ERCOT Permian Basin Reliability Plan Study

Final

July 2024

Document Revisions

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07/25/2024	1.0	Final Report	Ying Li, Scott Zuloaga
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Executive Summary

In 2023, the Texas Legislature enacted House Bill (HB) 5066, which, among other things, required the Public Utility Commission of Texas (PUCT) to direct ERCOT to develop a reliability plan for the Permian Basin region.[1] As required by HB 5066, ERCOT's reliability plan for the Permian Basin must:

- Address extending transmission service to areas where mineral resources have been found;
- Address increasing available capacity to meet forecasted load; and
- Provide available infrastructure to reduce interconnection times in areas without access to transmission service.[2]

On December 14, 2023, the PUCT issued an order in Project No. 55718 directing ERCOT to develop a reliability plan for the Permian Basin region.[3] The order established a process and timeline for developing the plan and required ERCOT to submit the plan to the PUCT "not later than July 2024" ahead of the PUCT's anticipated approval of the plan in September 2024.[4]

ERCOT began development of the Permian Basin Reliability Plan in January 2024. Over the ensuing six months, ERCOT conducted extensive engineering analysis and obtained substantial review and input from Transmission and Distribution Service Providers (TDSPs) and other stakeholders in the ERCOT region through the Regional Planning Group (RPG). As a culmination of these efforts, ERCOT has produced this Reliability Plan to identify the transmission needs of the Permian Basin region and the transmission upgrades required to meet the forecasted electric demand in the region.

Load Growth in the Permian Basin Region

Increased oil and gas development in the Permian Basin has resulted in a marked increase in transmission needs in recent years. ERCOT's historical data show that demand in the Far West Weather Zone—which includes a significant portion of the Permian Basin—has experienced an average annual peak demand growth rate of approximately 11% for the last decade due to increased development activity associated with the oil and gas industry. This growth rate is the highest of any weather zone in the ERCOT region. ERCOT has undertaken several initiatives to address these unique needs. In 2019, ERCOT completed the Delaware Basin Load Integration Study;[5] in 2021, it completed the Permian Basin Load Interconnection Study.[6] Based on the transmission needs identified in these and other ERCOT studies, ERCOT has endorsed about $5.7 billion worth of transmission projects in the Permian Basin region since 2014.

[1] Tex. H.B. 5066, 88th Leg., R.S. (2023), § 3 (creating new Texas Utilities Code section 39.167).
[2] Public Utility Regulatory Act (PURA) § 39.167(b).
[3] *Reliability Plan for the Permian Basin Under PURA § 39.167*, Project No. 55718, Order Directing ERCOT to Develop a Reliability Plan for the Permian Basin Region (Dec. 14, 2023) ("Permian Order").
[4] *Id.* at 2, 3.
[5] ERCOT Delaware Basin Load Integration Study Report: https://www.ercot.com/gridinfo/planning
[6] ERCOT Permian Basin Load Interconnection Study Report: https://www.ercot.com/gridinfo/planning

While the Permian Basin has already experienced unprecedented load growth, data provided by TDSPs—and relied upon by ERCOT for the purposes of this study, as required by statute[7]—indicates that the electric demand driven by oil and gas development in the Permian Basin is continuing to grow over the next 15 years. Specifically, a 2022 load forecast developed by S&P Global and submitted to ERCOT by Oncor Electric Delivery Company LLC (Oncor) projected growth in peak oil-and-gas-related demand of 11,964 MW in 2030 and 14,705 MW in 2039, reflecting an expectation of a material expansion of oil and gas development in the Permian Basin region.

However, in addition to rapid growth in oil and natural gas demand, TDSPs have also provided demand projections indicating an exponential increase in the number of non-oil and gas loads in the Permian Basin region. The majority of the forecasted demand associated with these non-oil and gas loads primarily consists of demand related to cryptocurrency mining operations, data centers, and hydrogen electrolysis facilities. The total additional non-oil-and-gas demand in the Permian Basin region for 2030 (and 2038) based on information provided by the TDSPs is 11,695 MW. Summing the S&P Global forecast with the TDSP-provided load forecasts, the total demand in the Permian Basin region ERCOT has modeled in its studies for 2030 is 23,659 MW, and the total demand modeled for 2038 is 26,400 MW.

ERCOT also anticipates significant load growth outside the Permian Basin region. TDSP load forecasts for the 2024 Regional Transmission Plan (RTP) have identified approximately 59,400 MW of additional demand across the ERCOT System that will need to be served by 2030.[8] Most of this sharp increase in demand is attributable to large loads such as load greater than 75 MW at a single site.

Assessment of Transmission Needs

While ERCOT has evaluated transmission needs as far out as 2038 consistent with the projected increase in load shown in the S&P Global forecast, ERCOT has also chosen to identify transmission needs in 2030, consistent with ERCOT's traditional practice of evaluating needs using a maximum time horizon of six years. Even so, the S&P Global forecast suggests that almost 90% of the 2038 load will materialize by 2030. Because of this two-phased assessment, the transmission needs identified in 2030 are naturally a subset of those required for 2038.

In identifying these transmission needs, ERCOT divided the proposed upgrades into two categories: local transmission upgrades and import paths. Local transmission upgrades are transmission projects that are needed to interconnect and serve the projected load in the Permian Basin region assuming that power can be imported into the region. Import paths are those transmission projects needed to transfer power from other regions into the Permian Basin region to serve the projected demand. ERCOT categorized the projects this way for two reasons: First, ERCOT's identification of local needs explicitly fulfills the PUCT's directive to "address extending transmission service to areas where

[7] PURA § 39.166(a)(1) provides that the "existing and forecasted load" used in identifying transmission needs as part of a reliability plan study must be the load that is "reasonably determined by the certificated transmission service provider."
[8] https://www.ercot.com/files/docs/2024/04/08/2024_RTP_Load_Review_Update_April_2024_RPG.pdf.

mineral resources have been found" and to "provide available infrastructure to reduce interconnection times in areas without access to transmission service" while its separate identification of import paths explicitly meets its obligation to "address increasing available capacity to meet forecasted load," consistent with HB 5066.[9] Second, ERCOT's separate identification of import paths is appropriate because ERCOT has identified several materially different options for these import paths. Specifically, ERCOT has determined that the significant increase in forecasted load justifies consideration of the use of extra high voltage (EHV) transmission infrastructure—operated at 500-kV or 765-kV—for the import path options, given that EHV facilities are generally known to provide benefits such as reducing losses for long-distance power transportation, increasing short circuit strength, and improving voltage stability compared with transmission facilities operating at 345-kV, which is the maximum voltage currently used on the ERCOT System. Thus, for local upgrades, ERCOT considered only 345-kV and lower facilities while for the import paths, ERCOT evaluated three mutually exclusive options: 345-kV, 500-kV, and 765-kV.

For the purposes of this study, ERCOT's analysis of the EHV (500-kV and 765-kV) import path options was limited to 2038 and did not consider 2030. ERCOT will be evaluating the EHV needs for 2030 as part of its 2024 RTP, which ERCOT expects to complete in December. Importantly, ERCOT's assessment of the EHV options in the 2024 RTP will provide a more complete picture of the optimal use of EHV because it will evaluate the needs of the entire ERCOT System and not just the Permian Basin region. ERCOT expects that the EHV facilities identified in this Permian Basin Reliability Plan could differ from the EHV facilities that would serve the Permian Basin region identified in the 2024 RTP solely on account of this more comprehensive scope. For this reason, if the PUCT intends to give any consideration to 500-kV or 765-kV EHV infrastructure to address transmission needs in the Permian Basin, it may wish to defer a final decision on the appropriate import path option for the Permian Basin region until ERCOT has finalized the EHV assessment in the 2024 RTP. If necessary, ERCOT can evaluate incremental 2038 500-kV or 765-kV EHV needs associated with Permian Basin region load once the 2024 RTP is complete.

The following is a summary of ERCOT's need findings in this study:

Common Local Transmission Upgrades

ERCOT's analysis concluded that the local upgrades needed to serve the Permian Basin region load in 2030 or 2038 do not vary significantly on which import path option is selected. Thus, irrespective of whether the PUCT defers its decision on the import path option, the PUCT may wish to consider proceeding with approving the common set of local transmission upgrades that would be needed irrespective of the forecast horizon or the import path chosen, as these facilities will be needed in any case. Below is a summary of the common transmission upgrades:

- Add approximately 174 miles of new 345-kV double-circuit transmission lines
- Upgrade approximately 43 miles of existing 345-kV transmission lines and add second circuits

[9] Permian Order at 1.

- Upgrade approximately 98 miles of existing 345-kV double-circuit transmission lines
- Add 8 new 345-kV/138-kV substations with 17 new 345-kV/138-kV transformers
- Add approximately 186 miles of new 138-kV transmission lines
- Upgrade approximately 221 miles of existing 138-kV transmission lines
- Convert approximately 230 miles of existing 69-kV transmission lines to 138-kV
- Add approximately 3,600 MVAr worth of reactive power devices

The total cost estimate for the common local transmission upgrades needed in 2030 and 2038 is approximately $4.02 billion. The details of common transmission upgrades needed in 2030 and 2038 under all import path options are summarized in the Section 7 Table 7.1.

Import Path Options and Associated Incremental Local Transmission Upgrades

As noted above, for 2030, ERCOT considered only a 345-kV import path option. For 2038, ERCOT evaluated a 345-kV option as well as 500-kV and 765-kV EHV import path options. The two EHV options will be part of a systemwide EHV study of 2030 needs to be completed later in 2024. If the 500-kV or 765-kV import options are selected as the best option for 2038, the 345-kV import paths identified as needed for 2030 may be substituted with alternative 500-kV or 765-kV lines that will be identified in ERCOT's forthcoming EHV study. Below is the summary of the import paths needed in 2030 and 2038.

➢ **2030**

345-kV Option: For 2030, two new double-circuit 345-kV import paths would be needed to serve Permian Basin load:

- One import path from North/Central Texas and one from South Texas
- Total length: Approximately 847 miles
- Additional new dynamic reactive devices will be required
- The following incremental local transmission upgrades are needed to meet the projected demand in 2030 for 345-kV option:
    - Add approximately 71 miles of new 345-kV transmission line
    - Upgrade approximately 57 miles of existing 345-kV transmission lines and add second circuits
    - Upgrade approximately 23 miles of existing 138-kV transmission line

The details of 345-kV option needed in 2030 are summarized in the Section 7 Table 7.2.

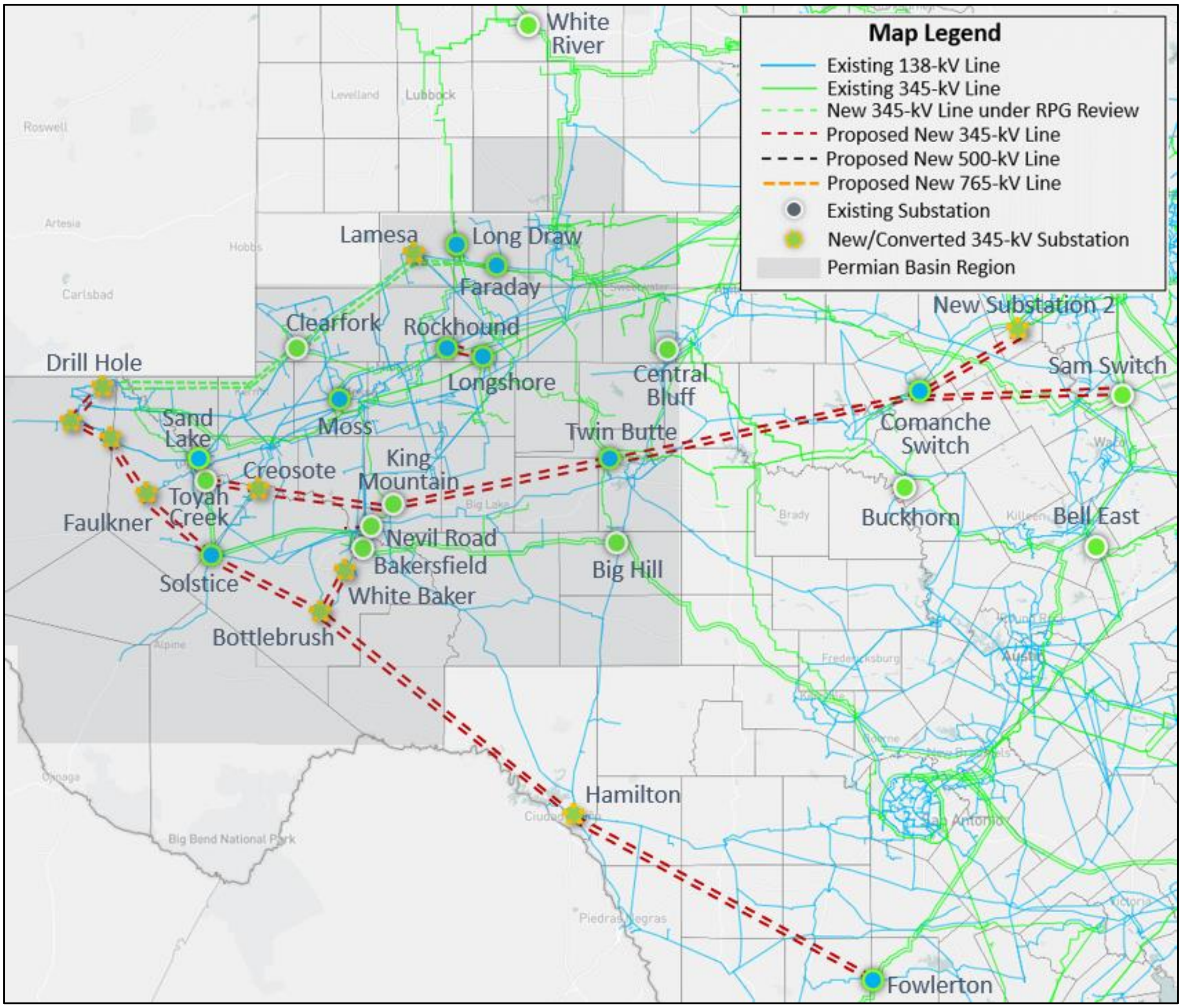

Figure E.1: 345-kV Transmission Upgrades Needed in 2030

➢ 2038

345-kV Option: Four new double-circuit 345-kV import paths (two double-circuit 345-kV paths identified for 2030 + two additional double-circuit 345-kV paths for 2038) plus a short path from the Panhandle would be required to serve the 2038 Permian Basin load:

- Three import paths from Central Texas and one import path from South Texas
- Total length: Approximately 1,676 miles
- Additional new dynamic reactive devices will be required
- The following incremental local transmission upgrades are needed to meet the projected demand in 2038 for 345-kV option:
  - Add approximately 82 miles of new 345-kV transmission lines
  - Add 2 new 345-kV/138-kV substations with 5 new 345-kV/138-kV transformers

- Upgrade approximately 57 miles of existing 345-kV transmission lines and add second circuits
- Upgrade approximately 25 miles of existing 138-kV transmission line

The details of 345-kV option needed in 2038 are summarized in the Section 7 Table 7.3.

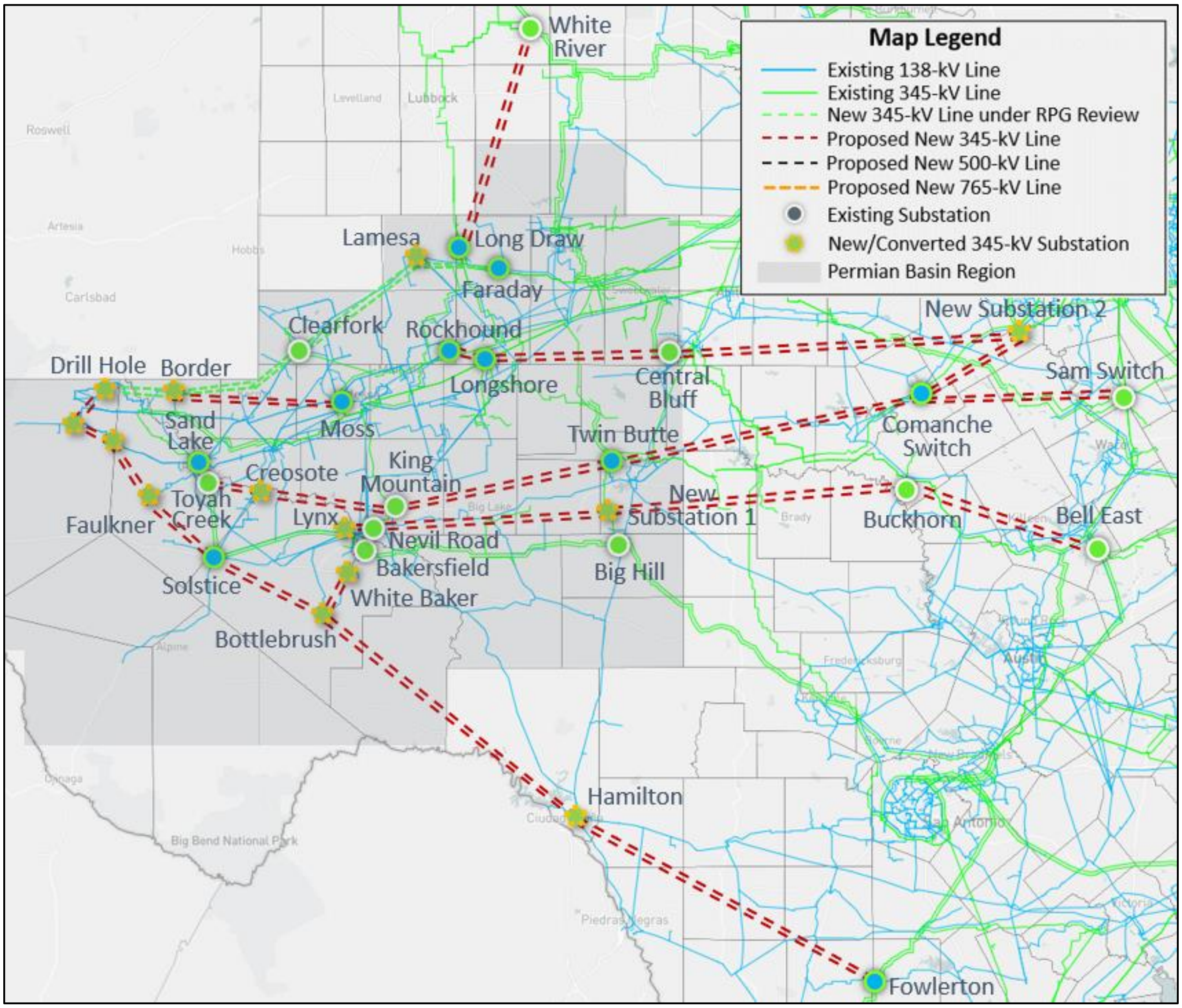

Figure E.2: 345-kV Transmission Upgrades Needed in 2038 (Includes Import Paths Needed in 2030)

500-kV Option: Three new double-circuit 500-kV import paths plus a 345-kV short path from the Panhandle would be required to serve the 2038 Permian Basin load:

- Total length: approximately 1,255 miles of 500-kV line and approximately 115 miles of new 345-kV double-circuit line
- Additional new dynamic reactive devices will be required; however, the amount of new dynamic reactive devices will be lower than would be required under the 345-kV option resulting in approximate savings of $240 million
- The following incremental local transmission upgrades are needed to meet the projected demand in 2038 for 500-kV option:
  - Add approximately 74 miles of new 345-kV transmission lines
  - Add 2 new 345-kV/138-kV substations with 5 new 345-kV/138-kV transformers
  - Upgrade approximately 53 miles of existing 345-kV transmission lines

The details of 500-kV option needed in 2038 are summarized in the Section 7 Table 7.4.

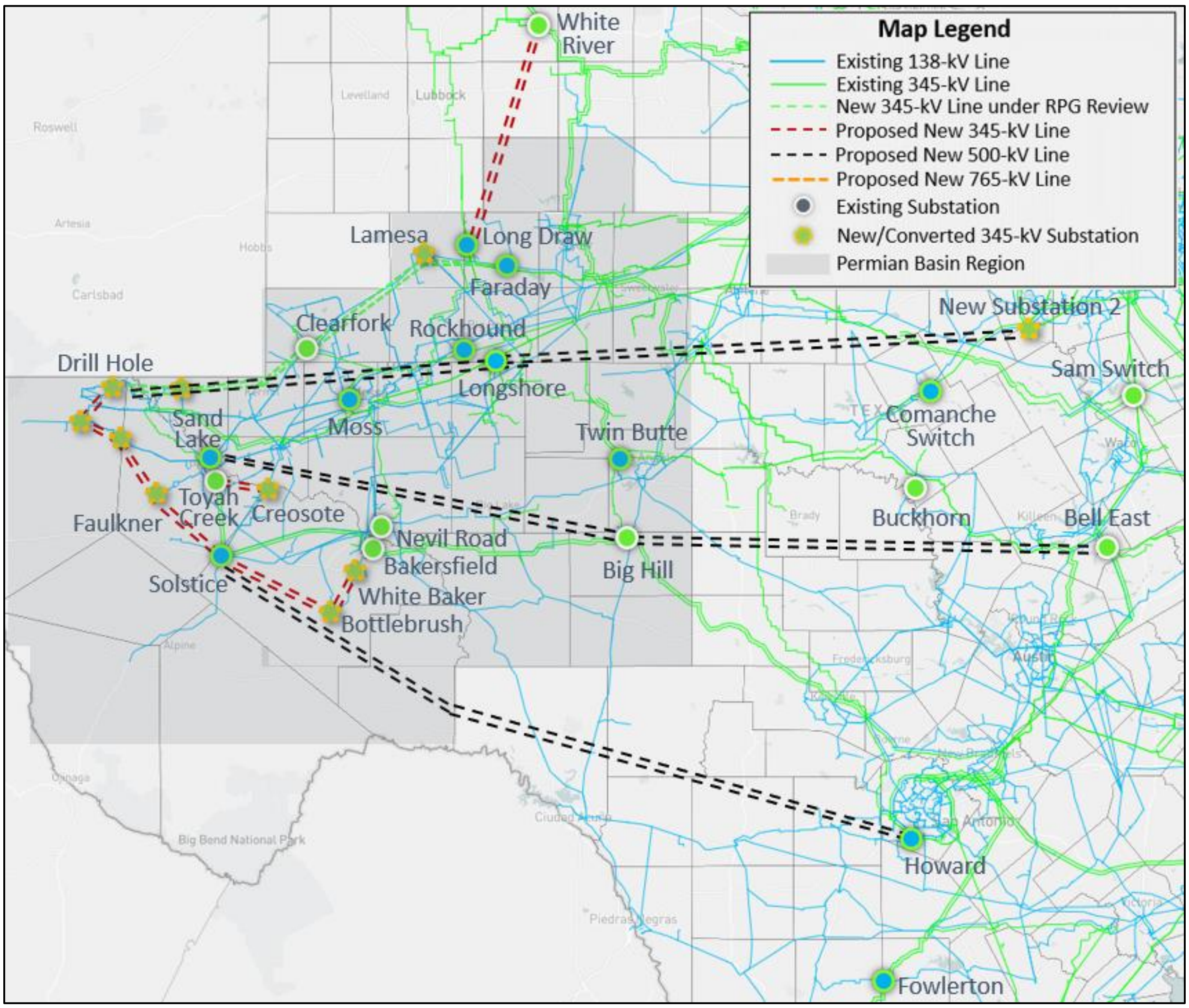

Figure E.3: 500-kV Import Path Option for 2038

765-kV Option: Three new single-circuit 765-kV import paths will be required to serve the 2038 Permian Basin load:

- Total length: approximately 1,255 miles
- Additional new dynamic reactive devices will be required; however, the amount of new dynamic reactive devices will be lower than would be required under the 345-kV option resulting in approximate savings of $240 million
- The following incremental local transmission upgrades are needed to meet the projected demand in 2038 for 765-kV option:
  - Add approximately 74 miles of new 345-kV transmission lines
  - Add 2 new 345-kV/138-kV substations with 5 new 345-kV/138-kV transformers
  - Upgrade approximately 53 miles of existing 345-kV transmission lines

The details of 765-kV option needed in 2038 are summarized in the Section 7 Table 7.5.

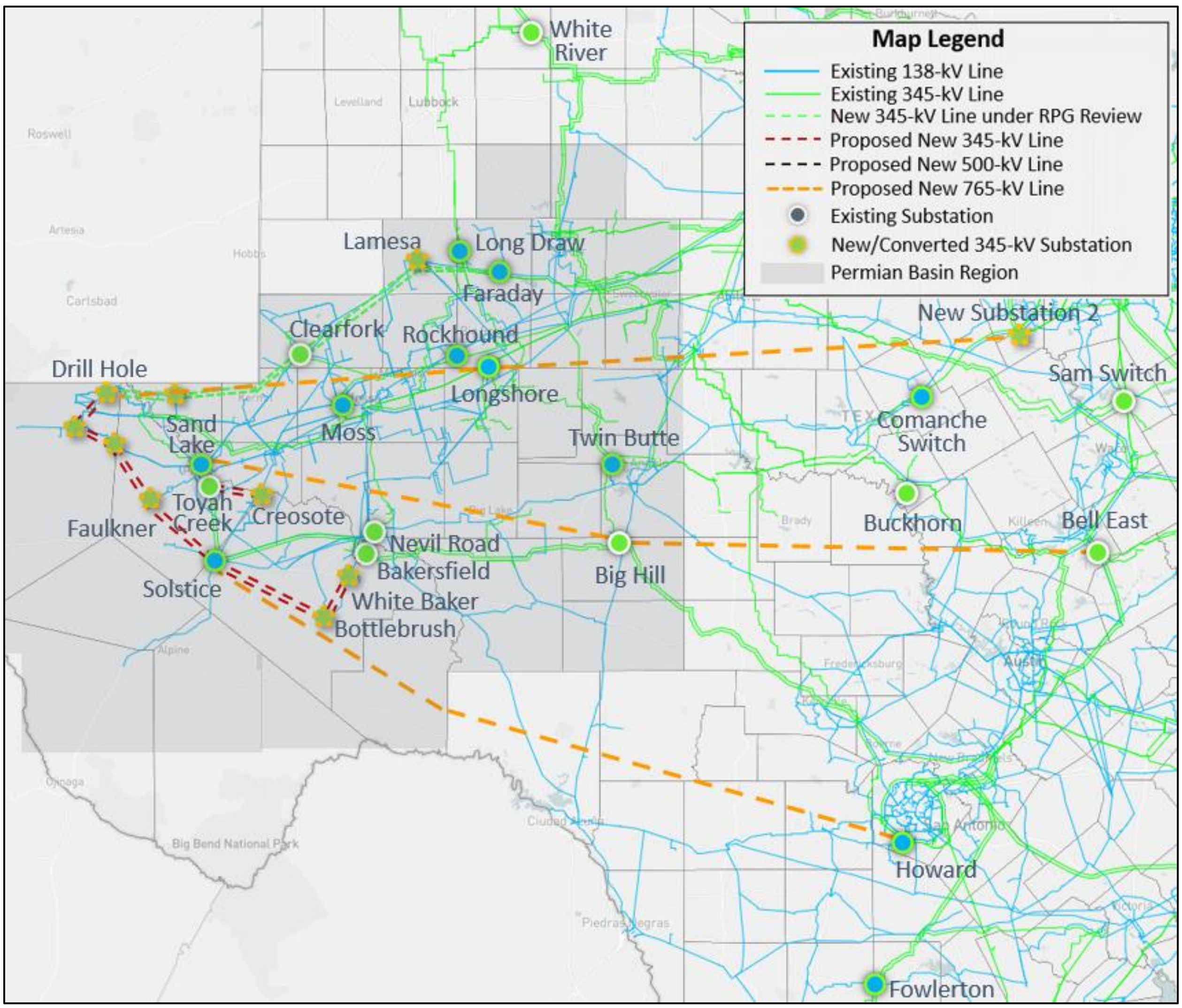

Figure E.4: 765-kV Import Path Option for 2038

Table E.1 compares the 345-kV import path option and EHV (500-kV and 765-kV) options.

Table E.1: Import Paths Comparison of 345-kV and EHV (500-kV and 765-kV) Options in 2038

	345-kV	500-kV	765-kV
Meets ERCOT and NERC Reliability Criteria	Yes	Yes	Yes
Incremental Transfer Capability* (MW)	1,340	1,712	2,105
Improves Operational Flexibility	Yes	Yes	Yes
Transmission Losses under System Peak Condition	3.0%	2.8%	2.7%
Number of Import Paths Required	5	4	3
New ROW** Required for Import Paths (miles)	1,676	1,370	1,255
Average Transmission Line Cost*** ($Million/mile)	4.04	6.86	6.10
Total Cost Estimate ($Billion)	12.95	15.32	13.77

* Incremental transfer capability under N-1 contingency conditions.

** A routing adder of 20% to the straight distance between two end points was assumed.

*** For 345-kV import path option, the average cost based on the TSPs cost estimates for 345-kV import paths was used. MISO 2024 Transmission Cost Estimation Guide was referenced for the EHV options (500-kV or 765-kV).

Costs

For the transmission upgrades at 345-kV and below, estimates of the capital cost of each transmission upgrade were provided by the Transmission Service Provider (TSP) responsible for each upgrade. If multiple TSPs provided the cost estimates for the same transmission upgrade, ERCOT used the highest cost estimate to calculate the total project cost estimates. For the 500-kV and 765-kV upgrade options, ERCOT used publicly available cost information to calculate the total project cost estimates. Tables E.2 and E.3 summarize the cost estimates for common local upgrades, import paths, incremental local upgrades associated with each import path option and total upgrades for 2030 and 2038.

Table E.2: Summary of the Cost Estimates ($Billion) for 2030*

	2030
Common Local Upgrades	4.02
Import Paths	3.99
Incremental Local Upgrades	1.03
Total	**9.04**

* 2030 Import paths and Incremental Local Upgrades are subset of 2038 345-kV Option

Table E.3: Summary of the Cost Estimates ($Billion) for 2038

	2038		
	345-kV Option	500-kV Option	765-KV Option
Common Local Upgrades	4.02	4.02	4.02
Import Paths	7.69	10.61	9.06
Incremental Local Upgrades	1.23	0.69	0.69
Total	**12.95**	**15.32**	**13.77**

In summary, ERCOT estimates that the costs of the transmission upgrades needed to serve the forecasted Permian Basin load in 2038 range from $12.95 billion to $15.32 billion, depending on the selected option.

With respect to these cost estimates, ERCOT notes the following:

- The cost estimates for the local transmission upgrades include 345-kV and 138-kV transmission upgrades, 69-kV transmission conversions, and placeholder reactive power devices.
- The difference in the cost estimates for the 2038 incremental local transmission upgrades under the 345-kV and EHV options is due to a small number of transmission upgrades not needed in the EHV options.
- The cost estimates of the import path options include transmission upgrades and associated dynamic reactive devices.

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1 Introduction

Over the past ten years, the Far West Weather Zone, which includes significant portion of the Permian Basin, has experienced an average annual peak demand growth rate of approximately 11% driven by the significant growth in oil and natural gas industry demand. Due to the short-term planning horizons of the oil and gas industry resulting in lack of long-term load commitments, ensuring that necessary transmission improvements are in place in time to accommodate the rapid oil and gas development continues to be a challenge. As part of the efforts to address this challenge, significant amounts of transmission upgrades have been approved and completed in the Permian Basin region in recent years.

In addition, ERCOT with significant support from the relevant TDSPs performed two special studies, the Delaware Basin Load Integration Study in 2019 and the Permian Basin Load Interconnection Study in 2021, to accommodate the significant and rapid load growth and to address the transmission needs in the Permian Basin region. ERCOT completed the Delaware Basin Load Integration Study in December 2019 and developed a roadmap involving new 345-kV lines to improve load serving capability to import power into the Delaware Basin area. The roadmap includes five stages of new 345-kV lines. The Stage 1 upgrade was endorsed in June 2021 and has been constructed. The Stage 2 upgrade was endorsed by the ERCOT Board of Directors in August 2022. The Stage 3, Stage 4, and Stage 5 upgrades are currently under ERCOT independent review. ERCOT also completed the Permian Basin Load Interconnection Study in December 2021 and proposed a set of preferred transmission upgrades to connect and reliably serve forecasted load in Permian Basin region, total approximately $1.5 billion.

The TDSPs serving the load in the Permian Basin region have also made significant efforts to better understand the underlying dynamics of oil and gas development throughout the region. This effort led to the completion of two customer demand studies by IHS Markit in 2020[10] and S&P Global in 2022[11], which provided an in-depth analysis of the oil and gas industry and provided more granular and detailed electricity demand forecast in the Permian Basin region through 2040. The S&P Global Permian Basin load forecast is 11,964 MW in 2030 and 14,705 MW in 2038.

In addition to the rapid growth in the oil and gas demand in the Permian Basin region, significant amounts of large loads are seeking interconnection in the area as well. The additional non-oil and gas load in the Permian Basin region included in this study is 11,695 MW for both 2030 and 2038. The total amount of additional non-oil and gas load is almost the same as the oil and gas load.

ERCOT with significant support from the relevant TDSPs completed this Permian Basin Reliability Plan Study in June 2024 utilizing the demand forecast from the S&P Global study as well as additional non-oil and gas load in the Permian Basin region to identify the reliability needs and developed a set

[10] https://www.ercot.com/files/docs/2020/11/27/27706_ERCOT_Letter_to_Commissioners_-_Follow-up_Status_Update_on_Permian....pdf
[11] https://www.ercot.com/files/docs/2023/03/17/Presentation%20to%20ERCOT%20planning.pdf

of transmission upgrades to connect and reliably serve the forecasted loads in the Permian Basin region. This report describes the study assumptions, methodology and the results of ERCOT's assessment.

2 Study Assumptions and Methodology

ERCOT performed studies under various system conditions to identify the reliability issues and to evaluate and determine the appropriate transmission upgrades to address those reliability violations. This section describes the study assumptions and criteria used to conduct this study.

2.1 Study Assumptions for Reliability Analysis

The Permian Basin region, including the Delaware Basin, Midland Basin, and Central Basin Platforms, spans most of the counties in the Far West Weather Zone plus ten adjacent counties in the West Weather Zone and two counties in the North Weather Zone. Figure 2.1 shows the counties in the Permian Basin region which were included in this study.

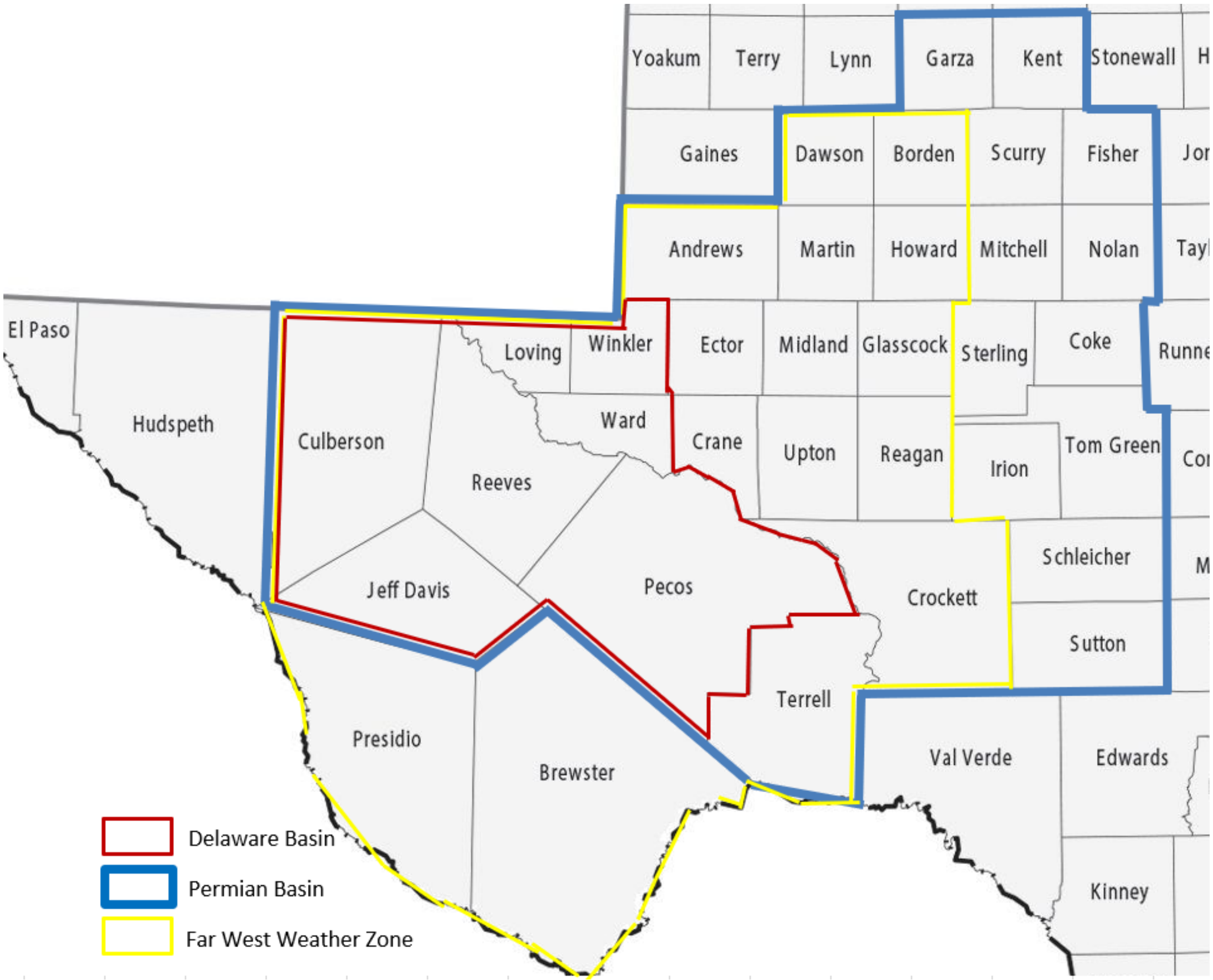

Figure 2.1: Counties in the Permian Basin Region

2.1.1 Steady-State Study Base Case

The 2023 RTP case, published on the Market Information System (MIS) in October 2023, was used as the starting case in this study. The steady-state study base cases for year 2030 and 2038 were constructed by updating the transmission, generation, and loads of the following 2029 Summer Peak Load case for the West and Far West (WFW) Weather Zones:

- Case: 22SSWG_2029_SUM_WFW_10252023[12]

[12] 2023 Regional Transmission Plan Postings: https://mis.ercot.com/secure/data-products/group-reports/transmission-service-providers?id=PG7-148-M

2.1.2 Transmission Topology

Transmission projects within the study area with In-Service Dates (ISDs) by the respective years were added to the study base cases. The ERCOT Transmission Project Information and Tracking (TPIT)[13] report posted in October 2023 was used as reference. The added TPIT projects are listed in Table 2.1.

Table 2.1: List of Transmission Projects Added to Study Base Cases

TPIT No	Project Name	Tier	Project ISD	TSP	From County
71944	LCRATSC_SingleTree_Substation_Addition	Tier 4	Oct-23	LCRATSC	Crockett
73476	TNMP_KERMIT_RECONDUCTOR	Tier 4	Jan-24	TNMP	Pecos
70964	WETT 345-kV Volta witch	Tier 3	Jan-24	WETT	Howard
76151	Gas Pad Tap: Replace CTVT	Tier 4	Apr-24	AEP TCC	Reeves
72863	Delaware River 138-kV Switch	Tier 4	May-24	ONCOR	Culberson
73434	Shaw 138-kV POD	Tier 4	May-24	ONCOR	Reagan
76212	Model Coachwhip Sub	Tier 4	May-24	TNMP	Ward
71960	Upgrade Grady – Expanse 138-kV Line	Tier 4	Dec-24	ONCOR	Martin
71989	Big Spring West – Stanton East 138-kV Line	Tier 4	Dec-24	ONCOR	Martin
71993	Tributary – Vincent 138-kV Line Section	Tier 3	Dec-24	ONCOR	Howard
72004	Cat Claw 138-kV Dynamic Reactive Device (formerly Midkiff)	Tier 3	Dec-24	ONCOR	Upton
73043	Peck – Driver 138-kV Line	Tier 2	Dec-24	ONCOR	Glasscock
76686	Add Hog Mountain 138-kV POD	Tier 4	Dec-24	ONCOR	Glasscock
76690	Add Atchison POD	Tier 4	Dec-24	ONCOR	Loving
76719	Establish 138-kV Switch	Tier 4	Dec-24	ONCOR	Loving
76174	Origin 138-kV Interconnection	Tier 4	Jun-25	AEP TNC	Reeves
76712	Rebuild existing 138-kV Line	Tier 4	Dec-25	ONCOR	Mitchell
76232	Reconductor Mivida-Coachwhip-Fishhook 2045 ACCC	Tier 4	May-26	TNMP	Ward
76291	Upgraded Cedarvale – BoneSpringsTap–Fishhook	Tier 4	May-26	TNMP	Ward
76293	Upgraded Cedvale-MiDiva138-kV	Tier 4	May-26	TNMP	Ward
76348	Reconductor Foxtail-PIGCreek-1926ACSS-138-kV	Tier 4	May-26	TNMP	Pecos
72884	Gonzales: Build 69-kV STATCOM	Tier 4	May-24	ETT	Presidio
66532	Grey Well Draw – Pronghorn 138-kV Line Rebuild	Tier 4	Dec-23	ONCOR	Midland
23RPG013	Silverleaf and Cowpen 345/138-kV Stations Project	Tier 1	Jun-27	TNMP	Reeves
23RPG026	Synchronous Condensers Project	Tier 1	Oct-27	WETT	Borden
23RPG027	Bakersfield Dynamic Reactive Substation Upgrade	Tier 1	May-27	LCRA	Pecos
23RPG029	West Texas Synchronous Condenser Project	Tier 1	May-27	ONCOR	Ector
23RPG023	Pecos County Transmission Improvement Project	Tier 1	Aug-26	TNMP	Pecos

[13] TPIT Report: https://www.ercot.com/gridinfo/planning

TPIT No	Project Name	Tier	Project ISD	TSP	From County
24RPG002	Rockhound 345/138-kV Switch and Grey Well Draw to Buffalo 2nd 138-kV Circuit Project	Tier 3	Dec-24	ONCOR	Martin
23RPG034	West Texas 345-kV Infrastructure Rebuild Project	Tier 1	Summer 2028	ONCOR	Midland
24RPG006	Prairieland 345/138-kV Switch and Prairieland Switch to Quartz Sand Switch/Hog Mountain Pod 138-kV Line Project	Tier 3	Summer 2025	ONCOR	Glasscock

In addition to adding the TPIT transmission projects in Table 2.1, the major 345-kV transmission upgrades identified in the 2019 ERCOT Delaware Basin Load Integration Study which have not been RPG approved were also included in this study:

- Updated Stage 3 upgrade: Add a new Riverton – Drill Hole 345-kV double-circuit line
- Stage 4 upgrade: Convert the existing Riverton – Sand Lake 138-kV line to 345-kV and add a new Riverton – Sand Lake 138-kV line
- Updated Stage 5 upgrade: Add new Faraday – Lamesa – Clearfork – Drill Hole 345-kV double-circuit line

In the 2019 ERCOT Delaware Basin Load Integration Study, the Stage 3 upgrade recommended a new Riverton – Owl Hills 345-kV single-circuit line, and the Stage 5 upgrade recommended a new Faraday – Lamesa – Clearfork – Riverton 345-kV double-circuit line. Due to the significant load increase in the oil and gas industry in the Delaware Basin area and the physical limitations for expansion of the existing Owl Hills 138-kV substation, the updated Stage 3 upgrade includes a new Riverton – Drill Holes 345-kV double-circuit line and the updated Stage 5 upgrade includes a new Faraday – Lamesa – Clearfork – Drill Hole 345-kV double-circuit line. The Drill Hole substation is approximately 3 miles southwest of the Owl Hills substation. The updated Stage 3 upgrade, Stage 4 upgrade, and updated Stage 5 upgrade are currently under ERCOT independent review.

2.1.3 Generation

Based on the February 2024 Generator Interconnection Status (GIS)[14] report posted on the ERCOT website on March 1, 2024, generators in the whole ERCOT system that met Planning Guide Section 6.9(1) conditions with a Commercial Operations Date (COD) prior to December 31, 2029, were added to the study base cases if not already present in the starting case. Total 89 generation units (total capacity of approximately 17,170 MW) were added to the study base cases. These generation additions are listed in the Appendix Table A.1. The renewable generation dispatches in this study were consistent with the 2024 RTP methodology:

- All solar units were dispatched up to 76% of their installed capacity.
- All battery units including the distribution connected batteries were dispatched up to 20.3% of their installed capacity.

[14] GIS Report: https://www.ercot.com/misapp/GetReports.do?reportTypeId=15933

- Wind generation in Coastal area was dispatched up to 60% of their installed capacity.
- Wind generation in Panhandle area was dispatched up to 29% of their installed capacity.
- Wind generation in other areas was dispatched up to 22% of their installed capacity.

Table 2.2 summarizes the total capacity of the online and dispatchable renewable generation in the Permian Basin region in this study.

Table 2.2: Total Capacity of Renewable Generation in Permian Basin Region

	Wind	Solar	Battery
Dispatchable Capacity (MW)	2,836	6,560	425

The status of each unit that was projected to be either indefinitely mothballed or retired at the time of the study were reviewed. The units listed in Table 2.3 were opened (turned off) in the study base cases to reflect their mothballed/retired status.

Table 2.3: List of Generation Opened to Reflect Mothballed/Retired/Forced Outage Status

Bus No	Unit Name	Capacity (MW)	Weather Zone
110941	SL_SL_G1	65.0	Coast
110942	SL_SL_G2	65.0	Coast
110943	SL_SL_G3	30.0	Coast
110944	SL_SL_G4	30.0	Coast
130121	SGMTN_SIGNALM2	6.6	Far West

2.1.4 Loads

As directed by HB 5066, the loads to be evaluated in this study would include the following:

a. Load levels forecasted in the 2022 S&P Global Permian Basin study;
b. Load currently served by temporary on-site generation not already accounted for in the S&P Global Permian Basin study;
c. Additional load currently seeking interconnection that is not otherwise included in a or b, as determined by the electric utility with the responsibility for serving the load. This should expressly include demand yet to sign a full interconnection agreement.

S&P Global Commodity Insights (formerly IHS Markit) presented the updated Permian Basin forecast of future load demand performed in 2022 to the March 2023 RPG meeting. The study provides an in-depth analysis of the oil and gas industry and provides an electricity demand forecast in the Permian Basin region through 2040. Figure 2.2 shows the S&P Global Permian Basin load forecast by year. As shown in the graph, the S&P Global Permian Basin load growth rate is higher between 2029 and 2032 with an average load growth rate of approximately 6.4%, and the load growth rate slows down starting 2033 with an average load growth rate of approximately 1% between 2032 and 2039. The graph also shows that the S&P Global Permian Basin load is peaked in 2039 with peak load of 14,705

MW. The 2030 (11,964 MW) and 2039 (14,705 MW) load level was studied in this Permian Basin Reliability Plan Study. The load in the 2038 case reflected the 2039 load level.

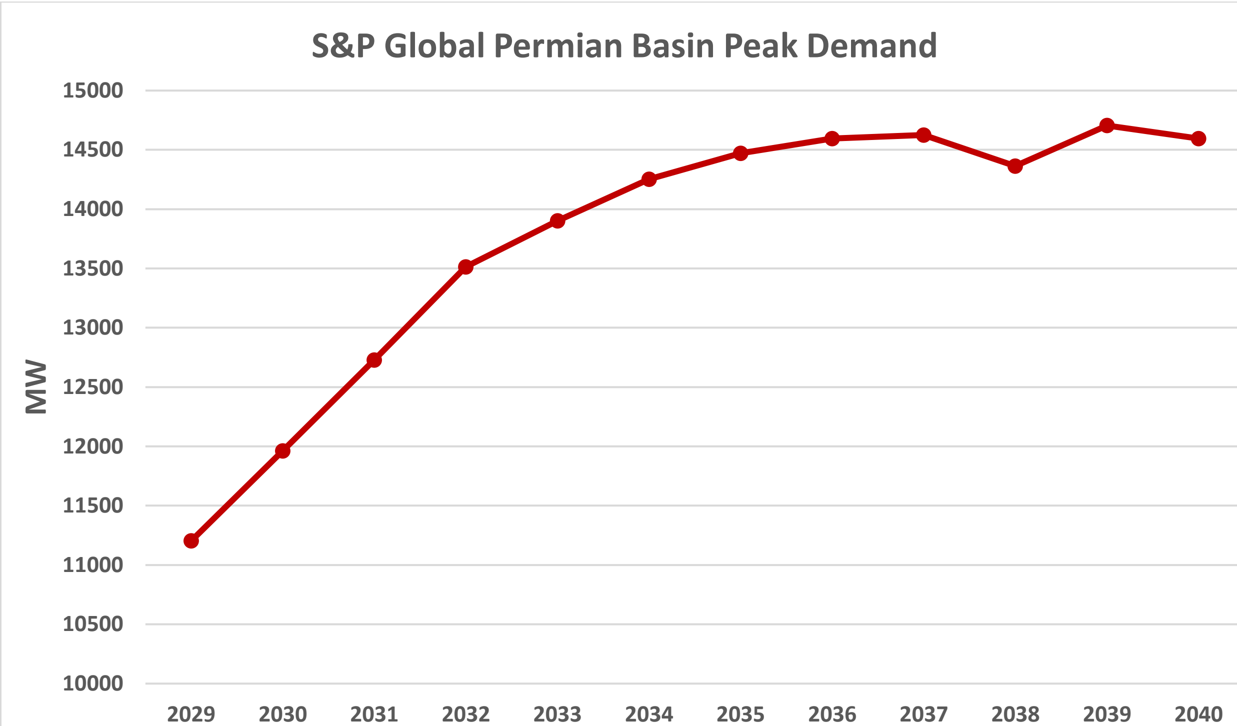

Figure 2.2: S&P Global Permian Basin Peak Demand by Year

Figure 2.3 shows the county-level S&P Global Permian Basin load forecast in 2039. As shown in Figure 2.3, the S&P Global Permian Basin loads are concentrated in the six counties in the Delaware Basin area which is remotely located at the western most part of the ERCOT system.

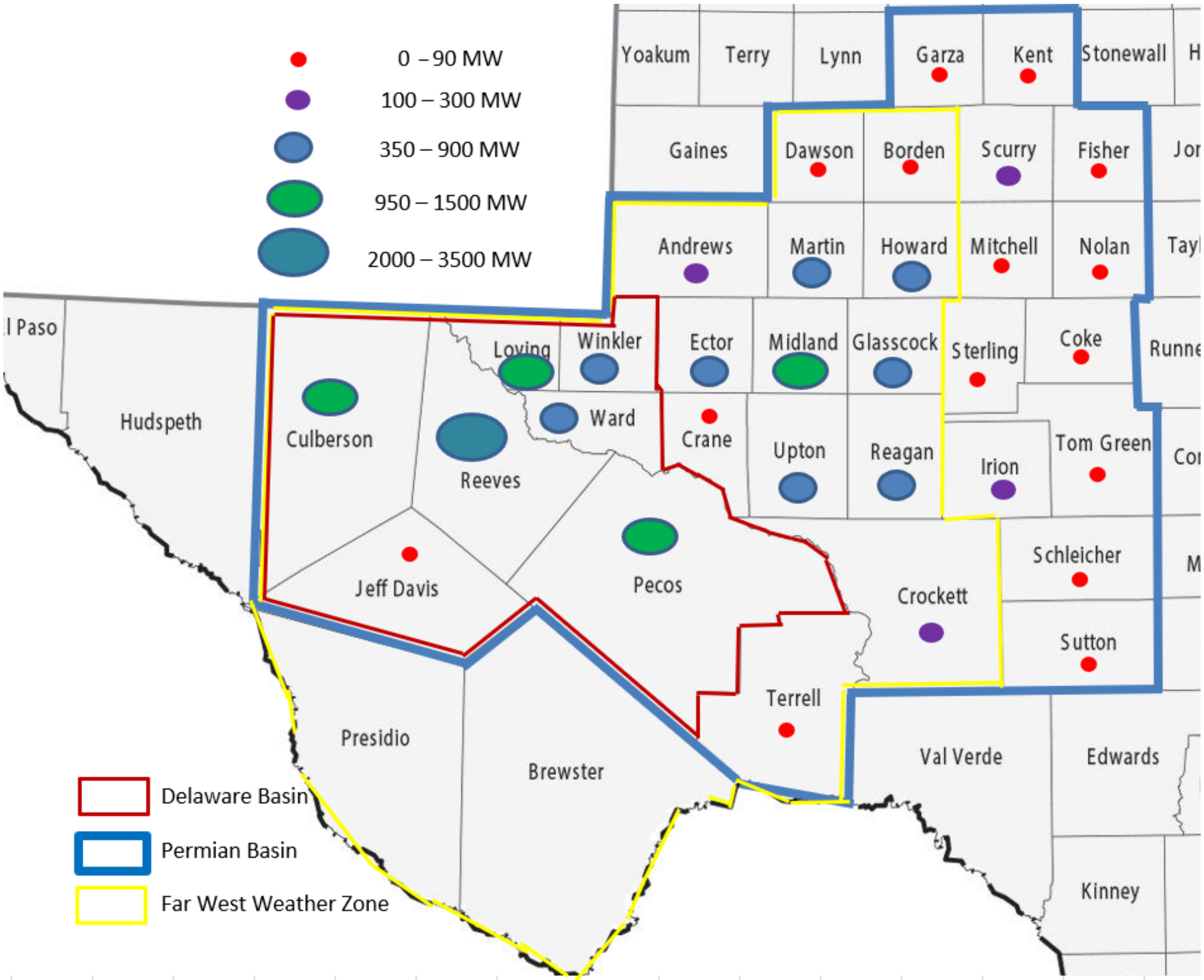

Figure 2.3: County-Level S&P Global Permian Basin Load Forecast in 2039

The TSPs relevant to the area worked together and mapped the S&P Global Permian Basin future load demand to the substation level and provided ERCOT the bus level load forecast to be used for this study.

In addition to the S&P Global Permian Basin load forecast, the TSPs relevant to the area also provided ERCOT the additional non-oil and gas loads in the Permian Basin region to be included in this study.

The load in the Permian Basin region in the starting case was updated with the substation level load derived from the demand forecast in the S&P Global study and additional non-oil and gas loads to develop the study base cases. The transmission interconnection projects jointly developed by ERCOT and the TSPs during the 2021 Permian Basin Load Interconnection Study were assumed to connect the projected new loads in the study base cases. These transmission interconnection projects were evaluated and updated in Section 5 to reflect the updated load forecast modelled in this study. Table

2.4 summarizes the total load level modelled in this Permian Basin Reliability Plan Study compared to the load in the 2019 Delaware Basin Load Integration Study, the 2021 Permian Basin Load Interconnection Study, and the 2023 RTP case.

Table 2.4: Permian Basin Region Load Comparison (MW)

	2019 Delaware Basin Study	2021 Permian Basin Study 2030 Case	2023 RTP Study 2029 Case	Permian Basin Reliability Plan 2030 Case	Permian Basin Reliability Plan 2038 Case
Permian Basin Total Load	9,771	10,527	16,577	23,659	26,400
Permian Basin Oil & Gas Load*	9,771	10,527	12,341	11,964	14,705
Additional Non-oil & Gas Load	0	0	4,236	11,695	11,695

* The Permian Basin oil & gas load from the S&P Global Permian Basin study includes residential and commercial load.

In addition to the total load in Permian Basin region modeled in this study, Table 2.5 summarizes the load level in the Delaware Basin area compared to the load in the previous ERCOT studies. The Delaware Basin area load is a subset of the Permian Basin region load.

Table 2.5: Delaware Basin Area Load Comparison (MW)

	2019 Delaware Basin Study	2021 Permian Basin Study 2030 Case	2023 RTP Study 2029 Case	Permian Basin Reliability Plan 2030 Case	Permian Basin Reliability Plan 2038 Case
Delaware Basin Total Load	5,260	4,960	7,933	10,930	13,183
Delaware Basin Oil & Gas Load*	5,260	4,960	4,884	6,439	8,692
Additional Non-oil & Gas Load	0	0	3,049	4,491	4,491

* The Delaware Basin oil & gas load from the S&P Global Permian Basin study includes residential and commercial load.

The reactive power consumption of the S&P Global Permian Basin load was modeled based on historical operational performance of existing oil and gas load in the Permian Basin region. An average power factor of 0.97 was used in this study for the S&P Global Permian Basin load. For the additional non-oil and gas load, the power factors based on the load specific information were assumed.

ERCOT categorized the additional non-oil and gas loads in the Permian Basin region into confirmed[15] loads and unconfirmed loads based on the feedback from the TSPs. Figure 2.4 shows the confirmed/unconfirmed percentage breakdown for the total 11,695 MW of additional non-oil and gas load. 39% of the additional non-oil and gas load was confirmed by the agreement contracts. 55% of additional non-oil and gas load was confirmed by the letters from the TSPs' officers. And 6% of the additional non-oil and gas load was unconfirmed. ERCOT also categorized the additional non-oil and gas loads by load type. Figure 2.5 shows the approximate load type breakdown for the total 11,695 MW of additional non-oil and gas loads.

[15] Confirmed load is the load with quantifiable evidence including industry-reputable third-party studies, signed contract, or letter from a TSP officer attesting to such load growth. The load without quantifiable evidence is categorized as unconfirmed load.

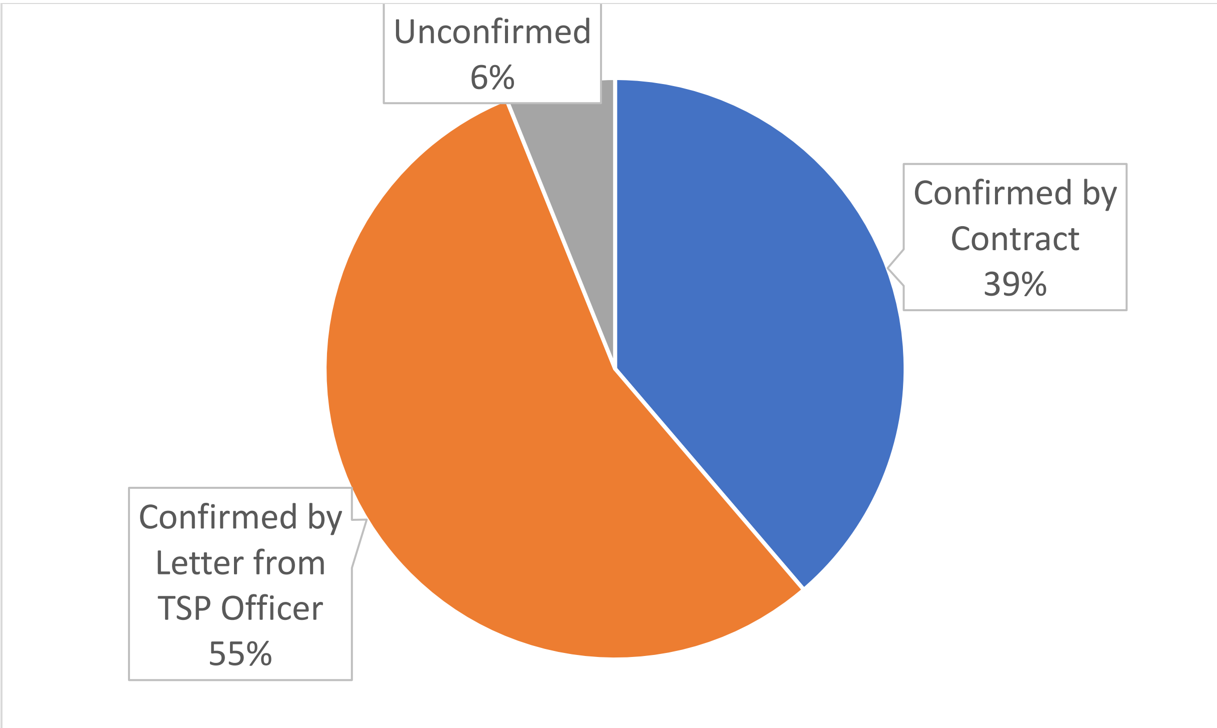

Figure 2.4: Confirmed/Unconfirmed Percentage Breakdown for the Additional Non-oil & Gas Loads

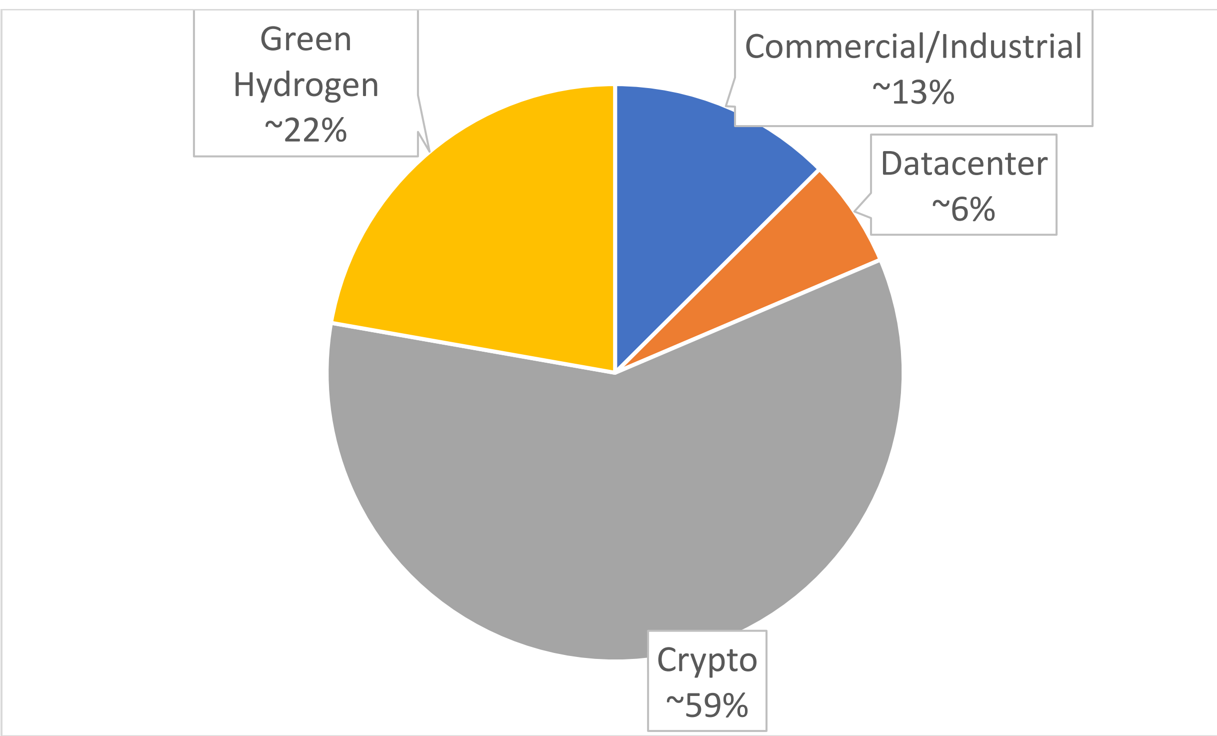

Figure 2.5: Load Type Breakdown for the Additional Non-oil & Gas Loads

Key takeaways of the load level in this Permian Basin Reliability Plan Study:

- The total load projection in the Permian Basin region is extremely high. The total load level in 2038 is comparable to that of ERCOT Coast Weather Zone and North Central Weather Zone modelled in the 2023 RTP case which is used as the starting case of this study.
- The total amount of additional non-oil and gas load projection is almost the same as the oil and gas load.
- Within the Permian Basin region, major portion of the oil and gas load is forecasted in the Delaware Basin area where transmission is relatively sparse. Especially for 2038, the load in the Delaware Basin area (8,692 MW) is significantly higher than what we have previously studied (5,260 MW).
- Permian Basin region also lacks local conventional generation compared to the North Central and Coast Weather Zones. Table 2.6 compares the load and generation in the Permian Basin region and North Central and Coast Weather Zones.

Table 2.6: Load and Conventional Generation Comparison

	2023 RTP 2029 Non-Coincident Peak Load (MW)	Load in the 2038 Starting Case of This Permian Basin Reliability Plan Study (MW)	Approximate Conventional Gen Capacity (MW)
North Central Weather Zone	32,458	28,173	28,400*
Coast Weather Zone	29,848	26,967	25,900
Permian Basin Region	16,577	26,400	2,800

* This includes the conventional generation in the East Weather Zone.

2.2 Maintenance Outage Scenario

The study included key limited maintenance outage scenario to evaluate the transmission upgrades needed under the maintenance outage conditions. ERCOT evaluated the major 345-kV level transmission outages in the Delaware Basin area since the oil and gas loads are concentrated in the Delaware Basin area and the transmission in the Delaware Basin area is relatively sparse.

The load level in the West and Far West Weather Zones was reduced to 96% of their summer peak load level to perform the maintenance outage evaluation. This scaling is meant to reflect assumed off-peak season loads based on ERCOT load forecast for future years as well as historical load in the Far West Weather Zone.

2.3 Study Assumptions for Dynamic Stability Analysis

ERCOT conducted a limited dynamic stability study utilizing the 2038 case, incorporating the transmission system upgrades identified in the steady-state analysis. In alignment with the generation shown in Appendix Table A.1, available dynamic data for generation beyond the units already included in the 2030 Summer Peak Dynamic Working Group (DWG) flat start case was utilized.

ERCOT undertook the following significant efforts to develop the study case:

- Updated dynamic data for additional generation units incorporated into the steady-state case;
- Updated the collector systems for these new units;
- Developed representative dynamic load models for new loads based on a review of existing loads in nearby areas;
- Included existing dynamic load models, under-frequency load shed, and under-voltage load shed protection models provided by relevant TSPs; and
- Made necessary updates during the flat stat case development, by comparing the DWG case with the case utilized in this study.

ERCOT employed a bookend approach for the dynamic stability studies by examining the local upgrades combined with either the 345-kV or 765-kV import path options. ERCOT did not conduct a limited dynamic stability analysis for the 500-kV import path option in this study.

2.4 Capital Cost Estimates

Capital costs estimates of each transmission upgrade at 345-kV level or lower level (138-kV and 69-kV) were provided by the TSP(s) responsible for each upgrade. ERCOT used the cost estimates provided by the TSPs to calculate total project cost estimates for various transmission upgrades. In the instance where TSPs provided the cost estimates for the same transmission upgrades, ERCOT used the highest cost estimates among the TSPs to calculate the total project cost estimates.

For the 500-kV and 765-kV EHV options, ERCOT used publicly available cost information as a general cost estimate to calculate the total project cost estimates. The general cost estimate of the EHV options used in this study as shown in Table 2.7 was referenced in the MISO 2024 Transmission Cost Estimation Guide[16] and input from the TSPs. The conductor type of 500-kV option assumed in this study is the four bundled 954 kilo circular mils (KCMil) "Cardinal" Aluminum Conductor Steel Reinforce (ACSR) conductors per circuit, or 4-954 Cardinal ACSR. However, the cost estimate of the 500-kV option is based on the conductor type of three bundled 954 KCMil ACSR conductors. This indicates the cost estimates assumed for 500-kV option in this study is relatively conservative. The conductor type of 765-kV option assumed in this study is the six bundled 795 KCMil "Tern" ACSR conductors, or 6-795 Tern ACSR.

Table 2.7: General Cost Estimate for EHV Options

	Transmission Line ($M/mile)	Substation ($M)	Transformer ($M)
500-kV Double-circuit	6.86*	94.8	15.9
765-kV Single-circuit	6.10	97.3	27.2

* A ratio of 1.4 was used to estimate the cost for 500-kV double-circuit line based on 500-kV single-circuit line.

[16] MISO Transmission Cost Estimation Guide: https://cdn.misoenergy.org/20240131%20PSC%20Item%2005%20Transmission%20Cost%20Estimation%20Guide%20for%20MTEP24%20-%20Redline631529.pdf

For new transmission lines requiring new Right of Way (ROW), ERCOT assumed a routing adder of 20% to the straight distance between two end points. For the new transmission lines proposed by the TSPs, the mileages provided by the TSPs were used in the study.

It worth to note that the cost estimates in this report are the estimates at this time in 2024 U.S. dollars. The cost estimates provided by the TSPs are initial estimates and may change with more detailed cost analysis that may include ROW study, construction outage considerations including the need for energized construction for certain transmission upgrades.

2.5 Methodology

The existing and planned transmission system was not sufficient to serve the projected loads of 23,659 MW and 26,400 MW in 2030 and 2038, respectively, in the Permian Basin region. The voltage instability issue was identified in both 2030 and 2038 study base cases under system intact (i.e., N-0) condition. As such, the reliability need analysis and project evaluation were performed step by step by adding loads in areas gradually. The study added loads in each area incrementally and identified the transmission upgrades to resolve the local reliability violations, and repeated the process in other areas and identified the transmission upgrades. After all the loads were included in the study cases, the identified transmission upgrades were re-evaluated to ensure the proposed transmission upgrades are optimal.

Due to the high load level, significant amounts of local transmission upgrades, especially in the Delaware Basin area, are needed to serve the load. Two steps were taken to address the reliability need in this study. First, identify and evaluate the local transmission upgrades to serve the load with placeholder import paths included. Second, evaluate the import paths into the Permian Basin region and re-evaluate the need for local transmission upgrades.

Two study cases, 2030 and 2038, were evaluated in this study. The existing and planned generation and transmission are the same for both cases. ERCOT started with the 2038 case to identify the reliability needs and evaluate the transmission upgrades. The transmission upgrades for 2030 are a subset of the transmission upgrades for 2038.

The following subsections list the Contingencies and Criteria used for project evaluation along with the tools used to perform each of the various analyses.

2.5.1 Contingencies and Criteria

The reliability assessments were performed based on NERC Reliability Standard TPL-001-5.1, ERCOT Protocols, and ERCOT Planning Criteria.[17]

Contingencies[18] were updated based on the changes made to the topology as described in Section 2.1 of this document. The following steady-state contingencies were simulated for the study region:

[17] ERCOT Planning Criteria: http://www.ercot.com/mktrules/guides/planning/current
[18] Details of each event and contingency category is defined in the NERC reliability standard TPL-001-5.1

- P0 (System Intact);
- P1, P2-1, P7 (N-1 conditions);
- P2-2, P2-3, P4, and P5 (Extra High Voltage only);
- P3: G-1 + N-1 (G-1: generation outages) {Permian Basin all five units, Odessa Combined Cycle Train 1}; and
- P6-2: X-1 + N-1 (X-1: 345/138-kV transformers only) {Riverton 1, Quarry Field 1, and Solstice 1}.

All 69-kV and above buses, transmission lines, and transformers in the study region were monitored (excluding generator step-up transformers) and the following thermal and voltage limits were enforced:

- Thermal
  - Rate A (normal rating) for pre-contingency conditions; and
  - Rate B (emergency rating) for post-contingency conditions.
- Voltages
  - Voltages exceeding pre-contingency and post-contingency limits; and
  - Voltage deviations exceeding 8% on non-radial load buses.

For the limited dynamic stability analysis of the 345-kV import path option, the study evaluated all 138-kV and 345-kV P1 and P7 contingencies in the West and Far West Weather Zones. Additionally, a limited dynamic stability analysis of the 765-kV import path option was conducted to simulate the 345-kV P1 and P7 contingencies as well as the contingencies associated with the 765-kV import paths.

Monitored quantities included all West and Far West 345-kV bus voltages and frequencies as well as active and reactive power for at least one unit in all generation projects in the study area.

For dynamic stability analysis, the following criteria were enforced:

- For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the system by fault clearing action or by a Remedial Action Scheme (RAS) is not considered pulling out of synchronism.
- For planning event P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any transmission system elements other than the generating unit and its directly connected facilities.
- For any operating condition in category P1 of the NERC Reliability Standard addressing Transmission System Planning Performance Requirements, voltage shall recover to 0.90 p.u. within five seconds after clearing the fault.
- For any operating condition in category P7 of the NERC Reliability Standard addressing Transmission System Planning Performance Requirements, voltage shall recover to 0.90 p.u. within ten seconds after clearing the fault.
- For any operating condition in categories P1 and P7 of the NERC Reliability Standard addressing Transmission System Planning Performance Requirements, power oscillation within the range of 0.2 Hz to 2 Hz decays with a minimum 3% damping ratio.

2.5.2 Study Tool

ERCOT utilized the following software tools to perform this study:

- PowerWorld Simulator version 23 was used for Security Constrained Optimal Power Flow (SCOPF) and steady-state contingency analysis and voltage stability analysis.
- Siemens PTI PSS/E (v.35): to perform time domain dynamic simulation of the electric network response to major disturbances.

3 Study Scope

Due to the high load level, substantial amounts of transmission upgrades would be expected to reliably serve the load. ERCOT and the relevant TSPs worked together to perform this study.

ERCOT focused on the 138-kV and above transmission upgrades and the TSPs were responsible for the 69-kV transmission upgrades. ERCOT reviewed the 69-kV transmission upgrades provided by the relevant TSPs and included the needed 69-kV transmission upgrades in this study.

The study also identified the need for significant amount of reactive power support to meet the high load demand in 2030 and 2038. As such, placeholder reactive power devices (such as capacitor banks) were added to the cases to perform this study. The reactive power devices can be proposed and added by TSPs when the load is materialized.

For the planned maintenance outage scenarios, ERCOT only considered the major 345-kV maintenance outages in the Delaware Basin area since the oil and gas loads are concentrated in the Delaware Basin area and the transmission in the Delaware Basin area is relatively sparse. Other planned maintenance outage scenarios may be evaluated in the following RTP studies or RPG reviews.

4 Reliability Need

The existing and planned transmission system was not sufficient to serve the projected loads of 23,659 MW and 26,400 MW in 2030 and 2038 respectively in the Permian Basin region. The reliability assessment results revealed that both thermal overloads and voltage instability would occur without transmission upgrades. Due to the high load level in local areas, both 2030 and 2038 study power flow base cases were not solvable. The study added loads in each area incrementally and identified the transmission upgrades to resolve the local reliability violations, and repeated the process in other areas and identified the transmission upgrades. After all the loads were included in the study cases, the identified transmission upgrades were re-evaluated to ensure the proposed transmission upgrades are optimal.

Steady-state reliability analysis was performed in accordance with NERC TPL-001-5.1 and ERCOT Planning Criteria described in Section 2.5.1 of this document. This analysis indicated that substantial amount of local transmission upgrades will be needed to serve all loads in the Permian Basin region for both 2030 and 2038. In addition to the local transmission upgrades, significant amounts of regional transmission upgrades will be needed to transfer power across the ERCOT system. The reliability needs are categorized as local reliability needs inside and outside of the Delaware Basin area to serve the loads and the import needs to transfer power across the ERCOT system.

4.1 Reliability Needs Inside Delaware Basin Area

As shown in Table 2.4, the S&P Global forecasted load inside Delaware Basin area in 2038 is 8,692 MW, which is significantly higher than what we have previously studied. The oil and gas load in the Delaware Basin area was 4,884 MW in the starting case of 2023 RTP 2029 summer peak case and 5,260 MW in the Delaware Basin Load Integration Study that ERCOT completed in 2019. In addition to the oil and gas load, additional non-oil and gas load was also forecasted in the Delaware Basin area. The existing and planned transmission system in this area was not sufficient to serve the projected load. In fact, the voltage instability issue was identified in the 2038 case under system intact (i.e., N-0) condition. Both thermal overloads, including 138-kV transmission lines and 345/138-kV transformers, and voltage instability under contingency conditions were observed in the 2030 case.

The forecasted load in the Delaware Basin area indicates that the Stage 3, Stage 4, and Stage 5 upgrades identified in the 2019 Delaware Basin Load Integration Study will be needed in 2030. In addition to the Stage 3, Stage 4, and Stage 5 upgrades, significant new transmission upgrades will be needed in the Delaware Basin area as summarized below. This does not include the significant regional transmission upgrades that will be needed to transfer power across the ERCOT system to serve Permian Basin region load.

- Add approximately 257 miles of new 345-kV double-circuit transmission lines
- Upgrade approximately 16 miles of the existing 345-kV lines and add second circuits
- Add eight new 345/138-kV substations with 18 new 345/138-kV transformers
- Add approximately 169 miles of new 138-kV transmission lines
- Upgrade approximately 68 miles of the existing 138-kV transmission lines
- Convert approximately 30 miles of the existing 69-kV transmission lines to 138-kV

The details of these transmission upgrades are described in Section 5 and divided into the following three areas:

- Loving and Winkler Counties
- Culberson and Reeves Counties
- Pecos County

4.2 Reliability Needs Outside Delaware Basin Area

As shown in Table 2.3 and Table 2.4, within the Permian Basin region, oil and gas load growth is shifting to the Delaware Basin area. As a result, the oil and gas load outside Delaware Basin area was decreased when compared to the previous 2023 RTP study as shown in Table 4.1. In addition, significant amount of additional non-oil and gas loads were also added in the area.

Table 4.1: Permian Basin Load Comparison Outside Delaware Basin Area (MW)

	2023 RTP Study 2029 Case	Permian Basin Reliability Plan 2030 Case	Permian Basin Reliability Plan 2038 Case
Total Load Outside Delaware Basin Area	8,644	12,729	13,217
Oil & Gas Load Outside Delaware Basin Area	7,457	5,525	6,013
Additional Non-oil & Gas Load Outside Delaware Basin Area	1,187	7,204	7,204

The reliability needs outside of the Delaware Basin area are mainly driven by the additional non-oil and gas loads in the area. In a few areas, additional transmission upgrades need to be proposed prior to addition of the projected loads due to the size of the loads in local areas. The reliability needs outside of the Delaware Basin area are summarized as below:

- Upgrade approximately 98 miles of the existing 345-kV double-circuit transmission lines
- Upgrade approximately 84 miles of the existing 345-kV lines and add second circuits
- Add two new 345/138-kV substations with four new 345/138-kV transformers
- Add approximately 17 miles of new 138-kV transmission lines
- Upgrade approximately 179 miles of the existing 138-kV transmission lines
- Convert approximately 200 miles of the existing 69-kV transmission lines to 138-kV

The details of these transmission upgrades outside of the Delaware Basin area are mainly divided into the following four areas with more details in Section 5:

- Andrews and Ector Counties
- Martin, Howard, Midland, and Glasscock Counties
- Mitchell, Scurry, Nolan, Coke, and Sterling Counties
- Reagan, Crockett, and Sutton Counties

4.3 Import Paths Need

Due to the significant amounts of loads and lack of local conventional generation in the Permian Basin region, significant amounts of the regional transmission upgrades will be needed to transfer power to the Permian Basin region across the ERCOT system. The study indicates multiple import paths would be needed to transfer power to the Permian Basin region across the ERCOT system to reliably serve the projected load after the evaluation of the projected generation in the Permian Basin region.

Both 345-kV and EHV options (500-kV or 765-kV) were evaluated as the import paths to transfer power across the ERCOT system. The import paths are summarized as below. The details of the import paths are described in Section 5.

345-kV Import Paths:

- Four new 345-kV double-circuit import paths, plus a short path from the Panhandle
- Approximately 1,676 miles of new 345-kV double-circuit transmission lines in total
- Additional new dynamic reactive devices (700 MVAr)

500-KV Import Paths:

- Three new 500-kV double-circuit import paths, plus a short 345-kV path from the Panhandle
- Approximately 1,225 miles of new 500-kV double-circuit transmission lines and 115 miles of new 345-kV double-circuit lines in total
- Additional new dynamic reactive devices (350 MVAr)

765-KV Import Paths:

- Three new 765-kV single-circuit import paths
- Approximately 1,255 miles of new 765-kV single-circuit transmission lines in total
- Additional new dynamic reactive devices (350 MVAr)

5 Project Evaluations

Significant amounts of transmission projects were evaluated in this study to address the reliability needs identified in Section 4. In the project need evaluation, ERCOT considered several factors including of the need for new ROW, transmission project cost, feasibility of construction, future generation expansion capability, impact of loss of major 345-kV substations and maintenance outage impact. Additional considerations include connecting transmission to potential future generation areas and capability to import those generation to the Permian Basin region to serve the forecasted Permian Basin load and also potentially export renewable generation in West Texas to the other load growth areas. Many candidate options were ruled out during the design process when these major consideration factors were evaluated. As such, the transmission upgrades described in this section are ones that ERCOT proposed.

All the transmission upgrades were evaluated for N-1, G-1 + N-1, X-1 + N-1, and N-1-1 of maintenance outages specified in the Section 2.5.1 and Section 3.

All the transmission upgrades that ERCOT evaluated and proposed are described in this section. Most of the transmission upgrades are needed for both 2030 and 2038. The transmission upgrades are labeled as 2038 if they are only needed for 2038.

5.1 Transmission Upgrades Inside Delaware Basin Area

Loads in the Delaware Basin area are mainly concentrated in six counties in Far West Weather Zone: Culberson, Loving, Pecos, Reeves, Ward, and Winkler. The S&P Global Permian Basin load forecast inside Delaware Basin area are 6,439 MW in 2030 and 8,692 MW in 2038, which is significantly higher than the load level of 4,884 MW in the starting case of this study. In addition to the oil and gas loads, 4,491 MW of additional non-oil and gas load was also included in 2030 and 2038 cases which is 1,442 MW more than the non-oil and gas load in the starting case. Overall, an incremental of 5,250 MW of load was modeled in 2038 when compared to the starting case. The Delaware Basin area load comparison is summarized in Table 2.5. Figure 5.1 shows the transmission upgrades inside the Delaware Basin area.

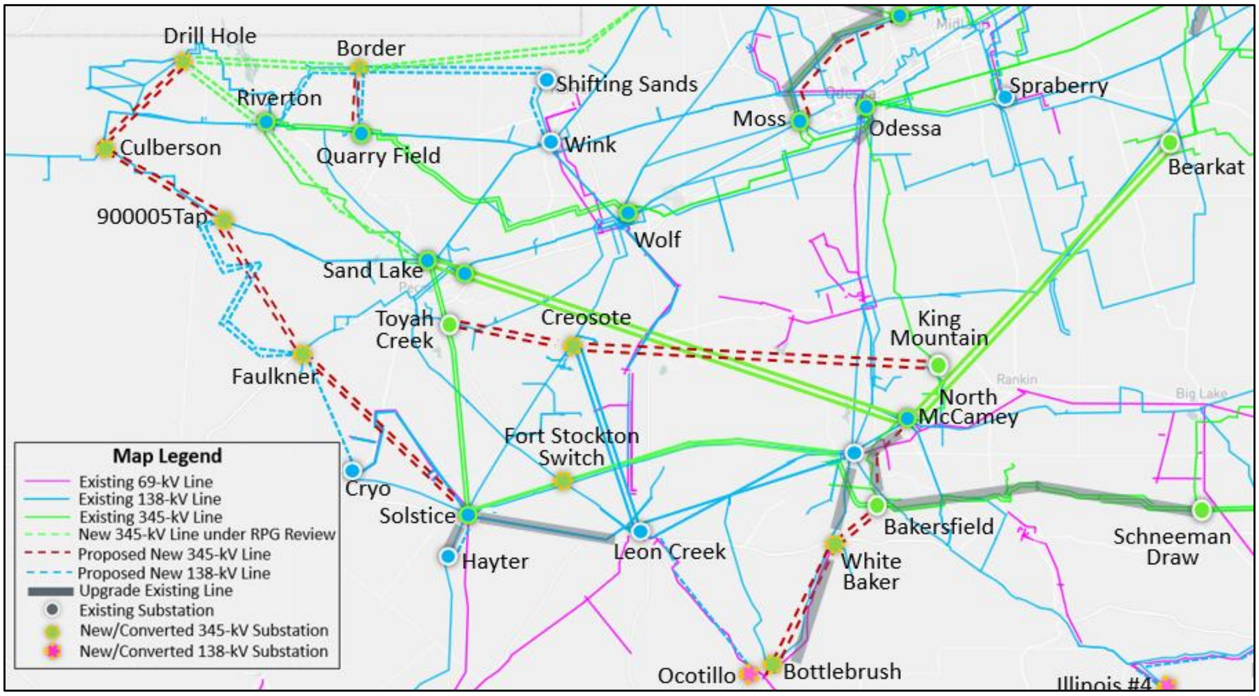

Figure 5.1: Transmission Upgrades Inside Delaware Basin Area

The transmission upgrades inside of the Delaware Basin area are divided into the following three areas:

- Loving and Winkler Counties
- Culberson and Reeves Counties
- Pecos County

5.1.1 Loving and Winkler Counties

The oil and gas loads included in this study in the Loving and Winkler Counties in 2038 are significantly higher than the loads modelled in the starting case of 2023 RTP study. Table 5.1 summarized the loads comparison.

Table 5.1: Oil and Gas Loads Comparison in Loving and Winkler Counties

County	2023 RTP Study 2029 Case (MW)	Permian Basin Reliability Plan 2030 (MW)	Permian Basin Reliability Plan 2038 (MW)
Loving	809	974	1,301
Winkler	519	560	773

Among these total load projections, new oil and gas loads are forecasted at north of the existing Wink – Quarry Field – Riverton 138-kV path without existing transmission infrastructures. New transmission lines are required to connect the new oil and gas loads to the existing transmission grid. In addition to the new load connection project, upgrades associated with existing transmission facilities were also identified to address the reliability needs in Loving and Winkler Counties. Transmission upgrade L1 is proposed to connect and reliably serve the new oil and gas loads. Transmission upgrade L2 is proposed to address the thermal overloads of the Quarry Field and Riverton 345/138-kV transformers in the area.

Upgrade L1:

- Connect the new load buses 900004, 900007, 900015, and 900066 to Border and Shifting Sands 138-kV substations to form a 138-kV double-circuit loop with a normal and emergency rating of at least 614 MVA per circuit. This transmission line will require approximately 39 miles of new ROW;
- Add Quarry Field – Border 138-kV second circuit with a normal and emergency rating of at least 614 MVA;
- Add Wink – Shifting Sands 138-kV second circuit with a normal and emergency rating of at least 614 MVA; and
- Add Riverton – Border 138-kV second circuit with a normal and emergency rating of at least 614 MVA.

The estimated cost of the upgrade L1 is approximately $136.0 million. The upgrade L1 will require approximately 39 miles of new ROW. The Upgrade L1 is needed in 2030.

Upgrade L2:

- Establish a new Border 345/138-kV substation at the existing Border 138-kV substation and install two new 345/138-kV transformers, each transformer with normal and emergency ratings of at least 668 MVA and 750 MVA;
- Loop the Stage 5 upgrade (identified in the 2019 Delaware Basin Load Integration Study and is currently under RPG review) of the new Clearfork – Drill Hole 345-kV double-circuit transmission line into the new Border 345-kV substation; and
- Add a new Border – Quarry Field 345-kV double-circuit line with a normal and emergency rating of at least 2988 MVA per circuit. This transmission line will require approximately 12 miles of new ROW.

The estimated cost of the upgrade L2 is approximately $95.0 million. The upgrade L2 will require approximately 12 miles of new ROW. The Upgrade L2 is needed in 2038.

5.1.2 Culberson and Reeves Counties

The oil and gas loads in the Culberson and Reeves Counties are significantly higher than the loads modelled in the starting case of 2023 RTP study. Reeves County has the highest oil and gas load projection in the study area, 2,363 MW in 2030 and 3,199 MW in 2038. The oil and gas loads in the Culberson County are more than doubled when compared to the loads in the starting case as shown in Table 5.2.

Table 5.2: Oil and Gas Loads Comparison in Culberson and Reeves Counties

County	2023 RTP Study 2029 Case (MW)	Permian Basin Reliability Plan 2030 (MW)	Permian Basin Reliability Plan 2038 (MW)
Culberson	489	1,011	1,389
Reeves	1,938	2,363	3,199

In addition to the oil and gas loads, additional non-oil and gas loads were also projected in the Reeves County that resulted in the need for significant amounts of new transmission lines and transformers in the area.

New 138-kV transmission lines are proposed to connect the new oil and gas loads to the existing transmission grid. Several additional transmission upgrades are proposed to address both thermal and voltage violations in the area.

Upgrade L3:

- Connect new load buses 900005, 900111, 900023, 900012, 900021, and 900038 together through new 138-kV double-circuit lines, and then connect new load bus 900005 to ONC900005_TAP and connect new load bus 900038 to Faulkner through new 138-kV double-circuit lines to form a 138-kV double-circuit loop: ONC900005_TAP – 900005 – 900111 – 900023 – 900012 – 900021 – 900038 – Faulkner. The normal and emergency rating of the new 138-kV double-circuit lines is at least 614 MVA per circuit. These new transmission lines will require approximately 60 miles of new ROW.

The estimated cost of the upgrade L3 is approximately $120.8 million. The upgrade L3 will require approximately 60 miles of new ROW. The Upgrade L3 is needed in 2030.

Upgrade L4:

- Connect new load bus 900108 to Faulkner and Cryo 138-kV substations to form a 138-kV single-circuit loop with a normal and emergency rating of at least 614 MVA. This new transmission line will require approximately 23 miles of new ROW.

The estimated cost of the upgrade L4 is approximately $44.9 million. The upgrade L4 will require approximately 23 miles of new ROW. The Upgrade L4 is needed in 2030.

Upgrade L5:

- Establish a new Culberson 345/138-kV substation at the existing Culberson Switch and install two new 345/138-kV transformers, each transformer with normal and emergency ratings of at least 668 MVA and 750 MVA;

- Establish a new ONC900005_TAP 345/138-kV substation and install two new 345/138-kV transformers, each transformer with normal and emergency ratings of at least 668 MVA and 750 MVA. The ONC900005_TAP 138-kV substation is cutting into the existing Sand Lake – Culberson 138-kV double-circuit line;
- Establish a new Faulkner 345/138-kV substation at the existing Faulkner station and install two new 345/138-kV transformers, each transformer with normal and emergency ratings of at least 668 MVA and 750 MVA;
- Add a new Drill Hole – Culberson 345-kV double-circuit line with a normal and emergency rating of at least 2988 MVA per circuit. This transmission line will require approximately 22 miles of new ROW;
- Add a new Culberson – ONC900005_TAP 345-kV double-circuit line with a normal and emergency rating of at least 2988 MVA per circuit. This transmission line will require approximately 25 miles of new ROW;
- Add a new ONC900005_TAP – Faulkner 345-kV double-circuit line with a normal and emergency rating of at least 2988 MVA per circuit. This transmission line will require approximately 32 miles of new ROW; and
- Add a new Faulkner – Solstice 345-kV double-circuit line with a normal and emergency rating of at least 2988 MVA per circuit. This transmission line will require approximately 40 miles of new ROW.

The estimated cost of the upgrade L5 is approximately $725.3 million. The upgrade L5 will form a new 345-kV double-circuit loop, requiring approximately 119 miles of new ROW, with additional 345/138-kV transformer capacity to address the reliability issues in the area. The Upgrade L5 is needed in 2030.

Upgrade L6:

- Upgrade the existing Cowpen – Birds of Pray Tap 138-kV transmission line with a normal and emergency rating of at least 717 MVA. This upgrade is not needed in the EHV import path options.

The estimated cost of the upgrade L6 is approximately $2.0 million. The Upgrade L6 is needed in 2038.

5.1.3 Pecos County

The oil and gas load in the Pecos County also has significant increase when compared to the starting case of 2023 RTP study. Table 5.3 summarizes the loads comparison.

Table 5.3: Oil and Gas Loads Comparison in Pecos County

County	2023 RTP Study 2029 Case (MW)	Permian Basin Reliability Plan 2030 (MW)	Permian Basin Reliability Plan 2038 (MW)
Pecos	627	976	1,281

In addition to the oil and gas load, over 2,000 MW of additional non-oil and gas load was also modelled in both 2030 and 2038 cases.

The total load, oil and gas loads plus the additional non-oil and gas large loads interconnection along the Yucca – Solstice 138-kV path is over 1,000 MW in 2038 case. This drives the need for new 345-kV source near the existing Creosote substation which is in the middle of Yucca (Wolf) – Solstice 138-kV path. Several options, including looping the approved Stage 2 upgrade of North McCamey – Sand Lake 345-kV double-circuit line into Creosote (or Coyanosa), and adding new 345-kV double-circuit line from King Mountain to Creosote (or Coyanosa) to Toyah Creek, were considered. The study showed that adding a new 345-kV double-circuit line from King Mountain to Creosote to Toyah Creek (upgrade L7) is the best option to address the reliability issues in the area.

Upgrade L7:

- Establish a new Creosote 345/138-kV substation at the existing Creosote 138-kV substation and install three new 345/138-kV transformers, each transformer with normal and emergency ratings of at least 668 MVA and 750 MVA;
- Add a new King Mountain – Creosote 345-kV double-circuit line with a normal and emergency rating of at least 2988 MVA per circuit. This transmission line will require approximately 71 miles of new ROW. This upgrade is not needed in the EHV import path options; and
- Add a new Creosote – Toyah Creek 345-kV double-circuit line with a normal and emergency rating of at least 2988 MVA per circuit. This transmission line will require approximately 23 miles of new ROW.

The estimated cost of the upgrade L7 is approximately $575.7 million. The upgrade L7 will require approximately 94 miles of new ROW. The Upgrade L7 is needed in 2030.

Upgrade L8:

- Upgrade the existing Creosote – Trans Pecos Tap 138-kV transmission line with a normal and emergency rating of at least 717 MVA.

The TSP has scheduled to upgrade this short 138-kV transmission line. No cost estimate is needed for the upgrade L8. The Upgrade L8 is needed in 2030.

Upgrade L9:

- Establish a new FT Stockton Switch 345/138-kV substation at the existing FT Stockton Switch and install three new 345/138-kV transformers, each transformer with normal and emergency ratings of at least 668 MVA and 750 MVA; and
- Loop the existing Solstice – Bakersfield 345-kV double-circuit line into the new FT Stockton Switch 345-kV substation.

The estimated cost of the upgrade L9 is approximately $104.1 million. The Upgrade L9 is needed in 2038.

Upgrade L10:

- Bypass the existing Solstice phase shifting transformer and upgrade the existing Solstice – FT Stockton Plant 138-kV transmission line with normal and emergency ratings of at least 650 MVA and 717 MVA.

The estimated cost of the upgrade L10 is approximately $44.6 million. The Upgrade L10 is needed in 2030.

Upgrade L11:

- Rebuild the existing Solstice – Hayter Tap 138-kV line to double-circuit with normal and emergency ratings of at least 650 MVA and 719 MVA per circuit;
- Move the large load as well as LCRA load at Hayter Tap to Hayter; and
- Radially serve the loads at Hayter from Solstice.

The estimated cost of the upgrade L11 is approximately $10.5 million. The Upgrade L11 is needed in 2030.

Upgrade L12:

- Convert the existing 16th Street – FT Stockton – Pinion – Ocotillo 69-kV line to 138kV with a normal and emergency rating of at least 717 MVA;
- Tie the Ocotillo 138-kV substation to the Bottlebrush 138-kV substation through a new 138-kV transmission line (approximately 2 miles) with a normal and emergency rating of at least 717 MVA. This new line will share the structures with an existing transmission line in the same area;
- Expand the Ocotillo substation and move the 16th Street 138/69-kV transformer to Ocotillo; and
- Upgrade the existing 16th Street – Alamo Street 138-kV transmission line with a normal and emergency rating of at least 717 MVA.

The estimated cost of the upgrade L12 is approximately $87.9 million. The Upgrade L12 is needed in 2030.

Upgrade L13:

- Establish a new White Baker 345/138-kV substation at the existing White Baker 138-kV substation and install two new 345/138-kV transformers, each transformer with normal and emergency ratings of at least 668 MVA and 750 MVA;
- Establish a new Bottlebrush 345/138-kV substation near the existing Century 138-kV substation and install two new 345/138-kV transformers, each transformer with normal and emergency ratings of at least 668 MVA and 750 MVA;

- Add a new Bakersfield – White Baker 345-kV double-circuit line with a normal and emergency rating of at least 2988 MVA per circuit. This transmission line will require approximately 11 miles of new ROW;
- Add a new White Baker – Bottlebrush 345-kV double-circuit line with a normal and emergency rating of at least 2988 MVA per circuit. This transmission line will require approximately 23 miles of new ROW;
- Upgrade the existing White Baker – Girvin 138-kV transmission line with a normal and emergency rating of at least 717 MVA;
- Terminal equipment upgrade of the existing White Baker – Sherbino II Wind Farm 138-kV line; and
- Upgrade the existing White Baker – Bottlebrush 138-kV transmission line with a normal and emergency rating of at least 717 MVA. This upgrade is not needed in the EHV import path options.

The estimated cost of the upgrade L13 is approximately $365.6 million. The upgrade L13 will require approximately 34 miles of new ROW. The Upgrade L13 is needed in 2030.

Upgrade L14:

- Upgrade the existing Bakersfield – Nevill Road 345-kV transmission line and add a second circuit with a normal and emergency rating of at least 2988 MVA per circuit; and
- Upgrade the existing Nevill Road – North McCamey 345-kV transmission line and add a second circuit with a normal and emergency rating of at least 2988 MVA per circuit.

The estimated cost of the upgrade L14 is approximately $119.6 million. The Upgrade L14 is needed in 2030.

Upgrade L15:

- Upgrade the existing Bakersfield – Cedar Caynon – Noelke – Schneeman Draw 345-kV double-circuit transmission line with a normal and emergency rating of at least 2988 MVA per circuit.

The estimated cost of the upgrade L15 is approximately $192.7 million. The Upgrade L15 is identified in the EHV import paths options of the 2038 study case and it is not needed in the 345-kV import path option.

5.2 Transmission Upgrades Outside Delaware Basin Area

The transmission upgrades outside the Delaware Basin area are mainly driven by the additional non-oil and gas loads in the area.

The transmission upgrades outside the Delaware Basin area are divided into the following four areas:

- Andrews and Ector Counties

- Martin, Howard, Midland, and Glasscock Counties
- Mitchell, Scurry, Nolan, Coke, and Sterling Counties
- Reagan, Crockett, and Sutton Counties

5.2.1 Andrews and Ector Counties

The following transmission upgrades were identified to address the thermal overloads of the existing transmission lines. Figure 5.2 shows the map of these transmission upgrades.

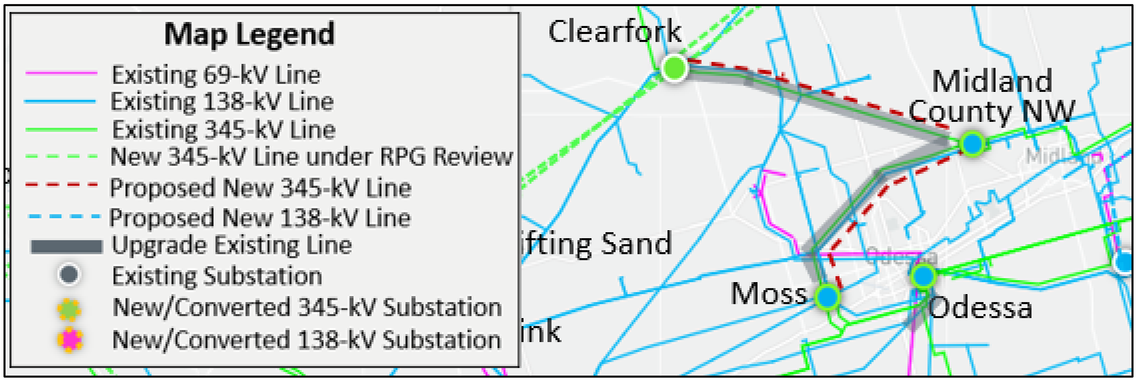

Figure 5.2: Transmission Upgrades in Andrews and Ector Counties

Upgrade L16:

- Upgrade the existing Moss – Midland County NW 345-kV line and add a second circuit with a normal and emergency rating of at least 2988 MVA per circuit;
- Upgrade the existing Gardendale – Clearfork 345-kV line and add a second circuit with a normal and emergency rating of at least 2988 MVA per circuit; and
- Upgrade the existing Gardendale – Telephone Road 345-kV line and add a second circuit with a normal and emergency rating of at least 2988 MVA per circuit.

The estimated cost of the upgrade L16 is approximately $649.0 million. The Upgrade L16 is needed in 2030. The Upgrade L16 is not needed in the EHV import path options.

Upgrade L17:

- Upgrade the existing Odessa – Reiter 138kV double-circuit line with a normal and emergency rating of at least 614 MVA per circuit.

The estimated cost of the upgrade L17 is approximately $13.0 million. The Upgrade L17 is needed in 2030.

5.2.2 Martin, Howard, Midland, and Glasscock Counties

The following transmission upgrades were proposed to address the reliability violations in this area. Figure 5.3 shows the map of these transmission upgrades.

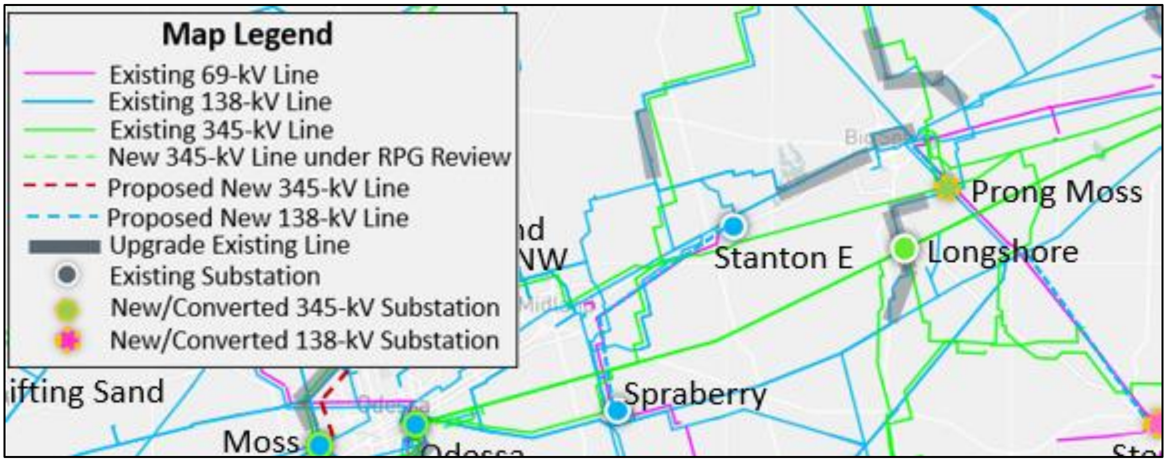

Figure 5.3: Transmission Upgrades in Martin, Howard, Midland, and Glasscock Counties

Upgrade L18:

- Convert the existing Stanton East – Midland Basin – Spraberry 69-kV transmission line to 138-kV with a normal and emergency rating of at least 614 MVA.

The estimated cost of the upgrade L18 is approximately $92.0 million. The Upgrade L18 is needed in 2030.

Upgrade L19:

- Upgrade the existing Grady – Coronado Midstream Tap – Sales Ranch 138-kV transmission line with a normal and emergency rating of at least 614 MVA.

The estimated cost of the upgrade L19 is approximately $22.0 million. The Upgrade L19 is needed in 2030.

Upgrade L20:

- Establish a new Prong Moss 345/138-kV substation, approximately 7.0 miles south of the existing Falcon Seaboard generation station and install two new 345/138-kV transformers with normal and emergency ratings of at least 668 MVA and 750 MVA. The Prong Moss 345-kV substation will be cutting into the existing Morgan Creek – Falcon Seaboard 345-kV transmission line;
- Loop the existing Elbow – Bulldog 138-kV transmission line into the Prong Moss 138-kV substation and upgrade the Elbow – Prong Moss 138-kV line section with a normal and emergency rating of at least 614 MVA;
- Loop the existing Hill Crest – McDonald Road 138-kV transmission line into Prong Moss 138-kV substation;
- Convert the existing Big Spring – Signal Mountain 69-kV transmission line to 138-kV with a normal and emergency rating of at least 614 MVA;

- Connect the converted Signal Mountain to Prong Moss 138-kV substation. This will require approximately 2 miles of new ROW;
- Construct a new Chalk 138-kV substation near the existing Chalk 69-kV substation and loop the existing McDonald Road – Navigation 138-kV transmission line into the new Chalk 138-kV substation;
- Upgrade the existing Eiland – Elbow 138-kV transmission line with a normal and emergency rating of at least 614 MVA; and
- Upgrade the existing Luther – Bulldog 138-kV transmission line with a normal and emergency rating of at least 614 MVA.

The estimated cost of the upgrade L20 is approximately $249.0 million. The upgrade L20 will require approximately 2 miles of new ROW. The Upgrade L20 is needed in 2030.

Upgrade L21:

- Upgrade the existing Natural Dam – Beals Creek 138-kV transmission line with a normal and emergency rating of at least 614 MVA; and
- Upgrade the existing Big Springs – Steer 138-kV transmission line with a normal and emergency rating of at least 614 MVA.

The estimated cost of the upgrade L21 is approximately $41.0 million. The Upgrade L21 is needed in 2030.

5.2.3 Mitchell, Scurry, Nolan, Coke, and Sterling Counties

The following transmission upgrades were proposed to address the reliability violations in this area. Figure 5.4 shows the map of these transmission upgrades.

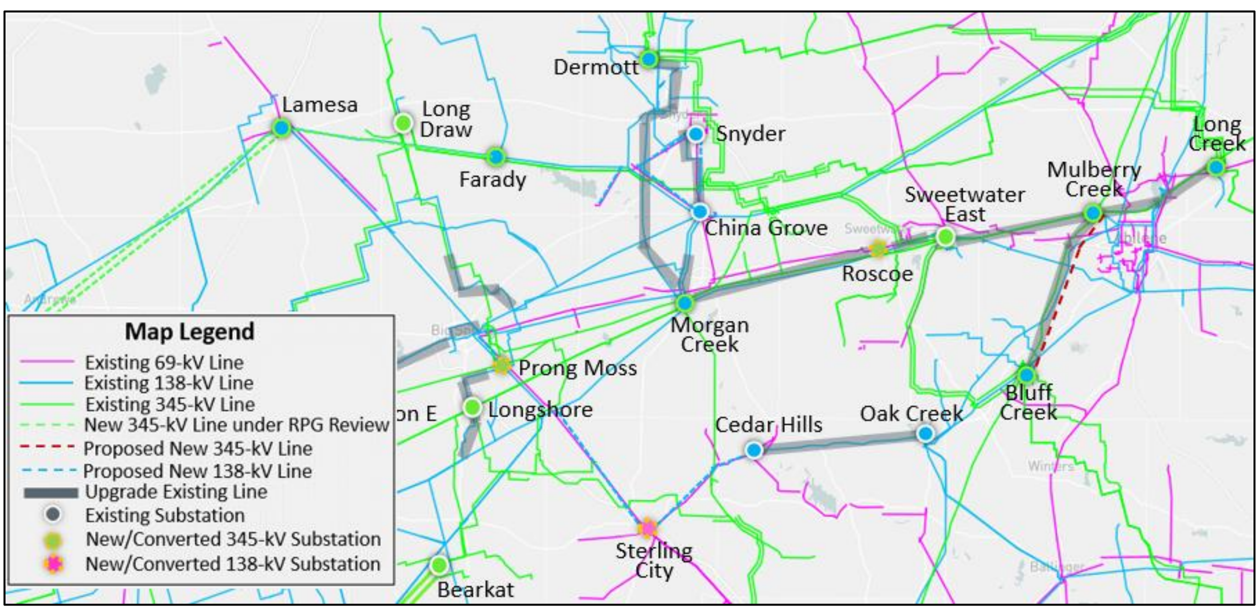

Figure 5.4: Transmission Upgrades in Mitchell, Scurry, Nolan, Coke, and Sterling Counties

Upgrade L22:

- Add a new Ranger – Frontier 138-kV transmission line (second 138-kV transmission line) with a normal and emergency rating of at least 614 MVA. This new line will require approximately 4 miles of new ROW;
- Upgrade the existing Ranger – Sun – Golden Switch – Dermott 138-kV transmission line with a normal and emergency rating of at least 614 MVA;
- Upgrade the existing Sun – Sacroc 138-kV transmission line with a normal and emergency rating of at least 614 MVA; and
- Upgrade the existing Deep Creek – China Grove – 900126 138-kV transmission line with a normal and emergency rating of at least 614 MVA.

The estimated cost of the upgrade L22 is approximately $173.0 million. The upgrade L22 will require approximately 4 miles of new ROW. The Upgrade L22 is needed in 2030.

Upgrade L23:

- Convert the existing Snyder – Scurry – China Grove and Snyder – Amoco Tap – China Grove 69-kV transmission lines to 138-kV with a normal and emergency rating of at least 614 MVA.

The estimated cost of the upgrade L23 is approximately $196.0 million. The Upgrade L23 is needed in 2030.

Upgrade L24:

- Upgrade the existing Cattleman (Morgan Creek) – Champion Creek/Bitter Creek – Sweetwater East 345-kV double-circuit line with a normal and emergency rating of at least 2988 MVA per circuit; and
- Upgrade the existing Long Creek – Sweetwater East 345-kV double-circuit transmission line with a normal and emergency rating of at least 2988 MVA per circuit;

The estimated cost of the upgrade L24 is approximately $607.9 million. The Upgrade L24 is needed in 2030.

Upgrade L25:

- Establish a new Roscoe 345/138-kV substation near the existing Sweetwater Tap 138-kV substation and install two new 345/138-kV transformers with normal and emergency ratings of at least 668 MVA and 750 MVA;
- Loop the existing Cattleman (Morgan Creek) – Champion Creek/Bitter Creek – Sweetwater East 345-kV double-circuit line into Roscoe 345-kV substation. This will require approximately 2 miles of new ROW;
- Convert the existing Plowboy – Eskota 69-kV transmission line to 138-kV with a normal and emergency rating of at least 394 MVA;

- Loop the converted Plowboy – Eskota 138-kV transmission line into Roscoe near the Sweetwater substation. This will require approximately 3 miles of new ROW; and
- Move the Eskota 138/69-kV transformer #1 to Plowboy.

The estimated cost of the upgrade L25 is approximately $143.0 million. The upgrade L25 will require approximately 5 miles of new ROW. The Upgrade L25 is needed in 2030.

Upgrade L26:

- Upgrade the existing Bluff Creek – Abilene Mulberry Creek 345-kV transmission line and add a second circuit with a normal and emergency rating of at least 2988 MVA per circuit.

The estimated cost of the upgrade L26 is approximately $136.9 million. The Upgrade L26 is needed in 2030.

Upgrade L27:

- Convert the existing Cedar Hill – Sterling City – Kinnebrew POI – Chalk 69-kV transmission line including Silver Loop to 138-kV with a normal and emergency rating of at least 484 MVA. According to one of the TSPs relevant to this upgrade, new facilities associated with Cedar Hill and Sterling City will be at least 717 MVA for normal and emergency rating; and
- Upgrade the existing Oak Creek – Cedar Hills 138-kV transmission line with a normal and emergency rating of at least 484 MVA. According to the TSP, any new facilities related to this upgrade will be at least 717 MVA for normal and emergency rating. The TSP also informed the potential retirement of the existing Oak Creek substation, indicating that all lines will be terminated into the Nicole substation.

The estimated cost of the upgrade L27 is approximately $226.4 million. The Upgrade L27 is needed in 2030.

5.2.4 Reagan, Crockett, and Sutton Counties

The following transmission upgrades were proposed to address the reliability violations in this area. Figure 5.5 shows the map of these transmission upgrades.

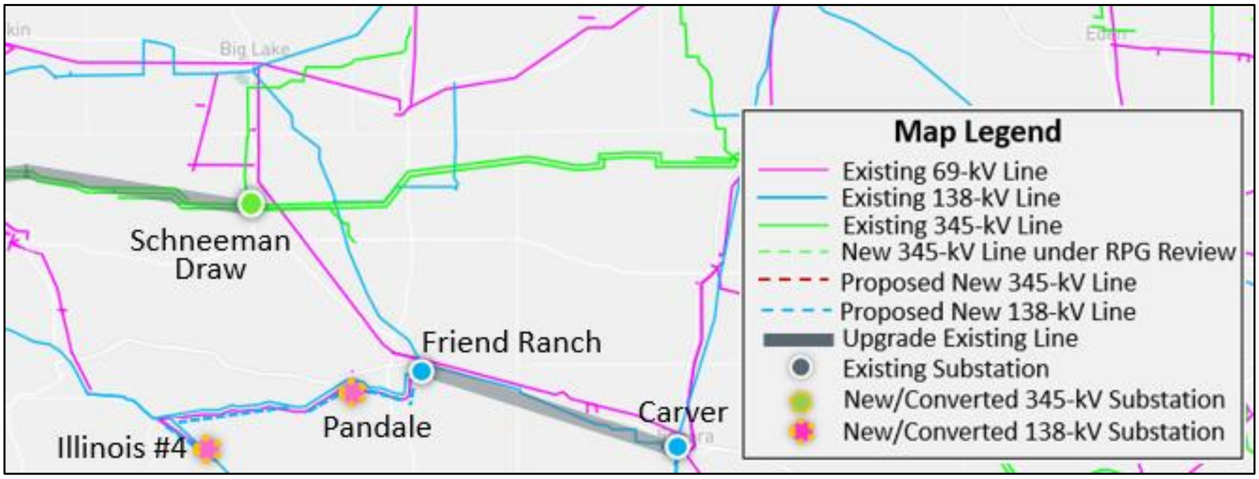

Figure 5.5: Transmission Upgrades in Reagan, Crockett, and Sutton Counties

Upgrade L28:

- Connect the new load bus 900052 to Big Lake 138-kV substation to form a 138-kV loop with a normal and emergency rating of at least 484 MVA. This will require approximately 8 miles of new ROW.

The estimated cost of the upgrade L28 is approximately $22.5 million. The upgrade L28 will require approximately 8 miles of new ROW. The Upgrade L28 is needed in 2030.

Upgrade L29:

- Upgrade the existing Friend Ranch – Carver 138-kV transmission line with normal and emergency ratings of at least 650 MVA and 719 MVA.

The estimated cost of the upgrade L29 is approximately $60.1 million. The Upgrade L29 is needed in 2030.

Upgrade L30:

- Convert the existing Illinois #4 – Pandale – Ozona – Friend Ranch 69-kV transmission line to 138-kV with a normal and emergency rating of at least 484 MVA. According to the TSP, any new facilities related to this upgrade will be at least 717 MVA for normal and emergency rating;
- Expand the Ozona substation and move the Illinois #4 138/69-kV transformer to Ozona; and
- Expand the Pandale substation and build a new 138-kV tie between Pandale and Stockman substation (approximately less than 1 mile) with a normal and emergency rating of at least 484 MVA. According to the TSP, any new facilities related to this upgrade will be at least 717 MVA for normal and emergency rating.

The estimated cost of the upgrade L30 is approximately $93.1 million. The Upgrade L30 is needed in 2030.

5.3 Import Paths

Due to the significant amounts of loads and lack of local conventional generation in the Permian Basin region, significant amounts of the regional transmission upgrades will be needed to transfer power to the Permian Basin region from across the ERCOT system.

Permian Basin region is located at the remote most western part of the ERCOT system. West Texas has significant renewable generation. Conventional generations are concentrated in the East, Coast, and central Texas near the load centers. Taking into account both the Permian Basin region need and the overall ERCOT system need, the following factors were considered in the design of the import paths:

- The import paths could import generation to the Permian Basin region to serve the forecasted Permian Basin load and also export excess renewable generation in West Texas to the load centers;
- Import from potential future generation areas to serve the Permian Basin region load;
- NERC CIP-014 impact consideration to avoid potential instability under the major 345-kV substation outages; and
- Overall cost effectiveness of the transmission upgrades.

Many location points mainly in the central Texas and South Texas were considered in the design of the import paths. Many candidate options were ruled out during the design process when we evaluated these consideration factors. As such, the transmission upgrades described in this section are ones that ERCOT proposed.

Both 345-kV and EHV (500-kV or 765-kV) import path options were evaluated in this study to transfer power across the ERCOT system.

5.3.1 345-kV Import Paths

Four new 345-kV double-circuit import paths plus a short path from Panhandle are needed to transfer power across the ERCOT system to serve the Permian Basin load in 2038. Two of the four 345-kV double-circuit import paths (subset of that in 2038 import paths) are needed in 2030. The total cost estimates of the 345-kV import paths are approximately $7.69 billion in 2038 and $3.99 billion in 2030. Below are the details of the 345-kV import paths and additional upgrades needed in 2030 and 2038.

Import Path 1:

- Construct a new 345-kV New Substation 2, about 2 miles southeast of the existing Comanche Peak Switch, cutting into the existing Comanche Peak Switch – Wolf Hollow/Mitchell Bend 345-kV double-circuit line and Comanche Peak Switch – Timberview/Johnson 345-kV double-circuit line. This upgrade is needed in 2030;
- Add a new New Substation 2 – Comanche Switch 345-kV double-circuit line with a normal and emergency rating of at least 2988 MVA per circuit. This will require approximately 58 miles of new ROW. This upgrade is needed in 2030;

- Add new New Substation 2 – Central Bluff – Longshore – Rockhound 345-kV double-circuit lines with a normal and emergency rating of at least 2988 MVA per circuit. This will require approximately 289 miles of new ROW. This upgrade is needed in 2038; and
- Add a new Moss – Border 345-kV double-circuit line with a normal and emergency rating of at least 2988 MVA per circuit. This will require approximately 82 miles of new ROW. This upgrade is needed in 2038.

The estimated cost of the Import Path 1 is approximately $1.83 billion and will require approximately 429 miles of new ROW.

Import Path 2:

- Add new Sam Switch – Comanche Switch – Twin Butte – King Mountain 345-kV double-circuit lines with a normal and emergency rating of at least 2988 MVA per circuit. This will require approximately 365 miles of new ROW.

The estimated cost of the Import Path 2 is approximately $1.45 billion and will require approximately 365 miles of new ROW. This upgrade is needed in 2030.

Import Path 3:

- Construct a new 345-kV New Substation 1, about 16 miles north of the existing Big Hill 345-kV substation, cutting into the existing Big Hill – Twin Butte 345-kV line;
- Construct a new 345-kV Lynx substation at the existing Lynx 138-kV substation, cutting into the existing Bakersfield – Solstice 345-kV double-circuit line; and
- Add new Bell East – Buckhorn – New Substation 1 – Nevil Road – Lynx 345-kV double-circuit lines with a normal and emergency rating of at least 2988 MVA per circuit. This will require approximately 374 miles of new ROW.

The estimated cost of the Import Path 3 is approximately $1.68 billion and will require approximately 374 miles of new ROW. This upgrade is needed in 2038.

Import Path 4:

- Construct a new 345-kV Hamilton substation at the existing Hamilton 138-kV substation. No 345/138-kV transformers were installed at Hamilton in this study. Add new dynamic reactive devices (350 MVAr) at Hamilton 345-kV substation; and
- Add new Fowlerton – Hamilton – Bottlebrush – Solstice 345-kV double-circuit lines with a normal and emergency rating of at least 2988 MVA per circuit. This will require approximately 393 miles of new ROW.

The estimated cost of the Import Path 4 is approximately $2.06 billion and will require approximately 393 miles of new ROW. This upgrade is needed in 2030.

Additional Upgrade 1:

- Bypass the series capacitors at Edison 345-kV substation and add new dynamic reactive devices (350 MVAr).

The estimated cost of the Additional Upgrade 1 is approximately $120 million. This upgrade is needed in 2030.

Additional Upgrade 2:

- Add a new White River – Long Draw 345-kV double-circuit line with a normal and emergency rating of at least 2988 MVA per circuit.

The estimated cost of the Additional Upgrade 2 is approximately $538.6 million and will require approximately 115 miles of new ROW. This upgrade is needed in 2038.

Among the four import paths described above, Import Paths 2 and 4 in addition to portion of the Import Path 1 will be needed in 2030. The new ROW is approximately 847 miles. Furthermore, additional dynamic reactive devices will be required to serve the 2030 Permian Basin region load. The total cost estimate of the 345-kV import paths is approximately $3.99 billion in 2030. Figure 5.6 shows the map of the 345-kV import paths together with the major 345-kV local transmission upgrades in 2030. The detailed map of the local transmission upgrades in the Permian Basin region needed in 2030 is shown in Figure 5.7.

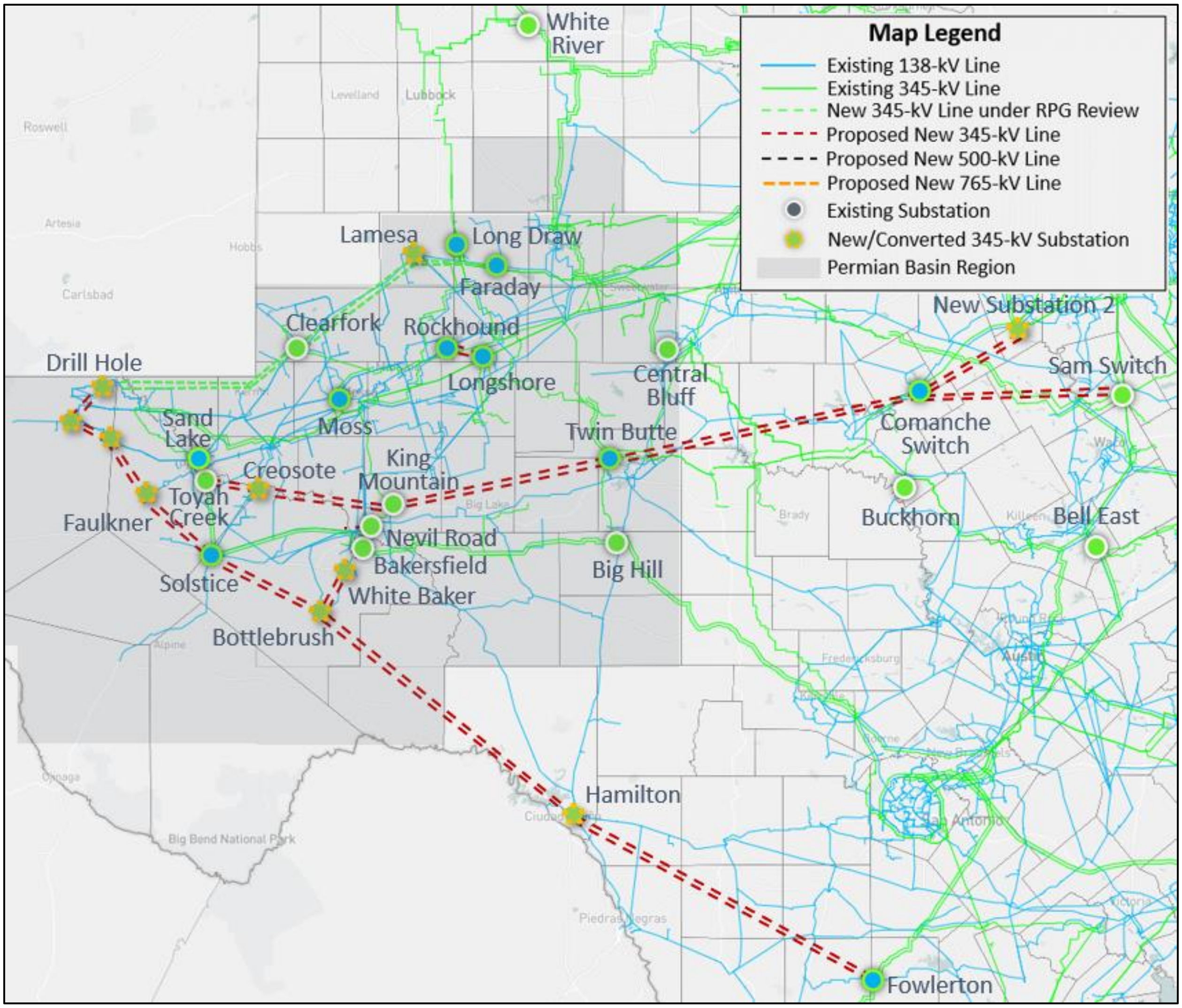

Figure 5.6: 345-kV Import Paths in 2030

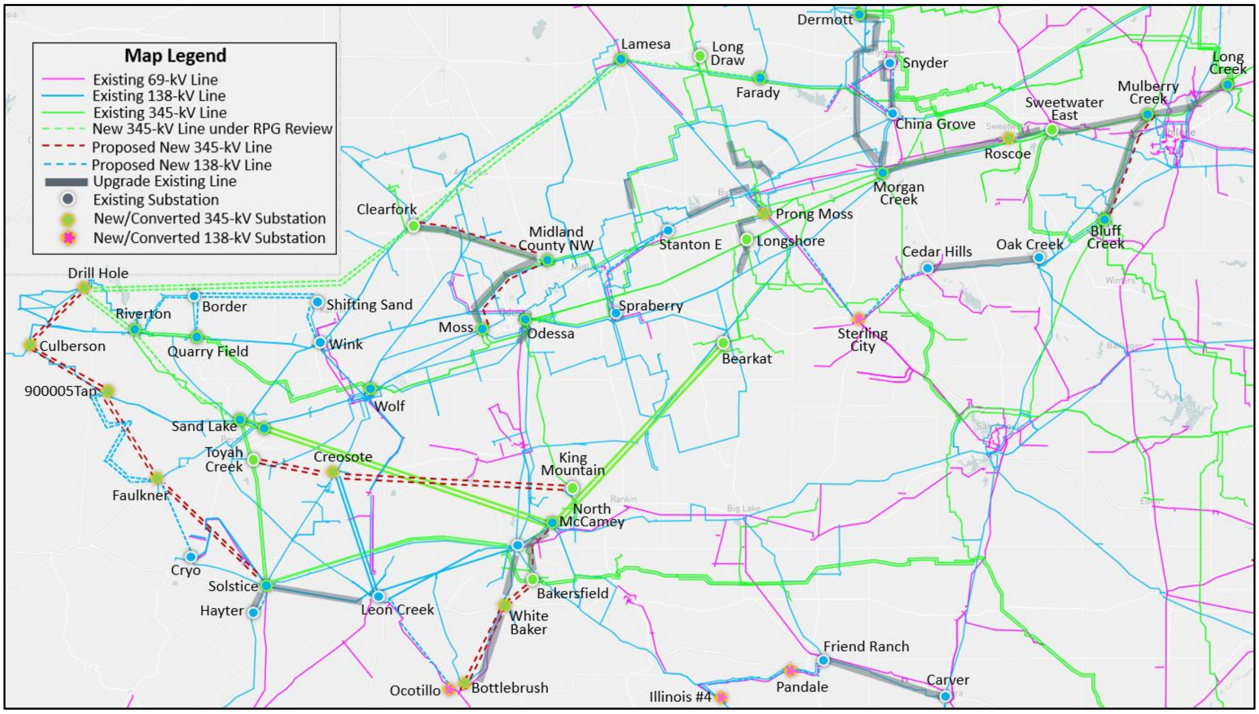

Figure 5.7: Local Transmission Upgrades in Permian Basin Region in 2030

All four new 345-kV double-circuit import paths plus a short path from the Panhandle (i.e., Additional Upgrade 2), approximately 1,676 miles of new ROW, and additional dynamic reactive devices will be required to serve the 2038 Permian Basin region load. The total cost estimate of the 345-kV import paths is approximately $7.69 billion in 2038. Figure 5.8 shows the map of the 345-kV import paths together with the major 345-kV local transmission upgrades in 2038. The detailed map of the local transmission upgrades in the Permian Basin region needed in the 345-kV import path option in 2038 is shown in Figure 5.9.

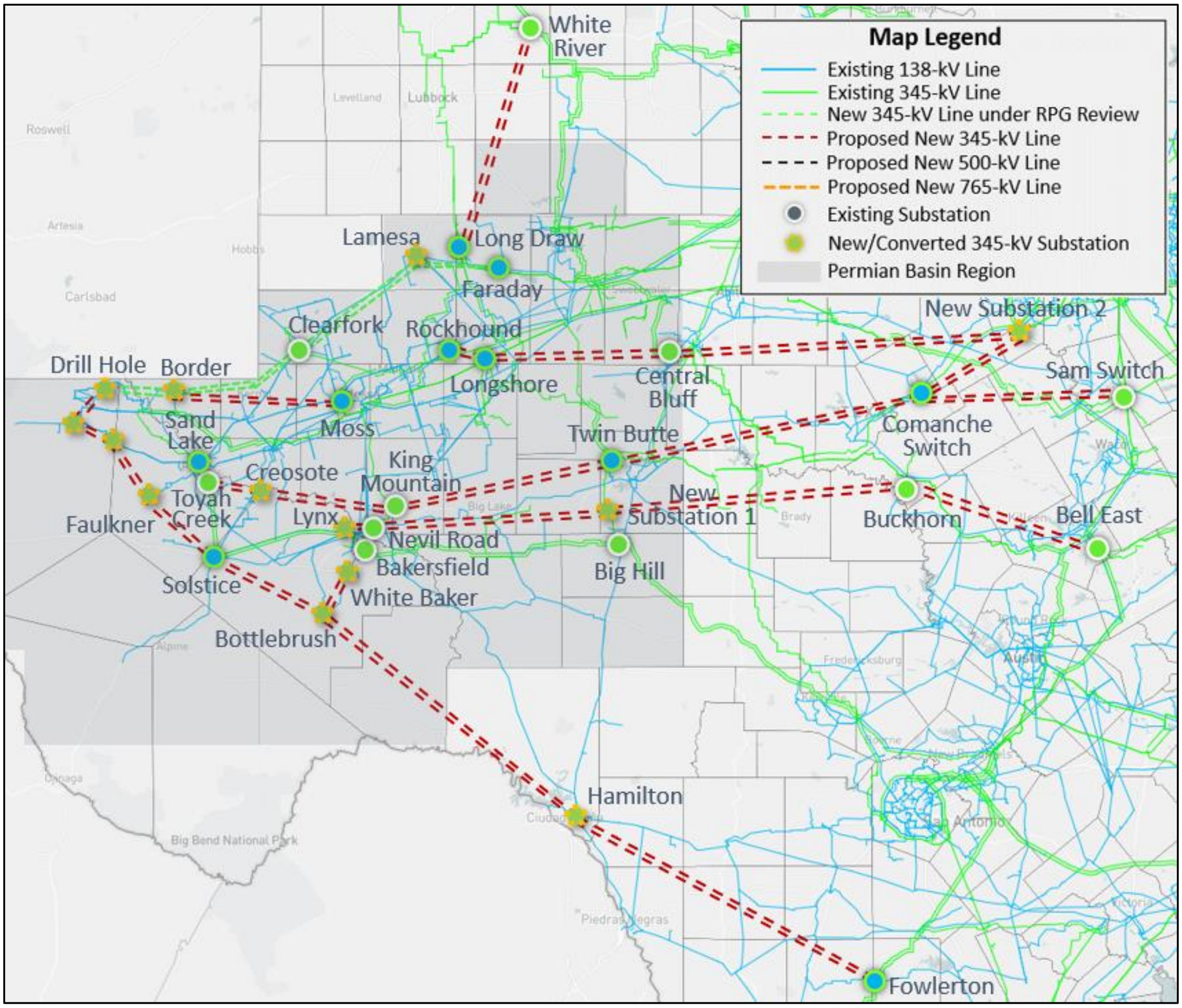

Figure 5.8: 345-kV Import Paths in 2038 (Includes Import Paths Needed in 2030)

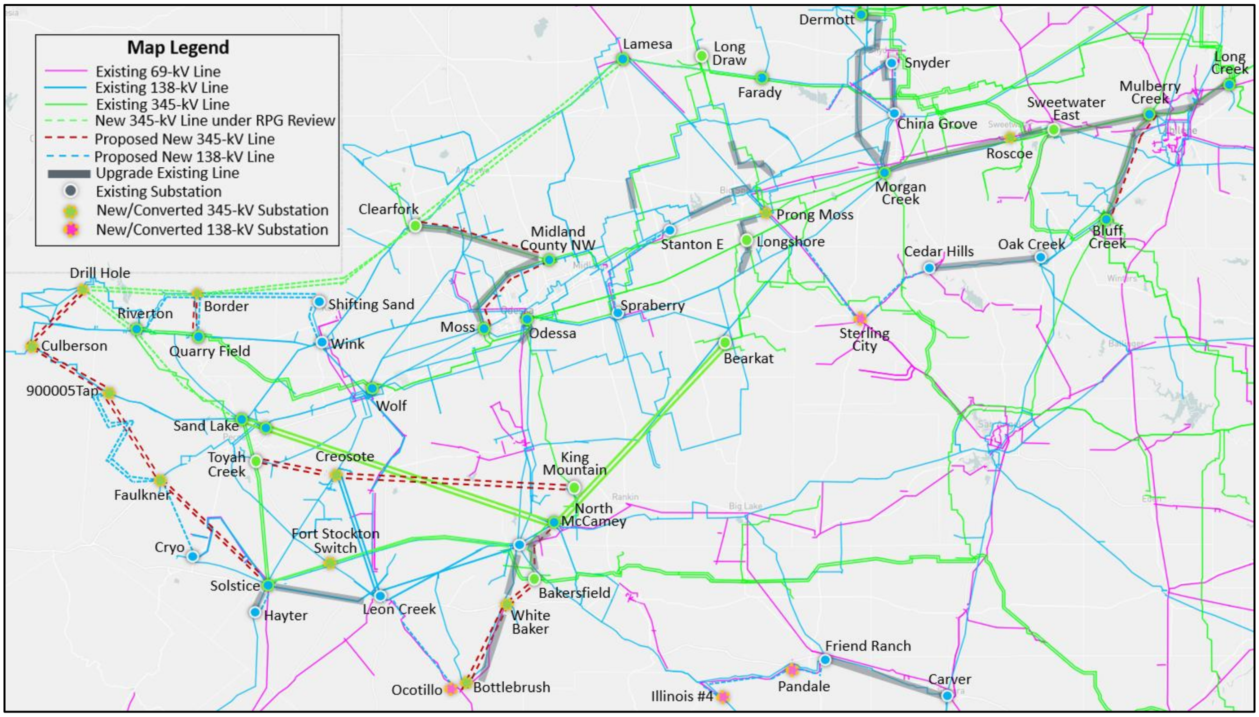

Figure 5.9: Local Transmission Upgrades in Permian Basin Region of 345-kV Import Path Option in 2038

5.3.2 500-kV Import Paths

The 500-kV import path option was evaluated for the 2038 Permian Basin region load level. Three new 500-kV double-circuit import paths (approximately 1,255 miles) plus a 345-kV short path from the Panhandle (approximately 115 miles), total approximately 1,370 miles of new lines, and additional dynamic reactive devices are needed to transfer power across the ERCOT system to serve the Permian Basin region load in 2038. The total cost estimate of the 500-kV import paths is approximately $10.61 billion. Below are the details of the 500-kV import path option and additional upgrades needed in 2038.

Import Path 1:

- Construct a new 500/345-kV New Substation 2, about 2 miles southeast of the existing Comanche Peak Switch and install four new 500/345-kV transformers with normal and emergency ratings of at least 1733 MVA and 1758 MVA. The New Substation 2 is cutting into the existing Comanche Peak Switch – Wolf Hollow/Mitchell Bend 345-kV double-circuit line and Comanche Peak Switch – Timberview/Johnson 345-kV double-circuit line;
- Construct a new Longshore 500/345-kV substation near the existing Longshore 345-kV substation and install four new 500/345-kV transformers with normal and emergency ratings of at least 1733 MVA and 1758 MVA;

- Construct a new Drill Hole 500/345-kV substation near the existing Drill Hole 138-kV substation and install four new 500/345-kV transformers with normal and emergency ratings of at least 1733 MVA and 1758 MVA;
- Add a new New Substation 2 – Longshore 500-kV double-circuit line with normal and emergency ratings of at least 3799 MVA and 5487 MVA per circuit. This will require approximately 257 miles of new ROW; and
- Add new Longshore – Drill Hole 500-kV double-circuit line with normal and emergency ratings of at least 3799 MVA and 5487 MVA per circuit. This will require approximately 185 miles of new ROW.

The estimated cost of the 500-kV Import Path 1 is approximately $3.58 billion and will require approximately 442 miles of new ROW.

Import Path 2:

- Construct a new Bell East 500/345-kV substation near the existing Bell East 345-kV substation and install four new 500/345-kV transformers with normal and emergency ratings of at least 1733 MVA and 1758 MVA;
- Construct a new Big Hill 500/345-kV substation near the existing Big Hill 345-kV substation and install four new 500/345-kV transformers with normal and emergency ratings of at least 1733 MVA and 1758 MVA;
- Construct a new Sand Lake 500/345-kV substation near the existing Sand Lake 345-kV substation and install four new 500/345-kV transformers with normal and emergency ratings of at least 1733 MVA and 1758 MVA;
- Add a new Bell East – Big Hill 500-kV double-circuit line with normal and emergency ratings of at least 3799 MVA and 5487 MVA per circuit. This will require approximately 233 miles of new ROW; and
- Add new Big Hill – Sand Lake 500-kV double-circuit line with normal and emergency ratings of at least 3799 MVA and 5487 MVA per circuit. This will require approximately 210 miles of new ROW.

The estimated cost of the 500-kV Import Path 2 is approximately $3.51 billion and will require approximately 443 miles of new ROW.

Import Path 3:

- Construct a new Howard 500/345-kV substation near the existing Howard 345-kV substation and install four new 500/345-kV transformers with normal and emergency ratings of at least 1733 MVA and 1758 MVA;
- Construct a new Solstice 500/345-kV substation near the existing Solstice 345-kV substation and install four new 500/345-kV transformers with normal and emergency ratings of at least 1733 MVA and 1758 MVA; and

- Add a new Howard – Solstice 500-kV double-circuit line with normal and emergency ratings of at least 3799 MVA and 5487 MVA per circuit. This will require approximately 370 miles of new ROW.

The estimated cost of the 500-kV Import Path 3 is approximately $2.86 billion and will require approximately 370 miles of new ROW.

Additional Upgrade 1:

- Bypass the series capacitors at Edison 345-kV substation and add new dynamic reactive devices (350 MVAr). The cost estimate of this upgrade is approximately $120 million.

Additional Upgrade 2:

- Add a new White River – Long Draw 345-kV double-circuit lines with a normal and emergency rating of at least 2988 MVA per circuit. This will require approximately 115 miles of new ROW. The cost estimate of this upgrade is approximately $538.6 million.

Figure 5.10 shows the map of the 500-kV import path together with the major 345-kV local transmission upgrades in 2038. The detailed map of the local transmission upgrades in the Permian Basin region needed in the 500-kV import paths option in 2038 is shown in Figure 5.11.

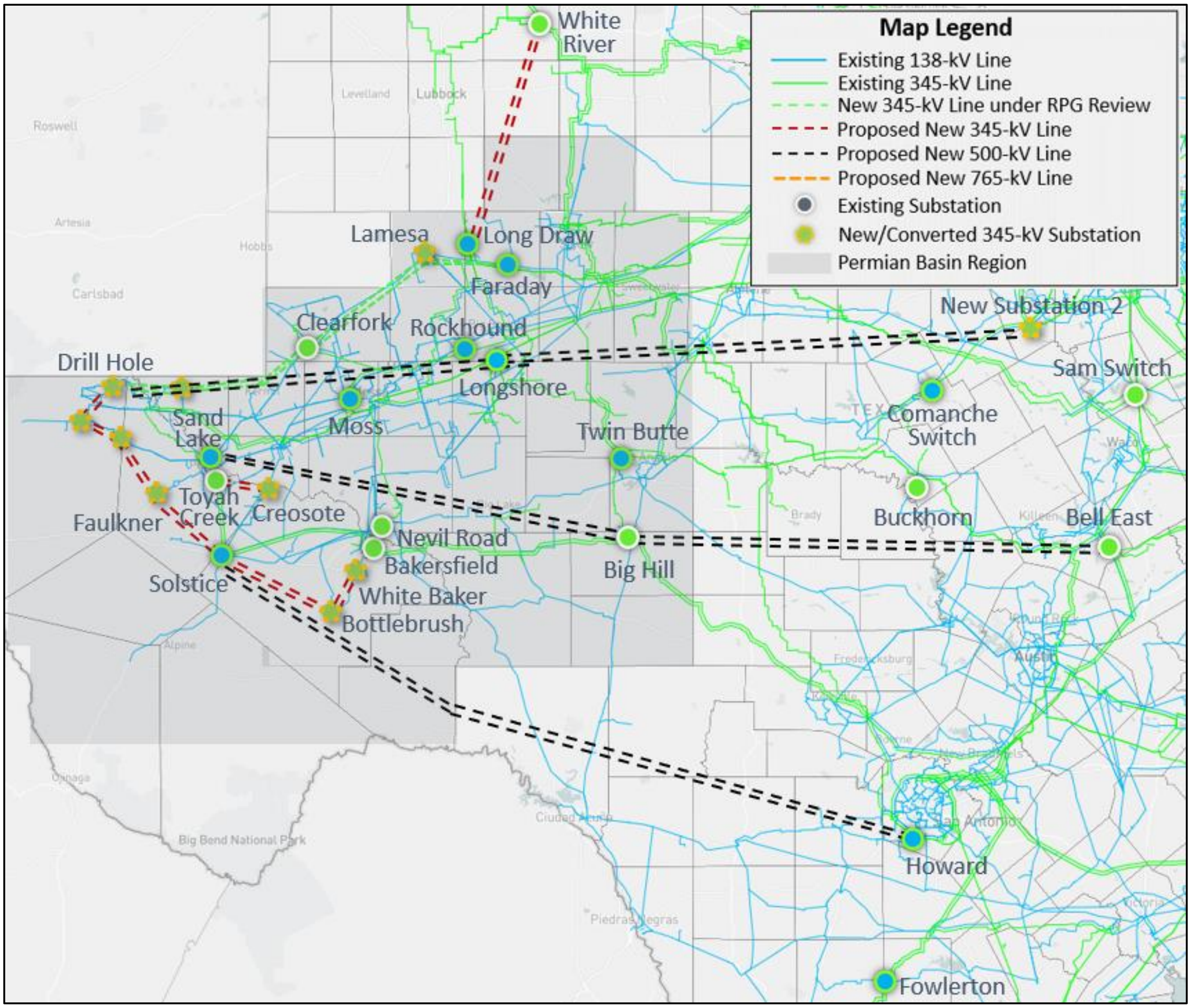

Figure 5.10: 500-kV Import Paths in 2038

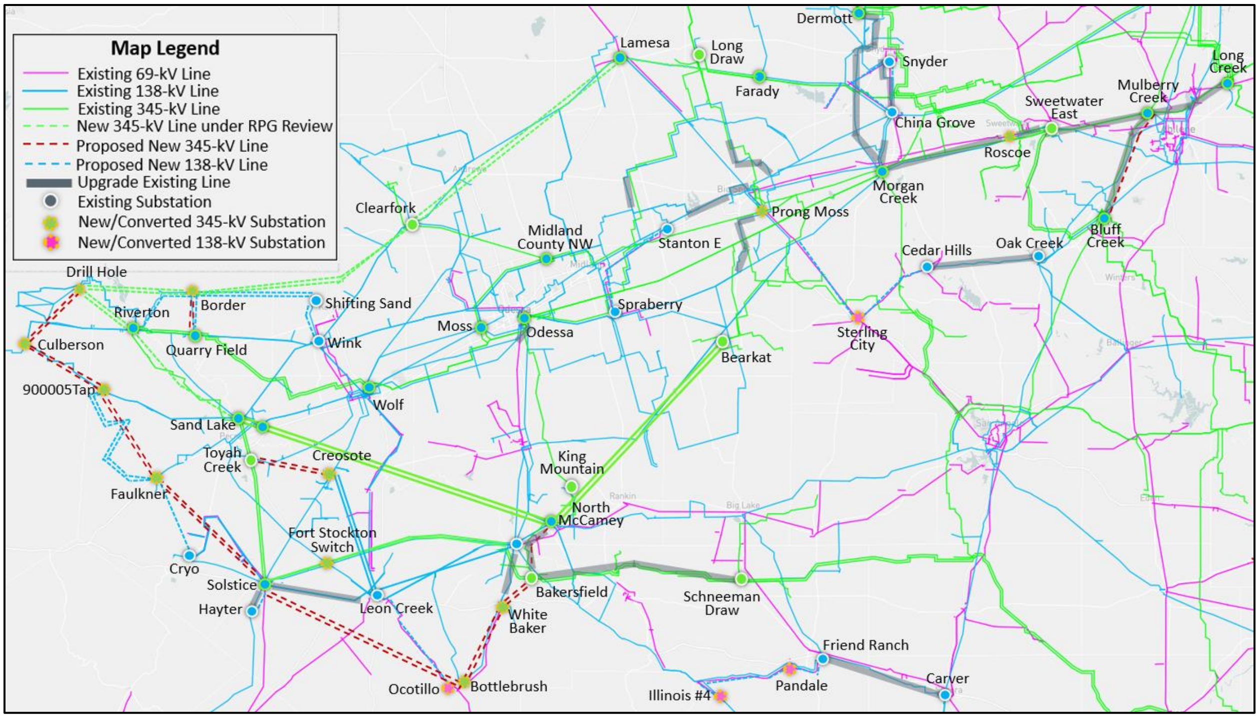

Figure 5.11: Local Transmission Upgrades in Permian Basin Region of 500-kV and 765-kV EHV Import Path Options in 2038

5.3.3 765-kV Import Paths

The 765-kV import path option was evaluated for the 2038 Permian Basin region load level. Three new 765-kV single-circuit import paths, approximately 1,255 miles, and additional dynamic reactive devices are needed to transfer power across the ERCOT system to serve the Permian Basin region load in 2038. The total cost estimate of the 765-kV import paths is approximately $9.06 billion. Below are the details of the 765-kV import paths and additional upgrades needed in 2038.

Import Path 1:

- Construct a new 765/345-kV New Substation 2, about 2 miles southeast of the existing Comanche Peak Switch and install two new 765/345-kV transformers with normal and emergency ratings of at least 2403 MVA and 2772 MVA. The New Substation 2 is cutting into the existing Comanche Peak Switch – Wolf Hollow/Mitchell Bend 345-kV double-circuit line and Comanche Peak Switch – Timberview/Johnson 345-kV double-circuit line;
- Construct a new Longshore 765/345-kV substation near the existing Longshore 345-kV substation and install two new 765/345-kV transformers with normal and emergency ratings of at least 2403 MVA and 2772 MVA;
- Construct a new Drill Hole 765/345-kV substation near the existing Drill Hole 138-kV substation and install two new 765/345-kV transformers with normal and emergency ratings of at least 2403 MVA and 2772 MVA;

- Add a new New Substation 2 – Longshore 765-kV single-circuit line with a normal and emergency rating of at least 7602 MVA per circuit. This will require approximately 257 miles of new ROW; and
- Add new Longshore – Drill Hole 765-kV single-circuit line with a normal and emergency rating of at least 7602 MVA per circuit. This will require approximately 185 miles of new ROW.

The estimated cost of the 765-kV Import Path 1 is approximately $3.22 billion and will require approximately 442 miles of new ROW.

Import Path 2:

- Construct a new Bell East 765/345-kV substation near the existing Bell East 345-kV substation and install two new 765/345-kV transformers with normal and emergency ratings of at least 2403 MVA and 2772 MVA;
- Construct a new Big Hill 765/345-kV substation near the existing Big Hill 345-kV substation and install two new 765/345-kV transformers with normal and emergency ratings of at least 2403 MVA and 2772 MVA;
- Construct a new Sand Lake 765/345-kV substation near the existing Sand Lake 345-kV substation and install two new 765/345-kV transformers with normal and emergency ratings of at least 2403 MVA and 2772 MVA;
- Add a new Bell East – Big Hill 765-kV single-circuit line with a normal and emergency rating of at least 7602 MVA per circuit. This will require approximately 233 miles of new ROW; and
- Add new Big Hill – Sand Lake 765-kV single-circuit line with a normal and emergency rating of at least 7602 MVA per circuit. This will require approximately 210 miles of new ROW.

The estimated cost of the 765-kV Import Path 2 is approximately $3.16 billion and will require approximately 443 miles of new ROW.

Import Path 3:

- Construct a new Howard 765/345-kV substation near the existing Howard 345-kV substation and install two new 765/345-kV transformers with normal and emergency ratings of at least 2403 MVA and 2772 MVA;
- Construct a new Solstice 765/345-kV substation near the existing Solstice 345-kV substation and install two new 765/345-kV transformers with normal and emergency ratings of at least 2403 MVA and 2772 MVA; and
- Add a new Howard – Solstice 765-kV single-circuit line with a normal and emergency rating of at least 7602 MVA per circuit. This will require approximately 370 miles of new ROW.

The estimated cost of the 765-kV Import Path 3 is approximately $2.56 billion and will require approximately 370 miles of new ROW.

Additional Upgrade 1:

- Bypass the series capacitors at Edison 345-kV substation and add new dynamic reactive devices (350 MVAr). The cost estimate of this upgrade is approximately $120 million.

Figure 5.12 shows the map of the 765-kV import paths together with the major 345-kV local transmission upgrades in 2038. The detailed map of the local transmission upgrades in the Permian Basin region needed in the 765-kV import path option in 2038 is the same as in the 500-kV import path option shown in Figure 5.11.

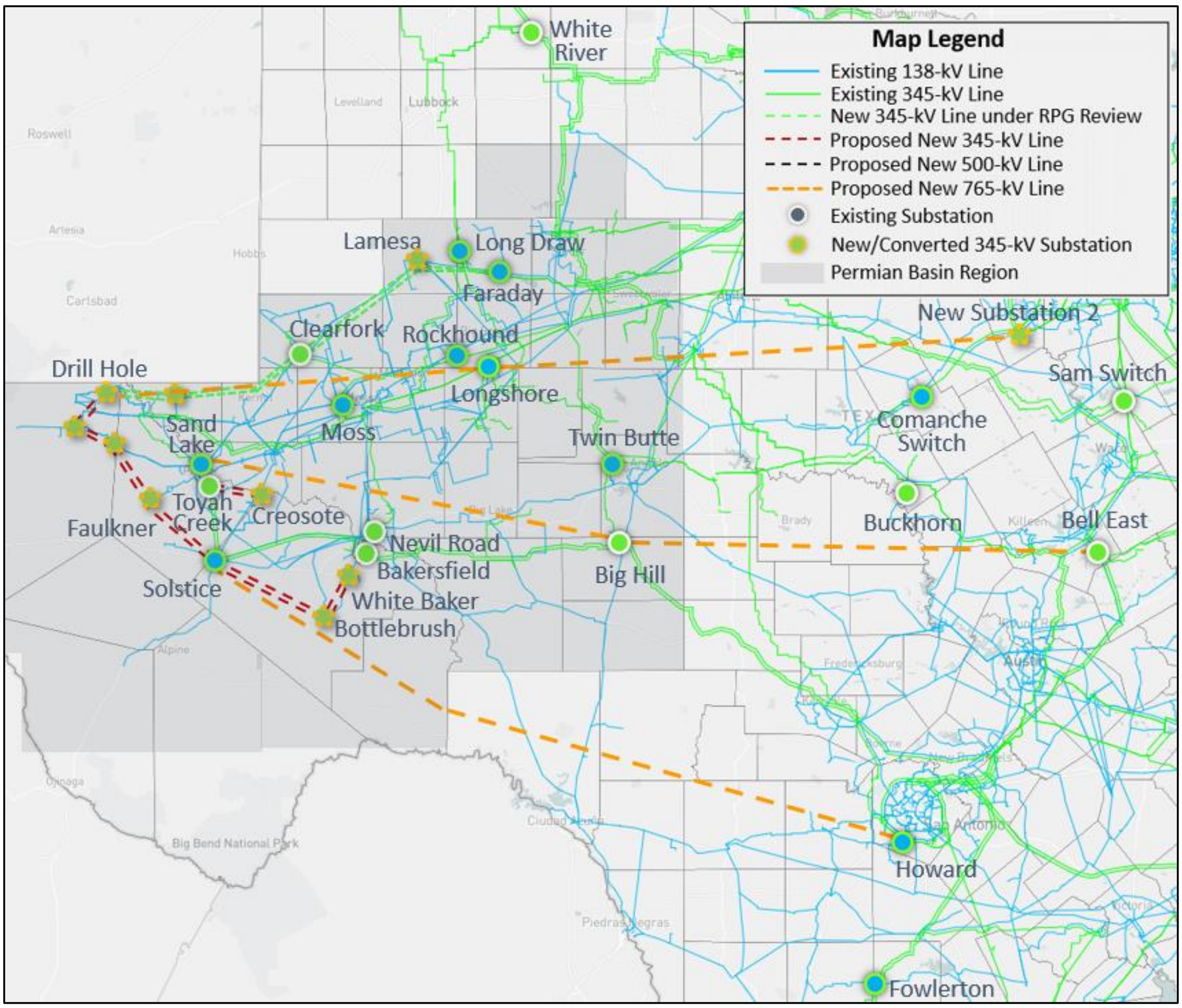

Figure 5.12: 765-kV Import Paths in 2038

6 Dynamic Stability Analysis

Dynamic stability analysis examines a power system's behavior before, during, and after a disturbance such as a fault on a transmission line. It involves assessing the system's ability to maintain stability, withstand the disturbance, and return to a steady-state condition. The analysis ensures that the system can handle faults without losing synchronism or experiencing unacceptable oscillations, ensuring reliable and continuous operation.

As detailed in Section 2.5.1, ERCOT performed a dynamic stability analysis focused exclusively on the P1 and P7 contingencies in the study area, as these are the most probable to occur. The limited dynamic stability analyses were performed for the case with the 345-kV import path option, and the case with 765-kV import path option, as described in Section 2:

1) utilizing the 2038 case with the 345-kV import paths identified in Section 5.3.1
2) utilizing the 2038 case with the 765-kV import paths identified in Section 5.3.3

For the 345-kV import path option or the 765-kV import path option, the results demonstrated that there are no planning criteria violations pertaining to transient stability as specified in the criteria described in Section 2.5.1. Example plots demonstrating that performance criteria are met can be found in Appendix A.2.

7 Summary of the Transmission Upgrades

ERCOT identified and recommends significant transmission upgrades to address the reliability needs in the Permian Basin region based on the study assumptions. The transmission upgrades include local transmission upgrades to connect and reliably serve the loads and additional import paths to transfer power to the Permian Basin region across the ERCOT system. ERCOT evaluated 345-kV, 500-kV, and 765-kV import path options in this study. 500-kV and 765-kV options were evaluated for 2038. Table 7.1 lists the details of the common local transmission upgrades needed in 2030 and 2038 under all import path options. Tables 7.2 - 7.5 summarize the import paths and the associated incremental local transmission upgrades in 2030 and 2038.

Table 7.1: Common Local Transmission Upgrades Needed in 2030 and 2038

Project ID	Proposed Transmission Upgrades (Note: Assumed ratings can be found in Section 5)	Year of Study Case with Reliability Need Starting to Appear	Approximate Cost Estimate ($M)
L1	Add Quarry Field – Border 138-kV second circuit	2030	136.0
L1	Add Wink – Shifting Sands 138-kV second circuit	2030	
L1	Connect new load bus 900004 to Border and new load bus 900066 to Shifting Sands to form a 138-kV double-circuit loop	2030	
L1	Add Riverton – Border 138-kV second circuit	2030	

Project ID	Proposed Transmission Upgrades (Note: Assumed ratings can be found in Section 5)	Year of Study Case with Reliability Need Starting to Appear	Approximate Cost Estimate ($M)
L3	Connect new load buses to 11610 and Faulkner and form a 138-kV double-circuit loop: 11610 – 900005 – 900111 – 900023 – 900012 – 900021 – 900038 – 38124	2030	120.8
L4	Connect new load bus 900108 to Faulkner and Cryo to form a 138-kV single-circuit loop	2030	44.9
L5	Establish a new Culberson 345/138-kV substation at the existing Culberson Switch and install two new 345/138-kV transformers	2030	725.3
L5	Establish a new ONC900005_TAP 345/138-kV substation and install two new 345/138-kV transformers	2030	
L5	Establish a new Faulkner 345/138-kV substation at Faulkner station and install two new 345/138-kV transformers	2030	
L5	Add a new Drill Hole – Culberson 345-kV double-circuit line	2030	
L5	Add a new Culberson – 900005Tap 345-kV double-circuit line	2030	
L5	Add a new 900005Tap – Faulkner 345-kV double-circuit line	2030	
L5	Add a new Solstice – Faulkner 345-kV double-circuit line	2030	
L7	Establish a new Creosote 345/138-kV substation and install three new 345/138-kV transformers	2030	235.7
L7	Add a new Creosote – Toyah Creek 345-kV double-circuit line	2030	
L8	Upgrade the existing Creosote – Trans Pecos Tap 138-kV line	2030	0.0
L10	Bypass the Solstice phase shifting transformer and upgrade the existing Solstice – FT Stockton Plant 138-kV line	2030	44.6
L11	Rebuild the existing Solstice – Hayter Tap 138-kV line to double-circuit; Move the large load as well as LCRA load at Hayter Tap to Hayter and radially serve the loads at Hayter from Solstice	2030	10.5
L12	Convert the existing 16th Street – FT Stockton – Pinion – Ocotillo 69-kV line to 138kV	2030	87.9
L12	Tie Ocotillo 138-kV substation to Bottlebrush 138-kV substation	2030	
L12	Expand Ocotillo substation and move the 16th Street 138/69-kV transformer to Ocotillo	2030	
L12	Upgrade the existing 16th Street – Alamo Street 138-kV line	2030	
L13	Establish a new White Baker 345/138-kV substation at the existing White Baker 138-kV station and install two new 345/138-kV transformers	2030	323.8
L13	Establish a new Bottlebrush345/138-kV substation near the existing Century 138-kV station and install two new 345/138-kV transformers	2030	
L13	Add a new Bakersfield – White Baker 345-kV double-circuit line	2030	
L13	Add a new White Baker – Bottlebrush 345-kV double-circuit line	2030	
L13	Upgrade the existing White Baker – Girvin 138-kV line	2030	
L13	Terminal equipment upgrade of White Baker – Sherbino II Wind Farm 138-kV line	2030	
L14	Upgrade the existing Bakersfield – Nevill Road 345-kV line and add a second circuit	2030	119.6
L14	Upgrade the existing Nevill Road – North McCamey 345-kV line and add a second circuit	2030	
L17	Upgrade Odessa – Reiter 138kV double-circuit line	2030	13.0

Project ID	Proposed Transmission Upgrades (Note: Assumed ratings can be found in Section 5)	Year of Study Case with Reliability Need Starting to Appear	Approximate Cost Estimate ($M)
L18	Convert the existing Stanton East – Midland Basin – Spraberry 69-kV line to 138-kV	2030	92.0
L19	Upgrade the existing Grady – Coronado Midstream Tap – Sales Ranch 138-kV line	2030	22.0
L20	Establish a new Prong Moss 345/138-kV substation and install two new 345/138-kV transformers	2030	249.0
L20	Loop the existing Elbow – Bulldog 138-kV line into Prong Moss	2030	
L20	Upgrade the existing Elbow – Prong Moss 138-kV line	2030	
L20	Loop the existing Hill Crest – McDonald Road 138-kV line into Prong Moss	2030	
L20	Convert the existing Big Spring – Signal Mountain 69-kV line to 138-kV	2030	
L20	Connect Signal Mountain to Prong Moss	2030	
L20	Construct a new Chalk 138-kV substation and loop the existing McDonald Road – Navigation 138-kV line into Chalk	2030	
L20	Upgrade the existing Eiland – Elbow 138-kV line	2030	
L20	Upgrade the existing Luther – Bulldog 138-kV line	2030	
L21	Upgrade the existing Natural Dam – Beals Creek 138-kV line	2030	41.0
L21	Upgrade the existing Big Springs – Steer 138-kV line	2030	
L22	Add a new Ranger – Frontier 138-kV line (second 138-kV line)	2030	173.0
L22	Upgrade the existing Ranger – Sun 138-kV line	2030	
L22	Upgrade the existing Sun – Golden Switch – Dermott 138-kV line	2030	
L22	Upgrade the existing Sun – Sacroc 138-kV line	2030	
L22	Upgrade the existing Deep Creek – China Grove 138-kV line	2030	
L22	Upgrade the existing China Grove – 900126 138-kV line	2030	
L23	Convert the existing Snyder – Scurry – China Grove and Snyder – Amoco Tap – China Grove 69-kV lines to 138-kV	2030	196.0
L24	Upgrade the existing Cattleman – Champion Creek/Bitter Creek – Sweetwater East 345-kV double-circuit line	2030	607.9
L24	Upgrade the existing Long Creek – Sweetwater East 345-kV double-circuit line	2030	
L25	Establish a new Roscoe 345/138-kV substation near the Sweetwater Tap (1341) and install two new 345/138-kV transformers	2030	143.0
L25	Loop the existing Sweetwater East – Champion Creek/Bitter Creek – Cattleman 345-kV double-circuit line into Roscoe	2030	
L25	Convert the existing Plowboy – Eskota 69-kV line to 138-kV	2030	
L25	Loop the converted Plowboy – Eskota 138-kV line into Roscoe near the Sweetwater	2030	
L25	Move the Eskota 138/69-kV transformer 1 to Plowboy	2030	
L26	Upgrade the existing Bluff Creek – Abilene Mulberry Creek 345-kV line and add a second circuit	2030	136.9
L27	Convert the existing Cedar Hill – Sterling City – Kinnebrew Poi – Chalk 69-kV line to 138-kV	2030	226.4
L27	Upgrade the existing Oak Creek – Cedar Hills 138-kV line	2030	
L28	Connect 900052 to Big Lake to form a 138-kV loop	2030	22.5
L29	Upgrade the existing Friend Ranch – Carver 138-kV line	2030	60.1

Project ID	Proposed Transmission Upgrades (Note: Assumed ratings can be found in Section 5)	Year of Study Case with Reliability Need Starting to Appear	Approximate Cost Estimate ($M)
L30	Convert the existing Illinois #4 – Pandale – Ozona – Friend Ranch 69-kV line to 138-kV, and expand Ozona substation and move the Illinois #4 138/69-kV transformer to Ozona	2030	93.1
L30	Expand the Pandale substation and build a new 138-kV tie between Pandale and Stockman substation	2030	

Table 7.2: 2030 345-kV Import Paths and Associated Incremental Local Transmission Upgrades

Project ID	Proposed Transmission Upgrades (Note: Assumed ratings can be found in Section 5)	Year of Study Case with Reliability Need Starting to Appear	Approximate Cost Estimate ($M)
Import 1	Construct a new 345-kV New Substation 2, about 2 miles southeast of the existing Comanche Peak Switch, cutting into the existing Comanche Peak – Wolf Hollow/Mitchell Bend 345-kV double-circuit line and Comanche Peak – Timberview/Johnson 345-kV double-circuit line	2030	360.0
Import 1	Add a new New Substation 2 – Comanche Switch 345-kV double-circuit line	2030	
Import 2	Add a new Sam Switch – Comanche Switch 345-kV double-circuit line	2030	1,447.7
Import 2	Add a new Comanche Switch – Twin Butte 345-kV double-circuit line	2030	
Import 2	Add a new Twin Butte – King Mountain 345-kV double-circuit line	2030	
Import 4	Establish a new Hamilton 345-kV substation at the existing Hamilton 138-kV substation	2030	2,062.9
Import 4	Add a new Fowlerton – Hamilton 345-kV double-circuit line	2030	
Import 4	Add a new Hamilton – Bottlebrush 345-kV double-circuit line	2030	
Import 4	Add a new Bottlebrush – Solstice 345-kV double-circuit line	2030	
Import 4	Add dynamic reactive devices (e.g., Synchronous Condenser) at Hamilton	2030	
Import A1	Bypass the series capacitors at Edison and add dynamic reactive devices (e.g., Synchronous Condenser) at Edison	2030	120.0
L7	Add a new King Mountain – Creosote 345-kV double-circuit line	2030	340.0
L13	Upgrade the existing White Baker – Bottlebrush 138-kV line	2030	41.8
L16	Upgrade the existing Moss – Midland County NW 345-kV line and add a second circuit	2030	649.0
L16	Upgrade the existing Gardendale – Clearfork 345-kV line and add a second circuit	2030	
L16	Upgrade the existing Gardendale – Telephone Road 345-kV line and add a second circuit	2030	

Table 7.3: 2038 345-kV Import Paths (including the 2030 345-kV Import Paths) and Associated Incremental Local Transmission Upgrades

Project ID	Proposed Transmission Upgrades (Note: Assumed ratings can be found in Section 5)	Year of Study Case with Reliability Need Starting to Appear	Approximate Cost Estimate ($M)
Import 1	Construct a new 345-kV New Substation 2, about 2 miles southeast of the existing Comanche Peak Switch, cutting into the existing Comanche Peak – Wolf Hollow/Mitchell Bend 345-kV double-circuit line and Comanche Peak – Timberview/Johnson 345-kV double-circuit line	2030	1,832.0
Import 1	Add a new New Substation 2 – Comanche Switch 345-kV double-circuit line	2030	
Import 1	Add a new New Substation 2 – Central Bluff 345-kV double-circuit line	2038	
Import 1	Add a new Central Bluff – Longshore 345-kV double-circuit line	2038	
Import 1	Add a new Longshore – Rockhound 345-kV double-circuit line	2038	
Import 1	Add a new Moss – Border 345-kV double-circuit line	2038	
Import 2	Add a new Sam Switch – Comanche Switch 345-kV double-circuit line	2030	1,447.7
Import 2	Add a new Comanche Switch – Twin Butte 345-kV double-circuit line	2030	
Import 2	Add a new Twin Butte – King Mountain 345-kV double-circuit line	2030	
Import 3	Add a new Bell East – Buckhorn 345-kV double-circuit line	2038	1,679.7
Import 3	Establish a new New Substation 1 345-kV substation cutting into the existing Big Hill – Twin Butte 345-kV line, about 16 miles away from Big Hill	2038	
Import 3	Add a new Buckhorn – New Substation 1 345-kV double-circuit line	2038	
Import 3	Add a new New Substation 1 – Nevil Road 345-kV double-circuit line	2038	
Import 3	Establish a new Lynx 345-kV Station at the existing Lynx station	2038	
Import 3	Add a new Nevil Road – Lynx 345-kV double-circuit line	2038	
Import 4	Establish a new Hamilton 345-kV substation at the existing Hamilton 138-kV substation	2030	2,062.9
Import 4	Add a new Fowlerton – Hamilton 345-kV double-circuit line	2030	
Import 4	Add a new Hamilton – Bottlebrush 345-kV double-circuit line	2030	
Import 4	Add a new Bottlebrush – Solstice 345-kV double-circuit line	2030	
Import 4	Add dynamic reactive devices (e.g., Synchronous Condenser) at Hamilton	2030	
Import A1	Bypass the series capacitors at Edison and add dynamic reactive devices (e.g., Synchronous Condenser) at Edison	2030	120.0
Import A2	Add a new White River – Long Draw 345-kV double-circuit line	2038	538.6
L2	Establish a new Border 345/138-kV substation and install two new 345/138-kV transformers	2038	95.0
L2	Loop the Stage 5 upgrade of new Clearfork – Drill Hole 345-kV double-circuit line into the new Border 345-kV substation	2038	
L2	Add a new Border – Quarry Field 345-kV double-circuit line	2038	
L6	Upgrade the existing Cowpen – Birds of Pray Tap 138-kV line	2038	2.0
L7	Add a new King Mountain – Creosote 345-kV double-circuit line	2030	340.0
L9	Establish a new FT Stockton Switch 345/138-kV substation at the existing FT Stockton Switch and install three new 345/138-kV transformers	2038	104.1
L9	Loop the existing Solstice – Bakersfield 345-kV double-circuit line into the new FT Stockton Switch 345-kV substation	2038	
L13	Upgrade the existing White Baker – Bottlebrush 138-kV line	2030	41.8

Project ID	Proposed Transmission Upgrades (Note: Assumed ratings can be found in Section 5)	Year of Study Case with Reliability Need Starting to Appear	Approximate Cost Estimate ($M)
L16	Upgrade the existing Moss – Midland County NW 345-kV line and add a second circuit	2030	649.0
L16	Upgrade the existing Gardendale – Clearfork 345-kV line and add a second circuit	2030	
L16	Upgrade the existing Gardendale – Telephone Road 345-kV line and add a second circuit	2030	

Table 7.4: 500-kV Import Paths and Associated Incremental Local Transmission Upgrades

Project ID	Proposed Transmission Upgrades (Note: Assumed ratings can be found in Section 5)	Year of Study Case with Reliability Need Starting to Appear	Approximate Cost Estimate ($M)
Import 1	Construct a new 500/345-kV New Substation 2, about 2 miles southeast of the existing Comanche Peak Switch and install four new 500/345-kV transformers. The New Substation 2 is cutting into the existing Comanche Peak – Wolf Hollow/Mitchell Bend 345-kV double-circuit line and Comanche Peak – Timberview/Johnson 345-kV double-circuit line	2038	3,577.3
Import 1	Construct a new 500/345-kV Longshore substation near the existing Longshore substation and install four new 500/345-kV transformers	2038	
Import 1	Construct a new 500/345-kV Drill Hole substation near the existing Drill Hole substation and install four new 500/345-kV transformers	2038	
Import 1	Add a new New Substation 2 – Longshore 500-kV double-circuit line	2038	
Import 1	Add a new Longshore – Drill Hole 500-kV double-circuit line	2038	
Import 2	Construct a new 500/345-kV East Bell substation near the existing East Bell substation and install four new 500/345-kV transformers	2038	3,514.2
Import 2	Construct a new 500/345-kV Big Hill substation near the existing Big Hill substation and install four new 500/345-kV transformers	2038	
Import 2	Construct a new 500/345-kV Sand Lake substation near the existing Sand Lake substation and install four new 500/345-kV transformers	2038	
Import 2	Add a new Bell East – Big Hill 500-kV double-circuit line	2038	
Import 2	Add a new Big Hill – Sand Lake 500-kV double-circuit line	2038	
Import 3	Construct a new 500/345-kV Howard substation near the existing Howard substation and install four new 500/345-kV transformers	2038	2,855.0
Import 3	Construct a new 500/345-kV Solstice substation near the existing Solstice substation and install four new 500/345-kV transformers	2038	
Import 3	Add a new Howard – Solstice 500-kV double-circuit line	2038	
Import A1	Bypass the series capacitors at Edison and add dynamic reactive devices (e.g., Synchronous Condenser) at Edison	2030	120.0
Import A2	Add a new White River – Long Draw 345-kV double-circuit line	2038	538.6
L31*	Add a new Bottlebrush – Solstice 345-kV double-circuit line	2030	297.0
L2	Establish a new Border 345/138-kV substation and install two new 345/138-kV transformers	2038	95.0
L2	Loop the Stage 5 upgrade of new Clearfork – Drill Hole 345-kV double-circuit line into the new Border 345-kV substation	2038	

Project ID	Proposed Transmission Upgrades (Note: Assumed ratings can be found in Section 5)	Year of Study Case with Reliability Need Starting to Appear	Approximate Cost Estimate ($M)
L2	Add a new Border – Quarry Field 345-kV double-circuit line	2038	
L9	Establish a new FT Stockton Switch 345/138-kV substation at the existing FT Stockton Switch and install three new 345/138-kV transformers	2038	104.1
L9	Loop the existing Solstice – Bakersfield 345-kV double-circuit line into the new FT Stockton Switch 345-kV substation	2038	
L15	Upgrade the existing Bakersfield – Cedar Caynon – Noelke – Schneeman Draw 345-kV double-circuit line	2038	192.7

* The project L31 is part of the 345-kV import path 4 in Table 7.3.

Table 7.5: 765-kV Import Paths and Associated Incremental Local Transmission Upgrades

Project ID	Proposed Transmission Upgrades (Note: Assumed ratings can be found in Section 5)	Year of Study Case with Reliability Need Starting to Appear	Approximate Cost Estimate ($M)
Import 1	Construct a new 765/345-kV New Substation 2, about 2 miles southeast of the existing Comanche Peak Switch and install two new 765/345-kV transformers. The New Substation 2 is cutting into the existing Comanche Peak – Wolf Hollow/Mitchell Bend 345-kV double-circuit line and Comanche Peak – Timberview/Johnson 345-kV double-circuit line	2038	3,221.3
Import 1	Construct a new 765/345-kV Longshore substation near the existing Longshore substation and install two new 765/345-kV transformers	2038	
Import 1	Construct a new 765/345-kV Drill Hole substation near the existing Drill Hole substation and install two new 765/345-kV transformers	2038	
Import 1	Add a new New Substation 2 – Longshore 765-kV single -circuit line	2038	
Import 1	Add a new Longshore – Drill Hole 765-kV single -circuit line	2038	
Import 2	Construct a new 765/345-kV East Bell substation near the existing East Bell substation and install two new 765/345-kV transformers	2038	3,157.4
Import 2	Construct a new 765/345-kV Big Hill substation near the existing Big Hill substation and install two new 765/345-kV transformers	2038	
Import 2	Construct a new 765/345-kV Sand Lake substation near the existing Sand Lake substation and install two new 765/345-kV transformers	2038	
Import 2	Add a new Bell East – Big Hill 765-kV single -circuit line	2038	
Import 2	Add a new Big Hill – Sand Lake 765-kV single -circuit line	2038	
Import 3	Construct a new 765/345-kV Howard substation near the existing Howard substation and install two new 765/345-kV transformers	2038	2,560.4
Import 3	Construct a new 765/345-kV Solstice substation near the existing Solstice substation and install two new 765/345-kV transformers	2038	
Import 3	Add a new Howard – Solstice 765-kV single-circuit line	2038	
Import A1	Bypass the series capacitors at Edison and add dynamic reactive devices (e.g., Synchronous Condenser) at Edison	2030	120.0
L31*	Add a new Bottlebrush – Solstice 345-kV double-circuit line	2030	297.0
L2	Establish a new Border 345/138-kV substation and install two new 345/138-kV transformers	2038	95.0

Project ID	Proposed Transmission Upgrades (Note: Assumed ratings can be found in Section 5)	Year of Study Case with Reliability Need Starting to Appear	Approximate Cost Estimate ($M)
L2	Loop the Stage 5 upgrade of new Clearfork – Drill Hole 345-kV double-circuit line into the new Border 345-kV substation	2038	
L2	Add a new Border – Quarry Field 345-kV double-circuit line	2038	
L9	Establish a new FT Stockton Switch 345/138-kV substation at the existing FT Stockton Switch and install three new 345/138-kV transformers	2038	104.1
L9	Loop the existing Solstice – Bakersfield 345-kV double-circuit line into the new FT Stockton Switch 345-kV substation	2038	
L15	Upgrade the existing Bakersfield – Cedar Caynon – Noelke – Schneeman Draw 345-kV double-circuit line	2038	192.7

* The project L31 is part of the 345-kV import path 4 in Table 7.3.

Majority of the local transmission upgrades identified for 2038 are needed in 2030. And majority of the local transmission upgrades are common among different import path options in 2038. The total cost estimate for the common local transmission upgrades needed (2030 or 2038) is approximately $4.02 billion.

The total cost estimate for local upgrades and the 345-kV import path option in 2030 is a subset, approximately $9.04 billion, of the total 2038 cost estimate of approximately $12.95 billion. The total cost estimate for local upgrades and the 500-kV import paths in 2038 is approximately $15.32 billion. The total cost estimate for local upgrades and the 765-kV import paths in 2038 is approximately $13.77 billion. For the EHV import path options (500-kV or 765-kV), a small subset of the local transmission upgrades (estimated cost of approximately $0.54 billion) would not be needed.

Table 7.6 summarizes the comparison for the 345-kV import path option and EHV (500-kV or 765-kV) import path options in 2038.

Table 7.6: Import Paths Comparison of 345-kV and EHV Options in 2038

	345-kV	500-kV	765-kV
Meets ERCOT and NERC Reliability Criteria	Yes	Yes	Yes
Incremental Transfer Capability* (MW)	1,340	1,712	2,105
Improves Operational Flexibility	Yes	Yes	Yes
Transmission Losses under System Peak Condition	3.0%	2.8%	2.7%
Number of Import Paths Required	5	4	3
New ROW** Required for Import Paths (miles)	1,676	1,370	1,255
Average Transmission Line Cost*** ($Million/mile)	4.04	6.86	6.10
Total Cost Estimate ($Billion)	12.95	15.32	13.77

* Incremental transfer capability under N-1 contingency conditions.

** A routing adder of 20% to the straight distance between two end points was assumed.

*** For 345-kV import path option, the average cost based on the TSPs cost estimates for 345-kV import paths was used. MISO 2024 Transmission Cost Estimation Guide was referenced for the EHV options (500-kV or 765-kV).

8 Other Considerations of Import Paths

ERCOT has received significant load growth projection for the entire ERCOT grid in addition to the Permian Basin region load growth studied in this report. The load projection for near-term planning horizon in 2030 summer peak is approximately 155 GW which includes approximately 59 GW of additional demand in ERCOT. Significant portion of this load growth are related to large load additions (Data Centers, Crypto and Hydrogen processing plants) in various regions including the Permian Basin region, Corpus Christi, and South DFW. The preliminary results of the 2024 RTP has indicated a need for significant transmission infrastructure need to accommodate the load growth and the need for large power transfer across the ERCOT system to support this demand. The 2024 RTP is evaluating projects alternatives to significantly expand the existing 345-kV network or building a new EHV backbone infrastructure (500-kV or 765-kV) to meet the long-term reliability, resiliency and growth.

The 2024 RTP will focus on some of the following benefits to compare the 500-kV or 765-kV EHV alternative to 345-kV expansion:

- Increased transfer capability to load centers to support continued load growth
- Flexibility on Generation Resource siting
- Outage coordination capacity to allow maintenance outages
- Impact to Texas consumers due to fewer ROW requirements
- Improved efficiency due to lower line losses as power travels further distances
- Possible retirement of series compensation devices
- Potential exit strategy for some current Generic Transmission Constraints (GTCs)

ERCOT expects to provide initial draft of holistic transmission plan for the 500-kV or 765-kV to serve the entire ERCOT region’s forecasted load reliably and efficiently for 2030, no later than September 2024. The 345-kV or the EHV import paths transmission upgrades proposed for the Permian Basin region for 2038 is a subset of the initial holistic transmission expansion being evaluated in the 2024 RTP. The 345-kV or EHV transfer paths solutions proposed in this Permian Basin Reliability Plan Study may be further optimized or changed to meet the overall system need in the RTP final plan. The final 2024 RTP plan will be completed no later than December 2024.

9 Conclusion

ERCOT with significant support from the relevant TDSPs performed the Permian Basin Reliability Plan Study, utilizing the S&P Global Permian Basin load forecast through 2038 and including the additional non-oil and gas load provided by the TDSPs serving loads in the Permian Basin region, and identified transmission upgrades necessary to reliably serve the projected loads in the Permian Basin region. ERCOT proposed a set of transmission upgrades to connect and reliably serve the projected S&P Global Permian Basin load as well as additional non-oil and gas load. The proposed transmission upgrades are categorized as local transmission upgrades and import paths. The study identified the need for projected load growth in 2030 and 2038. The transmission upgrades identified in this study for 2030 are a subset of the transmission upgrades for 2038.

Three different import path options were evaluated: 345-kV import paths, 500-kV EHV import paths, and 765-kV EHV import paths. The 345-kV import path option was evaluated for 2030 and 2038. 500-kV and 765-kV EHV import path options were evaluated for 2038. The two EHV options will be part of a systemwide EHV study to be completed later in 2024.

Tables 9.1 and 9.2 summarize the cost estimates for common local upgrades, import paths, incremental local upgrades associated with each import path option and total upgrades for 2030 and 2038.

Table 9.1: Summary of the Cost Estimates ($Billion) for 2030*

	2030
Common Local Upgrades	4.02
Import Paths	3.99
Incremental Local Upgrades	1.03
Total	9.04

* 2030 Import path and Incremental Local Upgrades are subset of 2038 345-kV Option

Table 9.2: Summary of the Cost Estimates ($Billion) for 2038

	2038		
	345-kV Option	500-kV Option	765-KV Option
Common Local Upgrades	4.02	4.02	4.02
Import Paths	7.69	10.61	9.06
Incremental Local Upgrades	1.23	0.69	0.69
Total	12.95	15.32	13.77

Appendix

Appendix A.1

Table A.1: List of Generation Added to 2030 and 2038 Study Cases Based on February 2024 GIS Report (Total Capacity of Approximately 17,170 MW)

GINR	Project Name	Fuel	Project COD	Capacity (~MW)	County
19INR0203	Angelo Solar	SOL	August-24	195.4	Tom Green
21INR0424	Tierra Bonita Solar	SOL	August-24	309.7	Pecos
22INR0495	TIMBERWOLF BESS 2	BAT	December-23	150.0	Crane
22INR0502	Shamrock	WND	July-24	223.9	Crockett
23INR0219	Dogfish BESS	BAT	December-24	75.0	Pecos
23INR0387	Pioneer DJ Wind	WND	April-24	140.3	Midland
23INR0418	Angelo Storage	BAT	May-24	103.0	Tom Green
23INR0470	BoCo BESS	BAT	June-24	155.5	Borden
23INR0525	Pyron Wind Repower	WND	February-24	19.9	Nolan
24INR0273	Al Pastor BESS	BAT	September-24	100.8	Dawson
14INR0033	Goodnight Wind	WND	February-24	258.1	Armstrong
19INR0054	Monte Cristo 1 Wind	WND	September-25	236.9	Hidalgo
19INR0134	Cottonwood Bayou Solar	SOL	June-24	351.4	Brazoria
20INR0040	Montgomery Ranch Wind	WND	February-24	200.2	Foard
20INR0208	Signal Solar	SOL	March-25	51.8	Hunt
20INR0210	Hopkins Solar	SOL	December-23	253.1	Hopkins
20INR0248	Second Division Solar	SOL	September-24	100.3	Brazoria
21INR0012	Air Products GCA	GAS	December-23	14.0	Galveston
21INR0302	Aureola Solar	SOL	June-24	203.0	Milam
21INR0303	Mandorla Solar	SOL	November-24	254.0	Milam
21INR0304	Halo Solar	SOL	June-24	254.0	Bell
21INR0325	Sheep Creek Wind	WND	December-23	153.0	Callahan
21INR0368	Eliza Solar	SOL	November-24	151.6	Kaufman
21INR0389	Hollywood Solar	SOL	June-24	353.4	Wharton
21INR0450	Danish Fields Storage	BAT	February-24	152.4	Wharton
21INR0505	Ramsey Storage	BAT	December-25	510.4	Wharton
21INR0511	Wolf Ridge Repower	WND	April-24	9.0	Cooke
21INR0515	Roadrunner Crossing Wind II	WND	December-23	126.7	Eastland
22INR0251	Shaula I Solar	SOL	October-25	205.2	DeWitt
22INR0260	Eliza Storage	BAT	November-24	100.2	Kaufman
22INR0261	Dorado Solar	SOL	December-25	406.3	Callahan
22INR0267	Shaula II Solar	SOL	May-26	205.2	DeWitt
22INR0353	BRP Carina BESS	BAT	December-24	151.9	Nueces
22INR0354	XE MURAT Solar	SOL	May-24	60.4	Harris
22INR0366	BRP Libra BESS	BAT	January-24	206.2	Guadalupe
22INR0422	Ferdinand Grid BESS	BAT	May-26	202.7	Bexar

GINR	Project Name	Fuel	Project COD	Capacity (~MW)	County
23INR0026	Baker Branch Solar	SOL	August-24	469.4	Lamar
23INR0054	Tanglewood Solar	SOL	January-25	257.0	Brazoria
23INR0062	Noria Storage	BAT	September-25	75.0	Nueces
23INR0114	True North Solar	SOL	June-24	238.3	Falls
23INR0154	Ebony Energy Storage	BAT	April-24	203.5	Comal
23INR0159	Five Wells Storage	BAT	January-24	220.8	Bell
23INR0239	Giga Texas Energy Storage	BAT	January-24	131.1	Travis
23INR0296	Trojan Solar	SOL	February-26	151.3	Cooke
23INR0331	Talitha BESS	BAT	June-24	61.4	Jim Wells
23INR0367	Fewell Solar	SOL	September-25	203.5	Limestone
23INR0381	Soportar ESS	BAT	March-25	102.1	Bexar
23INR0408	TECO GTG2	GAS	January-24	50.0	Harris
23INR0460	GULF STAR STORAGE	BAT	June-24	301.0	Wharton
23INR0637	Goodnight Wind II	WND	December-24	258.3	Armstrong
24INR0015	Five Wells Solar	SOL	December-23	322.8	Bell
24INR0038	SP Jaguar Solar	SOL	June-25	300.0	McLennan
24INR0039	SP Jaguar BESS	BAT	June-25	300.0	McLennan
24INR0070	Sypert Branch Solar Project	SOL	June-25	261.8	Milam
24INR0109	Oriana BESS	BAT	July-25	60.3	Victoria
24INR0265	Ironman BESS	BAT	November-24	304.2	Brazoria
24INR0281	Red Egret BESS	BAT	June-25	309.0	Galveston
24INR0427	CPS AvR CT1 Rotor Replacement	GAS	January-24	11.3	Bexar
24INR0436	Carambola BESS	BAT	May-26	97.4	Hidalgo
25INR0162	SOHO II BESS	BAT	January-25	206.3	Brazoria
25INR0223	Uhland Maxwell	GAS	April-25	188.4	Caldwell
25INR0232	Isaac Solar	SOL	March-26	51.6	Matagorda
22INR0555	Guevara Storage	BAT	July-25	125.4	Rockwall
23INR0349	Tokio Solar	SOL	August-25	177.6	McLennan
24INR0010	Pinnington Solar	SOL	October-25	666.1	Jack
24INR0100	Sheep Creek Storage	BAT	July-24	142.0	Callahan
24INR0138	Midpoint Storage	BAT	August-25	52.2	Hill
24INR0139	Midpoint Solar	SOL	August-25	103.8	Hill
24INR0140	Gaia Storage	BAT	July-25	76.8	Navarro
24INR0141	Gaia Solar	SOL	July-25	152.7	Navarro
24INR0295	Lucky Bluff BESS	BAT	May-25	100.8	Erath
25INR0105	Diver Solar	SOL	June-26	228.2	Limestone
23INR0091	Cascade Solar	SOL	December-24	254.2	Brazoria
24INR0337	Eldora Solar	SOL	June-26	200.9	Matagorda
24INR0312	Wigeon Whistle BESS	BAT	September-24	122.9	Collin
24INR0338	Eldora BESS	BAT	June-26	201.3	Matagorda
25INR0328	Longbow BESS	BAT	November-24	180.8	Brazoria
20INR0217	CAROL wind	WND	April-25	165.4	Potter

GINR	Project Name	Fuel	Project COD	Capacity (~MW)	County
21INR0240	La Casa Wind	WND	June-25	148.4	Stephens
21INR0379	Ash Creek Solar	SOL	January-25	417.7	Hill
23INR0030	Langer Solar	SOL	March-27	249.8	Bosque
23INR0070	Chillingham Solar	SOL	December-24	352.4	Bell
23INR0336	Bypass Battery Storage	BAT	December-25	206.9	Fort Bend
24INR0632	Cedro Hill Wind Repower	WND	December-24	9.9	Webb
26INR0042	Valhalla Solar	SOL	May-26	306.8	Brazoria
23INR0403	Connolly Storage	BAT	August-24	125.4	Wise
24INR0023	Compadre Solar	SOL	December-24	406.1	Hill
24INR0208	Eastbell Milam Solar II	SOL	December-24	152.5	Milam
24INR0329	XE Murat Storage	BAT	December-24	62.1	Harris

Appendix A.2:

Sample plots demonstrating acceptable responses to system contingencies for both the 345-kV and 765-kV import path options are shown below.

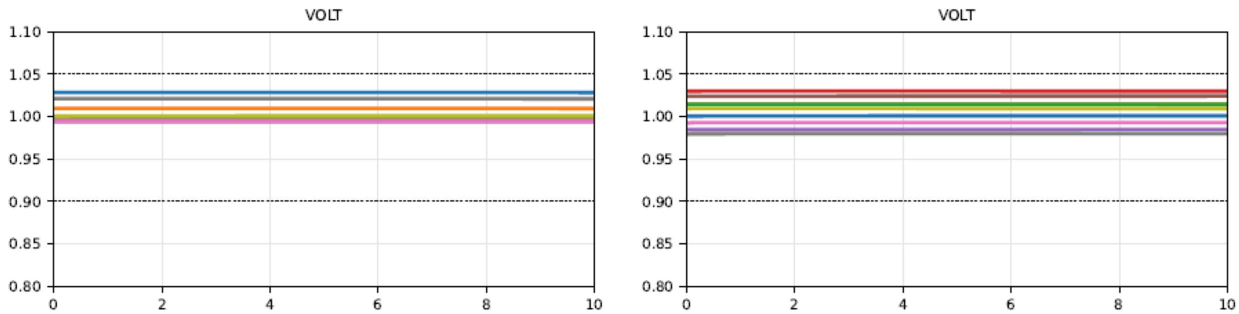

Figure A2.1: Sample Flat Start Plots for 345-kV Import Path Option

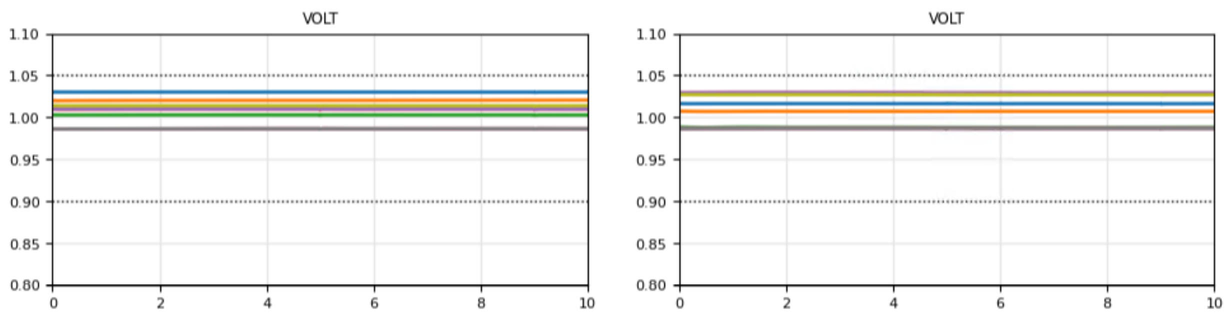

Figure A2.2: Sample Flat Start Plots for 765-kV Import Path Option

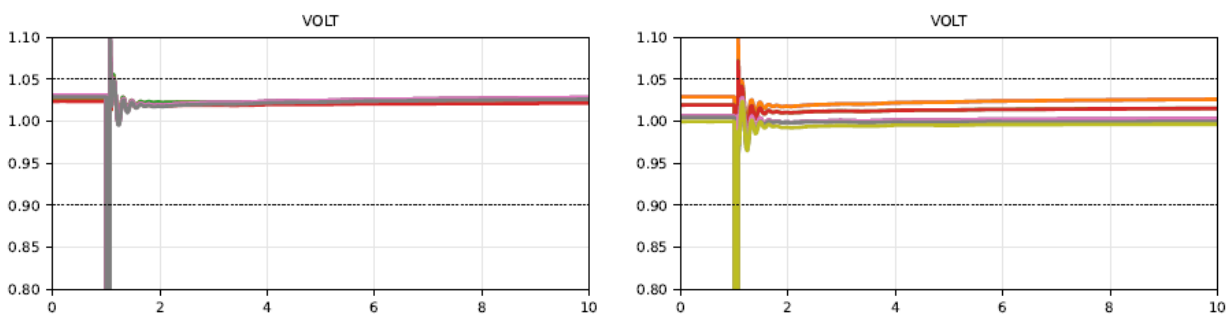

Figure A2.3: Sample P7 Contingency Event Plots for 345-kV Import Path Option

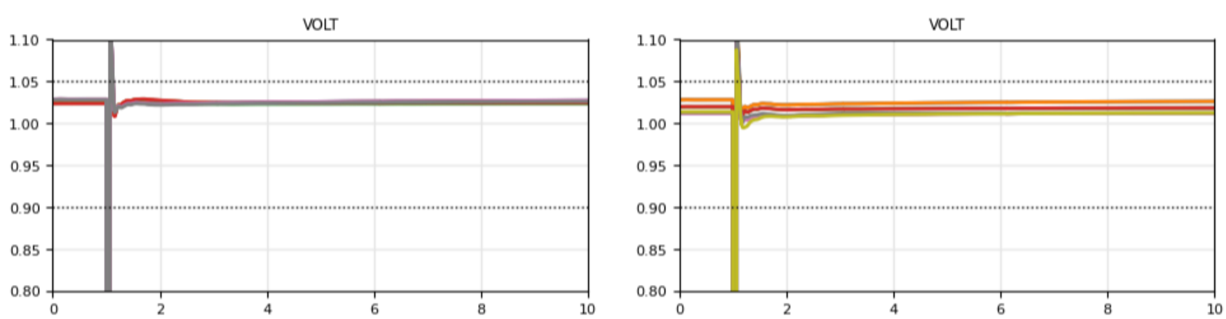

Figure A2.4: Sample P7 Contingency Event Plots for 765-kV Import Path Option