Company's authorized equity ratio and ROE.

To counter this negative impact and facilitate CenterPoint Houston's ability to respond to economic growth, the Company is requesting that its actual capital structure of 44.9% equity and 55.1% long-term debt and an ROE of 10.4% be used to set rates. Ms. Richert explains that a 44.9% equity ratio will help CenterPoint Houston move its current issuer rating to A3. Company witness Ann Bulkley explains that an ROE of 10.6% is supported by her analysis, but the Company has decided to propose an ROE of 10.4% which as explained by Company witnesses Ms. Richert and Jason M. Ryan will continue to allow the Company to attract capital and fund the necessary system investment required to safely and reliably respond to system growth, and efficiently and innovatively meet the needs of its customers.

Q. PLEASE DESCRIBE CENTERPOINT HOUSTON'S FILING IN THIS CASE.

A. The Company's filing has been prepared consistent with the requirements of PURA and the Commission's Substantive and Procedural Rules, including the Transmission and Distribution Investor-Owned Utilities Rate Filing Package ("RFP") for Cost-of-Service Determination, adopted by the Commission in Docket No. 49199. CenterPoint Houston's filing is based on a test year ended December 31, 2023. In addition to the Company's Application and Statement of Intent ("Application"), the components of the filing include the sworn direct testimony of 29 internal and external witnesses, direct testimony workpapers, revised tariffs, required schedules, and schedule workpapers. The filing reflects the considerable efforts of many Company employees and additional external resources, and it provides an accurate and transparent view of our business. The witnesses submitting direct testimony in support of CenterPoint Houston's Application and the topics they address are described in the table attached to my testimony as Exhibit LKW-2.

Q. WHAT IS THE TOTAL COST CENTERPOINT HOUSTON INCURS TO PROVIDE SERVICE TO ITS CUSTOMERS?

A. As described and supported in the Company's RFP, CenterPoint Houston's total cost of service based on a Test Year ended December 31, 2023, as adjusted for known and measurable changes, is approximately $2.4 billion, excluding costs related to wholesale transmission from others This includes a proposed ROE of 10.4%, a capital structure of 55.1% debt and 44.9% equity, and a proposed overall weighted average cost of capital of 7.03% on a rate base of approximately $12.1 billion. As demonstrated by Company witness Ms. Colvin's testimony, the