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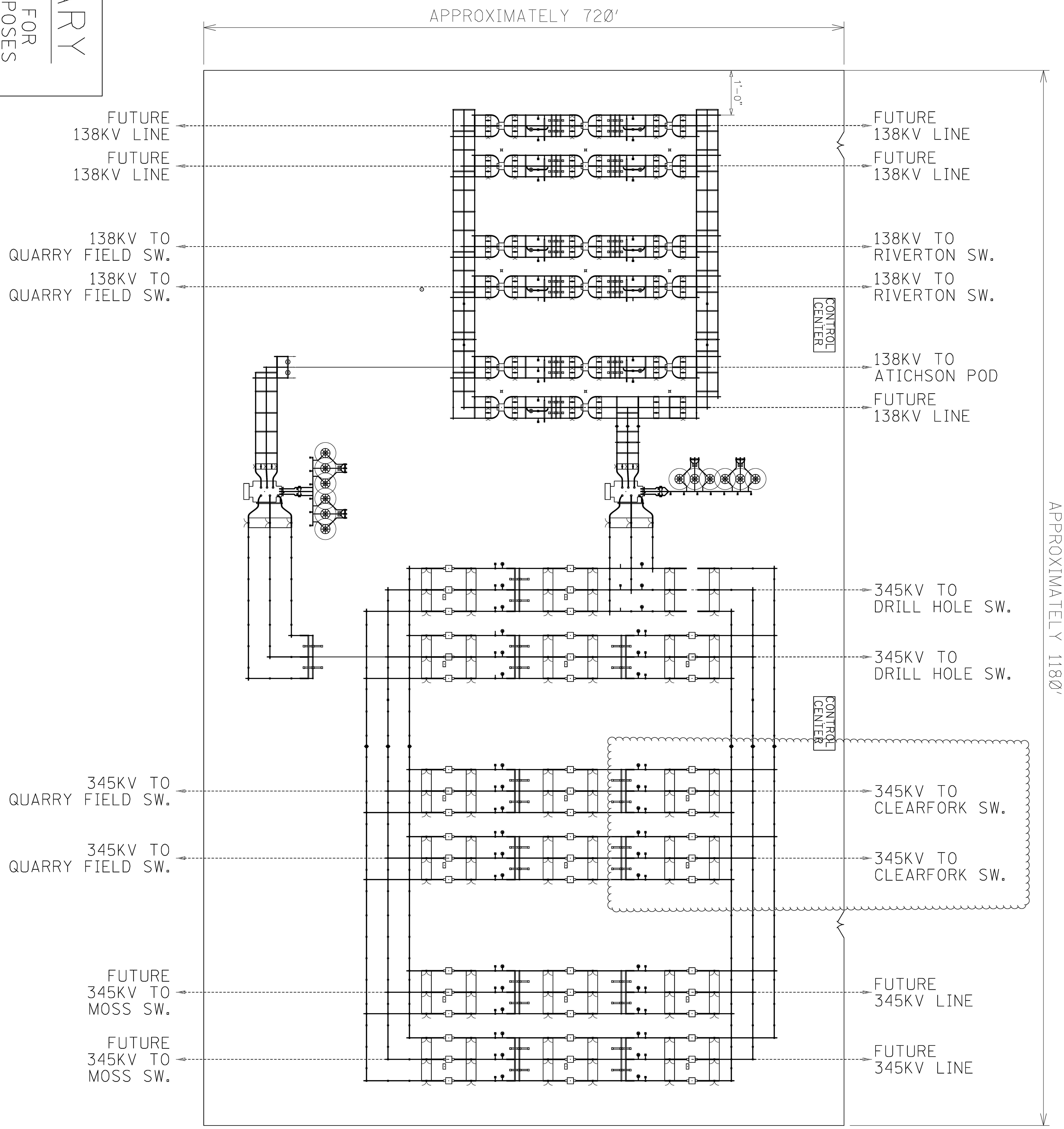
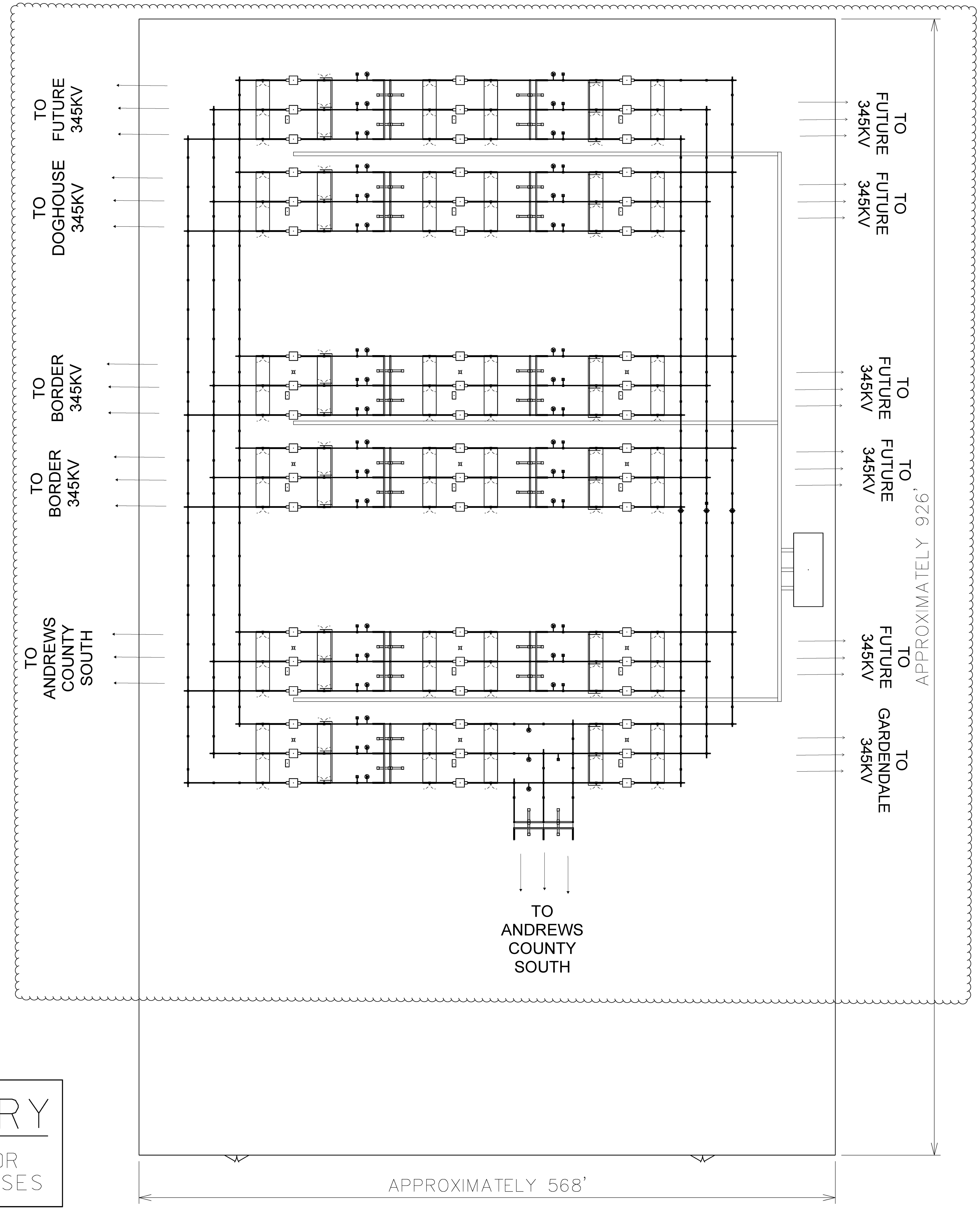


ATTACHMENT NO. 2-A

BORDER SWITCH EQUIPMENT LAYOUT	ATTACHMENT 2-A	ONCOR TRANSMISSION ENGINEERING

ATTACHMENT NO. 2-B

ONCOR.
TRANSMISSION ENGINEERING



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ATTACHMENT NO. 2-B

CLEARFORK SWITCH EQUIPMENT LAYOUT

PROPOSED BORDER SWITCH - CLEARFORK SWITCH 345 KV TRANSMISSION LINE PROJECT
ATTACHMENT NO. 3 - COST ESTIMATES

	Route 294	Route 505	Route 514	Route 515	Route 516	Route 517	Route 518	Route 520
Right-of-way and Land Acquisition	$19,628,000	$18,998,000	$19,948,000	$19,925,000	$19,771,000	$18,944,000	$19,148,000	$19,065,000
Engineering and Design (Utility)	$2,354,000	$2,300,000	$2,376,000	$2,373,000	$2,335,000	$2,264,000	$2,268,000	$2,267,000
Engineering and Design (Contract)	$5,262,000	$5,138,000	$5,307,000	$5,300,000	$5,217,000	$5,059,000	$5,067,000	$5,070,000
Procurement of Material and Equipment (including stores)	$82,070,000	$80,897,000	$82,028,000	$81,387,000	$80,574,000	$78,023,000	$79,004,000	$79,892,000
Construction of Facilities (Utility)	$0	$0	$0	$0	$0	$0	$0	$0
Construction of Facilities (Contract)	$134,851,000	$133,489,000	$134,226,000	$132,863,000	$131,840,000	$128,087,000	$129,963,000	$131,542,000
Other (all costs not included in the above categories)	$0	$0	$0	$0	$0	$0	$0	$0
Estimated Total Transmission Line Cost	**$244,165,000**	**$240,822,000**	**$243,885,000**	**$241,848,000**	**$239,737,000**	**$232,377,000**	**$235,450,000**	**$237,836,000**
Estimated Oncor Substation Facilities Cost	$43,794,000	$43,794,000	$43,794,000	$43,794,000	$43,794,000	$43,794,000	$43,794,000	$43,794,000
Estimated Total Project Cost*	**$287,959,000**	**$284,616,000**	**$287,679,000**	**$285,642,000**	**$283,531,000**	**$276,171,000**	**$279,244,000**	**$281,630,000**

Note:

*Estimated costs are based on Oncor's historical costs and do not include escalation for existing or future tariffs/import duties that may be levied on project materials, equipment, and supplies.

PROPOSED BORDER SWITCH - CLEARFORK SWITCH 345 KV TRANSMISSION LINE PROJECT
ATTACHMENT NO. 3 - COST ESTIMATES

	Route 525	Route 1040	Route 1042	Route 1118	Route 1263	Route 1356	Route 1385	Route 1386
Right-of-way and Land Acquisition	$19,330,000	$20,120,000	$19,138,000	$23,381,000	$23,236,000	$19,662,000	$20,131,000	$19,593,000
Engineering and Design (Utility)	$2,308,000	$2,382,000	$2,273,000	$2,663,000	$2,668,000	$2,325,000	$2,333,000	$2,305,000
Engineering and Design (Contract)	$5,160,000	$5,320,000	$5,079,000	$5,954,000	$5,966,000	$5,197,000	$5,218,000	$5,158,000
Procurement of Material and Equipment (including stores)	$79,403,000	$80,146,000	$76,782,000	$100,753,000	$100,934,000	$79,149,000	$83,534,000	$81,085,000
Construction of Facilities (Utility)	$0	$0	$0	$0	$0	$0	$0	$0
Construction of Facilities (Contract)	$130,236,000	$129,820,000	$125,044,000	$168,428,000	$168,689,000	$128,436,000	$136,107,000	$131,375,000
Other (all costs not included in the above categories)	$0	$0	$0	$0	$0	$0	$0	$0
Estimated Total Transmission Line Cost	**$236,437,000**	**$237,788,000**	**$228,316,000**	**$301,179,000**	**$301,493,000**	**$234,769,000**	**$247,323,000**	**$239,516,000**
Estimated Oncor Substation Facilities Cost	$43,794,000	$43,794,000	$43,794,000	$43,794,000	$43,794,000	$43,794,000	$43,794,000	$43,794,000
Estimated Total Project Cost*	**$280,231,000**	**$281,582,000**	**$272,110,000**	**$344,973,000**	**$345,287,000**	**$278,563,000**	**$291,117,000**	**$283,310,000**

Note:

*Estimated costs are based on Oncor's historical costs and do not include escalation for existing or future tariffs/import duties that may be levied on project materials, equipment, and supplies.

PROPOSED BORDER SWITCH - CLEARFORK SWITCH 345 KV TRANSMISSION LINE PROJECT
ATTACHMENT NO. 3 - COST ESTIMATES

	Route 1387	Route 1388	Route 1391	Route 1422	Route 1423	Route 1424	Route 1425	Route 1427
Right-of-way and Land Acquisition	$20,295,000	$19,757,000	$19,858,000	$18,347,000	$18,551,000	$19,006,000	$18,468,000	$18,631,000
Engineering and Design (Utility)	$2,337,000	$2,309,000	$2,346,000	$2,186,000	$2,190,000	$2,217,000	$2,189,000	$2,193,000
Engineering and Design (Contract)	$5,227,000	$5,167,000	$5,248,000	$4,888,000	$4,896,000	$4,959,000	$4,899,000	$4,908,000
Procurement of Material and Equipment (including stores)	$84,427,000	$81,978,000	$80,596,000	$75,620,000	$76,601,000	$79,938,000	$77,489,000	$78,382,000
Construction of Facilities (Utility)	$0	$0	$0	$0	$0	$0	$0	$0
Construction of Facilities (Contract)	$138,046,000	$133,314,000	$130,069,000	$123,646,000	$125,522,000	$131,833,000	$127,101,000	$129,040,000
Other (all costs not included in the above categories)	$0	$0	$0	$0	$0	$0	$0	$0
Estimated Total Transmission Line Cost	**$250,332,000**	**$242,525,000**	**$238,117,000**	**$224,687,000**	**$227,760,000**	**$237,953,000**	**$230,146,000**	**$233,154,000**
Estimated Oncor Substation Facilities Cost	$43,794,000	$43,794,000	$43,794,000	$43,794,000	$43,794,000	$43,794,000	$43,794,000	$43,794,000
Estimated Total Project Cost*	**$294,126,000**	**$286,319,000**	**$281,911,000**	**$268,481,000**	**$271,554,000**	**$281,747,000**	**$273,940,000**	**$276,948,000**

Note:

*Estimated costs are based on Oncor's historical costs and do not include escalation for existing or future tariffs/import duties that may be levied on project materials, equipment, and supplies.

PROPOSED BORDER SWITCH - CLEARFORK SWITCH 345 KV TRANSMISSION LINE PROJECT
ATTACHMENT NO. 3 - COST ESTIMATES

	Route 1454	Route 1520	Route 1528	Route 1533	Route 1535	Route 1548	Route 1550	Route 1552
Right-of-way and Land Acquisition	$20,933,000	$21,241,000	$23,192,000	$20,997,000	$20,888,000	$23,463,000	$23,209,000	$23,100,000
Engineering and Design (Utility)	$2,446,000	$2,514,000	$2,771,000	$2,450,000	$2,440,000	$2,710,000	$2,650,000	$2,640,000
Engineering and Design (Contract)	$5,475,000	$5,626,000	$6,196,000	$5,482,000	$5,459,000	$6,059,000	$5,928,000	$5,905,000
Procurement of Material and Equipment (including stores)	$89,907,000	$88,327,000	$94,050,000	$89,951,000	$89,708,000	$99,238,000	$100,520,000	$100,277,000
Construction of Facilities (Utility)	$0	$0	$0	$0	$0	$0	$0	$0
Construction of Facilities (Contract)	$149,583,000	$145,124,000	$152,801,000	$149,803,000	$149,418,000	$163,640,000	$168,164,000	$167,779,000
Other (all costs not included in the above categories)	$0	$0	$0	$0	$0	$0	$0	$0
Estimated Total Transmission Line Cost	**$268,344,000**	**$262,832,000**	**$279,010,000**	**$268,683,000**	**$267,913,000**	**$295,110,000**	**$300,471,000**	**$299,701,000**
Estimated Oncor Substation Facilities Cost	$43,794,000	$43,794,000	$43,794,000	$43,794,000	$43,794,000	$43,794,000	$43,794,000	$43,794,000
Estimated Total Project Cost*	**$312,138,000**	**$306,626,000**	**$322,804,000**	**$312,477,000**	**$311,707,000**	**$338,904,000**	**$344,265,000**	**$343,495,000**

Note:

*Estimated costs are based on Oncor's historical costs and do not include escalation for existing or future tariffs/import duties that may be levied on project materials, equipment, and supplies.

PROPOSED BORDER SWITCH - CLEARFORK SWITCH 345 KV TRANSMISSION LINE PROJECT
ATTACHMENT NO. 3 - COST ESTIMATES

	Route 1555	Route 1574	Route 1575	Route 2457	Route 2585	Route 3210	Route 3502	Route 3624
Right-of-way and Land Acquisition	$23,202,000	$23,938,000	$23,733,000	$24,035,000	$21,678,000	$23,825,000	$23,437,000	$24,262,000
Engineering and Design (Utility)	$2,677,000	$2,823,000	$2,806,000	$2,763,000	$2,568,000	$2,732,000	$2,748,000	$2,771,000
Engineering and Design (Contract)	$5,986,000	$6,311,000	$6,272,000	$6,176,000	$5,742,000	$6,104,000	$6,142,000	$6,191,000
Procurement of Material and Equipment (including stores)	$98,895,000	$101,650,000	$100,458,000	$103,451,000	$93,063,000	$104,158,000	$98,643,000	$107,456,000
Construction of Facilities (Utility)	$0	$0	$0	$0	$0	$0	$0	$0
Construction of Facilities (Contract)	$164,534,000	$165,314,000	$163,201,000	$172,600,000	$154,500,000	$173,056,000	$160,350,000	$178,426,000
Other (all costs not included in the above categories)	$0	$0	$0	$0	$0	$0	$0	$0
Estimated Total Transmission Line Cost	**$295,294,000**	**$300,036,000**	**$296,470,000**	**$309,025,000**	**$277,551,000**	**$309,875,000**	**$291,320,000**	**$319,106,000**
Estimated Oncor Substation Facilities Cost	$43,794,000	$43,794,000	$43,794,000	$43,794,000	$43,794,000	$43,794,000	$43,794,000	$43,794,000
Estimated Total Project Cost*	**$339,088,000**	**$343,830,000**	**$340,264,000**	**$352,819,000**	**$321,345,000**	**$353,669,000**	**$335,114,000**	**$362,900,000**

Note:

*Estimated costs are based on Oncor's historical costs and do not include escalation for existing or future tariffs/import duties that may be levied on project materials, equipment, and supplies.

PROPOSED BORDER SWITCH - CLEARFORK SWITCH 345 KV TRANSMISSION LINE PROJECT
ATTACHMENT NO. 3 - COST ESTIMATES

	Route 3625	Route 3648	Route 3650	Route 3651	Route 3652	Route 3653	Route 3654
Right-of-way and Land Acquisition	$23,724,000	$24,357,000	$18,982,000	$19,086,000	$20,783,000	$18,965,000	$19,792,000
Engineering and Design (Utility)	$2,743,000	$2,909,000	$2,228,000	$2,263,000	$2,494,000	$2,260,000	$2,331,000
Engineering and Design (Contract)	$6,131,000	$6,498,000	$4,981,000	$5,063,000	$5,578,000	$5,052,000	$5,210,000
Procurement of Material and Equipment (including stores)	$104,436,000	$104,636,000	$75,792,000	$80,318,000	$87,738,000	$78,449,000	$81,000,000
Construction of Facilities (Utility)	$0	$0	$0	$0	$0	$0	$0
Construction of Facilities (Contract)	$173,694,000	$169,116,000	$123,264,000	$131,832,000	$143,889,000	$128,377,000	$132,130,000
Other (all costs not included in the above categories)	$0	$0	$0	$0	$0	$0	$0
Estimated Total Transmission Line Cost	**$310,728,000**	**$307,516,000**	**$225,247,000**	**$238,562,000**	**$260,482,000**	**$233,103,000**	**$240,463,000**
Estimated Oncor Substation Facilities Cost	$43,794,000	$43,794,000	$43,794,000	$43,794,000	$43,794,000	$43,794,000	$43,794,000
Estimated Total Project Cost*	**$354,522,000**	**$351,310,000**	**$269,041,000**	**$282,356,000**	**$304,276,000**	**$276,897,000**	**$284,257,000**

Note:
*Estimated costs are based on Oncor's historical costs and do not include escalation for existing or future tariffs/import duties that may be levied on project materials, equipment, and supplies.

ERCOT Delaware Basin Load Integration Study

Final

ATTACHMENT NO. 4

Document Revisions

Date	Version	Description	Author(s)
12/23/2019	1.0	Final	Ying Li
		Reviewed by	Sun Wook Kang, Shun Hsien (Fred) Huang, Jeff Billo

Executive Summary

ERCOT, with extensive review and input by Transmission Service Providers (TSPs) and stakeholders, performed the Delaware Basin Load Integration Study. This report describes potential reliability transmission needs to meet higher-than-forecasted electric demand driven by the oil and natural gas industry and the associated economic expansion in the Delaware Basin area located in the ERCOT Far West Weather Zone. The Delaware Basin area spans the following eight counties: Brewster, Culberson, Jeff Davis, Loving, Pecos, Reeves, Ward, and Winkler.

The Far West Weather Zone, especially the Delaware Basin area, has the highest peak demand growth rate in the ERCOT system in recent years. The historical load data from 2013 to 2019 showed that the average annual peak load growth rate of the Far West Weather Zone is approximately 11%, well above the ERCOT system-wide average.

Several planned transmission projects, including the Far West Texas Project (FWTP), Far West Texas Dynamic Reactive Devices (DRD), and Far West Texas Project 2 (FWTP2), endorsed by the ERCOT Board of Directors in 2017 and 2018, are expected to be sufficient to meet the current load forecast for the Far West Weather Zone through 2024. As the oil and gas load in the Delaware Basin area continues to develop, ensuring that the necessary transmission improvements are in place in time to accommodate the rapid load growth will continue to be a challenge. The nature of the industry is such that oil and gas customers are not able to accurately project their demand needs more than one or two years ahead of time while transmission improvements can take up to six years to complete planning studies, routing analysis (if needed), regulatory approvals, route acquisition (if needed), design, and construction.

The main purpose of the study is to identify potential reliability needs and cost-effective bulk power system upgrades, particularly long lead time transmission improvements, which may be necessary if the load in the Delaware Basin area increases at a rapid pace. ERCOT performed a steady state reliability analysis using a higher-than-forecasted (i.e. conceptual plus planned) load growth in the Delaware Basin area. The total load assumed in the study area was 5,372 MW, which is double the area load (2,688 MW) assumed in the ERCOT 2019 Regional Transmission Plan (RTP) for year 2024.

To address the reliability needs for the assumed total load, four short-listed long lead time transmission alternatives and a set of common transmission upgrades were identified to reliably serve the assumed load in the study area under both normal and contingency conditions. As a result, ERCOT identified a roadmap for the long lead time transmission upgrades (i.e. new 345-kV transmission lines) and the associated triggers in terms of the load level in the Delaware Basin area. As the common transmission upgrades and the upgrade of existing 345-kV lines are expected to require relatively less lead time, they were not considered in the roadmap development. Rather, they were assumed to be completed prior to first trigger level. Table E.1 lists the details of transmission additions associated with each stage.

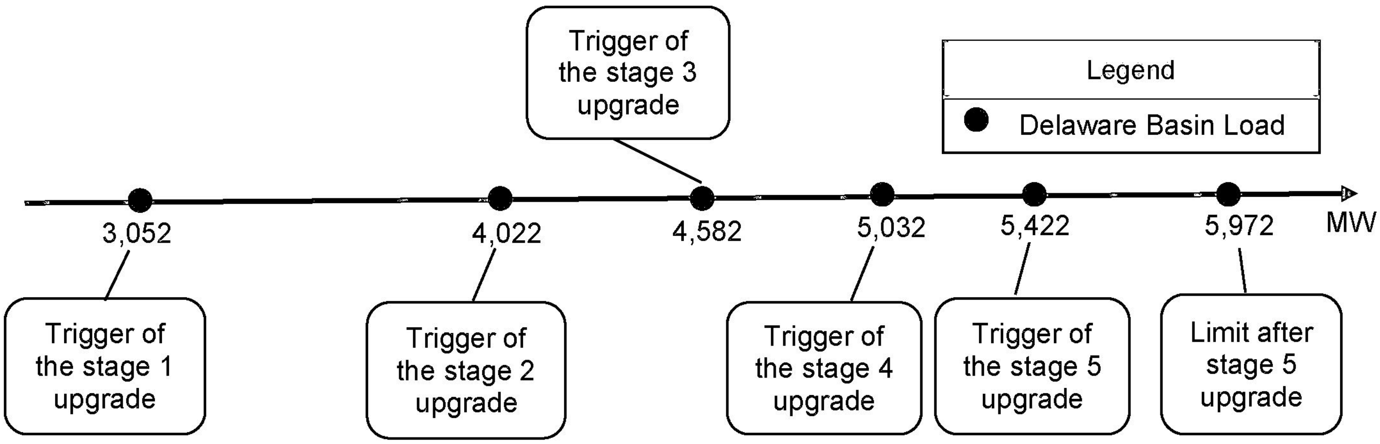

Figure E.1 Delaware Basin Transmission Upgrade Roadmap

Table E.1 Delaware Basin Transmission Upgrade Roadmap – Detailed Project List

Stage	Estimated Delaware Basin Load Level (MW)	Upgrade Element	Estimated Upgrade Cost ($M)	Trigger
1	3,052	Add a second circuit on the existing Big Hill - Bakersfield 345-kV line	69	Import Needs
2	4,022	A new Bearkat - North McCamey - Sand Lake double circuit 345-kV line	371	Import Needs
3	4,582	A new Riverton - Owl Hills single circuit 345-kV line	41	Culberson Loop Needs
4	5,032	Riverton - Sand Lake 138-kV to 345-kV conversion and a new Riverton - Sand Lake 138-kV line	56	Culberson Loop Needs
5	5,422	A new Faraday - Lamesa - Clearfork - Riverton double circuit 345-kV line	444	Import Needs

As noted above, all of the common transmission upgrades were included in the study while developing this roadmap. The addition of a second circuit on the existing structures of the Big Hill - Bakersfield 345-kV line, identified as Stage 1 upgrade, will be needed if the Delaware Basin load exceeds 3,052 MW. The Stage 2 upgrade, a new import path consisting of 345-kV circuits from Bearkat to North McCamey to Sand Lake, will be needed if the Delaware Basin load exceeds 4,022 MW. The Stage 2 upgrade is also expected to improve the existing Generic Transmission Constraints (GTCs) in the McCamey and Bearkat areas.

With Stage 1 and Stage 2 upgrades assumed in service, voltage instability was observed in the Culberson Loop when the Delaware Basin area load reaches 4,582 MW. Stage 3 and Stage 4 upgrades will be necessary to address the Culberson Loop voltage instability.

When the load in the Delaware Basin area exceeds 5,422 MW, the Delaware Basin area may need an additional new import path as shown in the Stage 5 upgrade.

Although the study year was 2024, it should not be assumed that all of the improvement projects are needed in 2024. The actual need for each project could be sooner or later than 2024 depending on the growth rate and location of the load in the Delaware Basin. Other factors that could affect the need for and timing of the upgrades include, but are not limited to, common transmission upgrade implementation, availability and dispatch of the generation in the study area, impedance of the new conductors, transmission upgrade cost estimates, and the results of dynamic stability analysis, which was not conducted as part of this study.

The TSPs and ERCOT will continue to study the Delaware Basin as part of their normal planning processes and recommend new transmission projects as necessary to address new customer interconnections, new generation development, and system needs.

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Disclaimer

It should be noted that the identified transmission improvements in this document are based on the assumptions used in this study. Assumptions that could change the results of this analysis include, but are not limited to, the following: actual load addition size, timing, and location; common transmission upgrade implementation; availability and dispatch of the generation in the study area; impedance of the new conductors; transmission upgrade cost estimates; and the results of dynamic stability analysis.

The primary focus of this study was to identify and to create a roadmap for long lead time transmission improvements, such as new extra high voltage transmission lines, to serve assumed conceptual and planned loads in the Delaware Basin study area. This study addressed transmission system thermal violations and steady state voltage stability issues identified during the analyses for the Far West Weather Zone.

A local reactive planning assessment was not completed as part of this study. The location and size of reactive devices were not optimized as part of this assessment.

1. Introduction

Over the past several years, the Far West Weather Zone, especially in the Delaware Basin area with significant oil and natural gas load, has had the highest peak demand growth rate in the ERCOT region. The average annual peak demand growth rate of the Far West Weather Zone was about 11% according to historic data between 2013 and 2019. The significant load growth rate was primarily driven by the oil and natural gas business development. Figure 1.1 shows the map of tectonic subdivision of the Delaware Basin area.

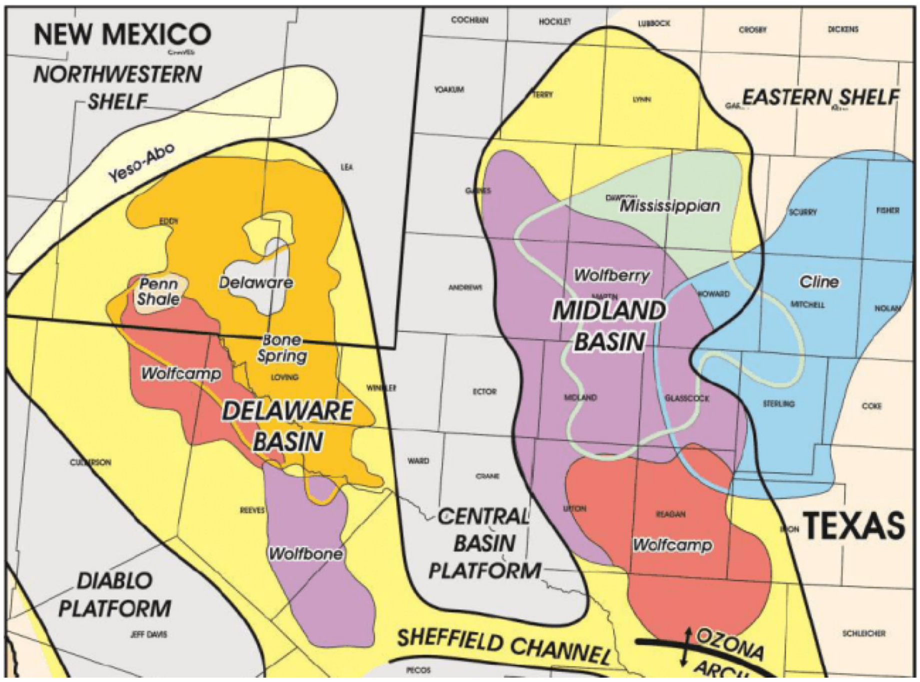

Figure 1.1 Map of Tectonic Subdivision of the Delaware Basin[1]

To accommodate the significant load growth and address the transmission needs in the area, the ERCOT Board endorsed the Far West Texas Project (FWTP), a Tier 1 transmission project in June 2017. In June 2018, the ERCOT Board endorsed the Far West Texas Dynamic Reactive Devices (DRD) Project and the Far West Texas Project 2 (FWTP2) to meet the projected contractually-confirmed load level in the Culberson Loop located in the Delaware Basin area. The FWTP, DRD, and FWTP2 projects, which include a new 345-kV double circuit transmission loop and multiple dynamic reactive devices, are scheduled to be completed by the end of 2020.

These projects along with other planned transmission upgrades are expected to be sufficient to meet the current forecasted load in the Delaware Basin area through 2024. However, if the load in the area develops faster than forecasted, it could outgrow the load serving capability of these planned upgrades. In addition, ensuring that the transmission improvements are in place in time to accommodate the rapid load growth will continue to be a challenge because the nature of the industry is such that oil and gas customers are not able to accurately project their demand needs more than one or two years ahead of time while transmission improvements can take up to six years to complete

[1] https://www.oilandgas360.com/ngl-energy-partners-adds-water-sources-for-oil-gas-operators-in-the-permian/

planning studies, routing analysis (if needed), regulatory approvals, route acquisition (if needed), design, and construction. Due to the nature of relatively short notice from the oil and gas customers providing financial commitment for new load additions, it is difficult to accurately forecast the load five years ahead during the typical planning studies.

Figure 1.2 shows the load comparison of five-year ahead load forecast in the ERCOT SSWG cases and actual historic load in the Delaware Basin area. In 2014, the projected 2019 summer peak demand in the SSWG case for the Delaware Basin area was 595 MW; the recorded peak demand in the Delaware Basin area in 2019 was 1,132 MW, which significantly exceeded the five-year out projected load from 2014. Figure 1.2 also shows substantial increase in the load forecast projected for year 2024. This is primarily due to a significant amount of conceptual loads added by TSPs to the Delaware Basin area.

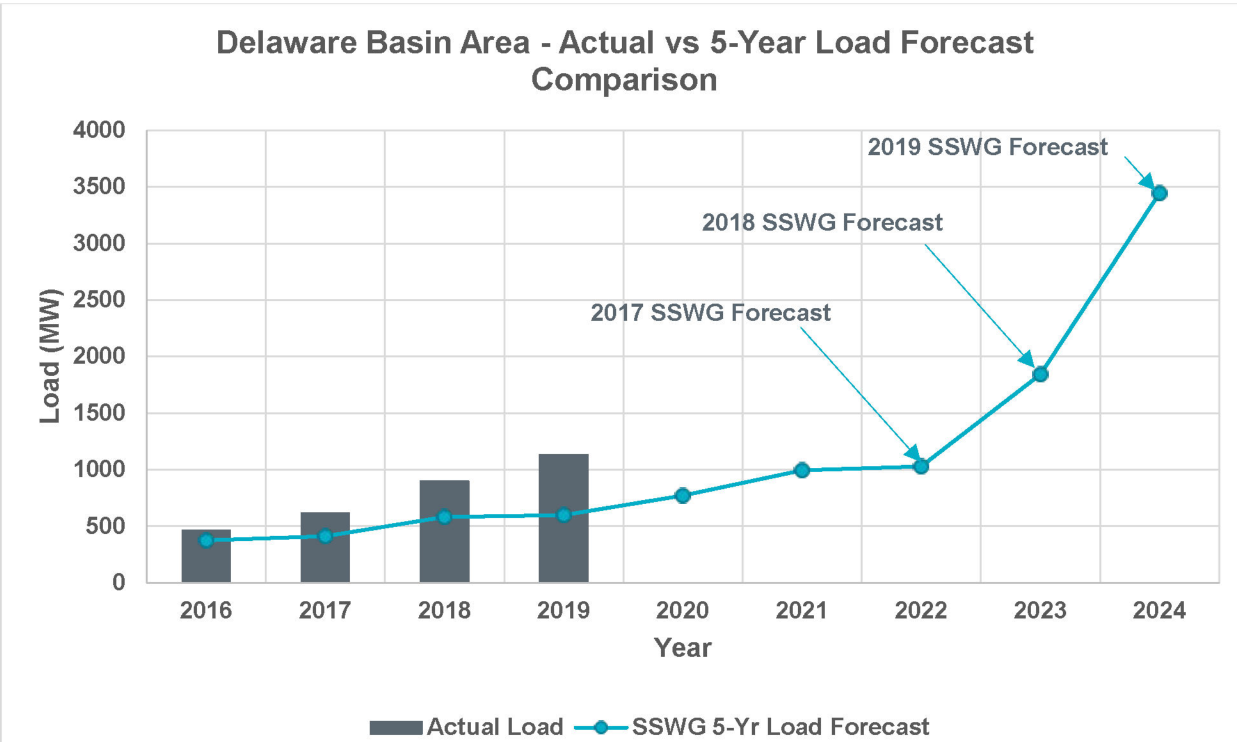

Figure 1.2 Actual and 5-year Load Forecast in the Delaware Basin Area

Given the challenges associated with uncertainties of the load growth in the Delaware Basin area, ERCOT initiated the Delaware Basin Load Integration Study to perform a reliability analysis for higher-than-forecasted load growth in the Delaware Basin area. ERCOT worked closely with TSPs and stakeholders throughout the study.

ERCOT performed steady state analyses using the updated case and identified both long-lead time transmission improvements and a set of common transmission upgrades to reliably serve the assumed load in this study. The common transmission upgrades include upgrading existing transmission facilities, adding new 138-kV transmission lines, and adding new reactive power devices. These common transmission upgrades were assumed to be in-service in the import path evaluation and the development of the long-lead-time-transmission-upgrade roadmap. It should be noted that these common transmission upgrades are expected to require relatively shorter lead time but will be highly dependent on the size and location of the new load additions. Additional studies such as dynamic stability analysis will need to be conducted to optimize the size, location and technology of the new reactive power devices identified as placeholders.

2. Criteria, Study Assumption and Methodology

The study criteria, assumptions, and methodology are described in this section.

2.1. Study Criteria and Monitored Area

The Delaware Basin area includes the following eight counties: Brewster, Culberson, Jeff Davis, Loving, Pecos, Reeves, Ward, and Winkler. Figure 2.1.1 shows the existing and planned 345-kV system map of the study area.

Number	Transmission Bus Name
1	Odessa EHV
2	Moss
3	Sand Lake
4	Riverton
5	Solstice
6	Bakersfield
7	North McCamey
8	Big Hill
9	Clearfork
10	Bearkat
11	Long Draw
12	Faraday
13	Scurry County
14	Tonkawa
15	Morgan Creek
16	Longshore
17	Falcon Seaboard
18	Midland

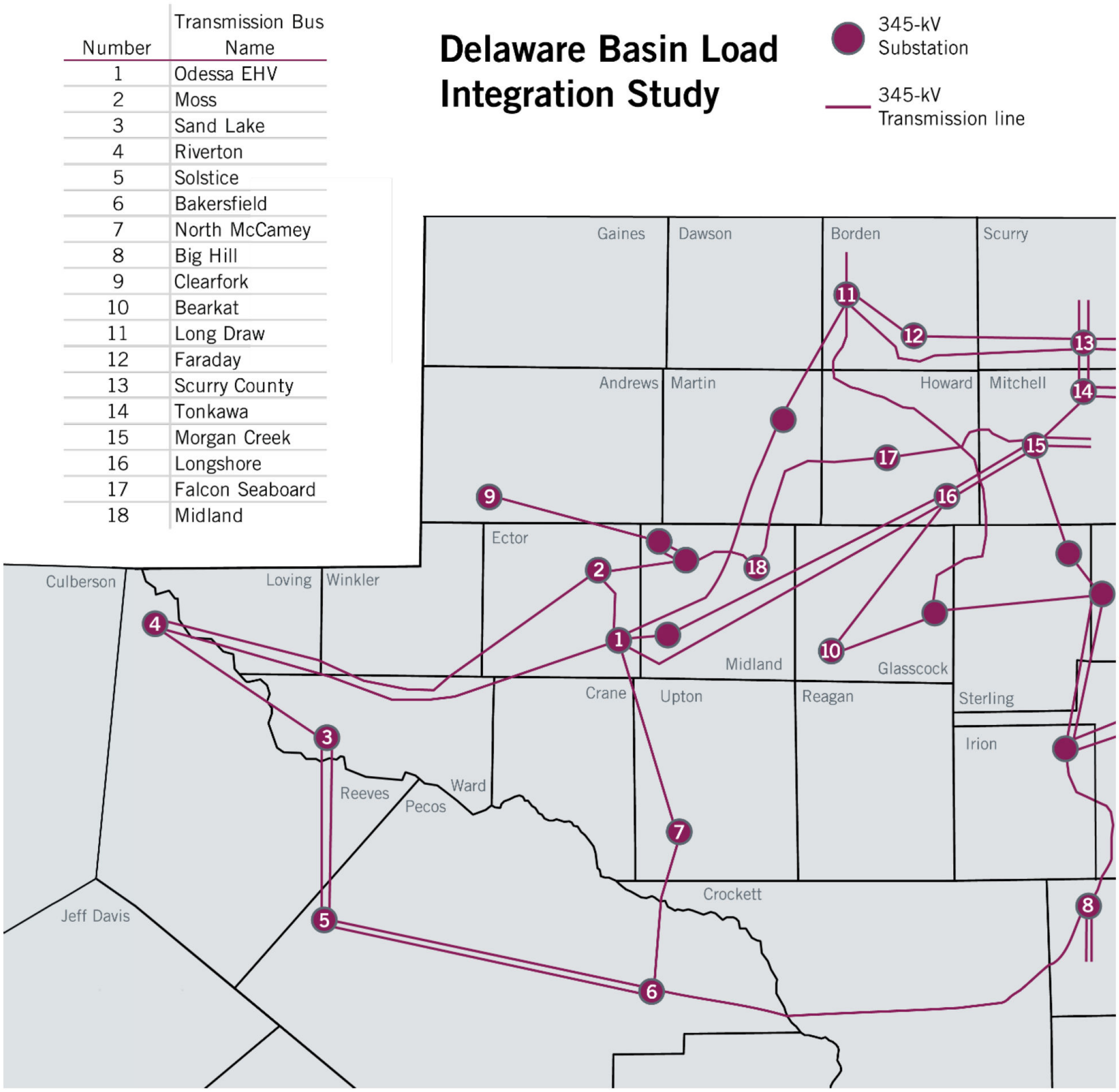

Figure 2.1.1 345-kV Transmission System Map of Study Area

The criteria applied for the AC power flow analyses were consistent with the requirements in the ERCOT Planning Guide 4.1.1.2 and the 2019 Regional Transmission Plan (RTP). As the main purpose of the study is to identify long lead time transmission improvements necessary to serve the assumed load in the study area, ERCOT mainly addressed identified transmission system thermal violations and steady state voltage stability issues in the Far West Weather Zone.

2.2. Study Assumption

2.2.1. Reliability Case

The following starting case was used in the study:

- The 2024 West/Far West (WFW) summer peak case from the 2018 RTP (posted in December 2018 on the ERCOT MIS site)

2.2.2. Study Case Loads

Initially, the Delaware Basin area loads in the starting case (i.e. 2018 RTP 2024 WFW case) were updated to match the area load with the load level (3,509 MW) in the February 2019 SSWG 2024 Summer Peak case as a significant amount of conceptual loads had already been added by TSPs to the Delaware Basin area in the February 2019 SSWG case.

Additionally, the Delaware Basin area loads were further updated by incorporating 1,863 MW of additional conceptual loads provided by the area TSPs (i.e. Oncor, AEP, TNMP, LCRA TSC, and GSEC) based on surveys of their high-use oil and gas customers to support this Delaware Basin Load Integration Study. The customers in the area supplied aggregated load information pertaining to size, schedule, type, and location for the year 2024 by assuming that there would be no capacity or schedule impediments to access electric service in the Delaware Basin. According to the TSPs, the types of the loads in the survey responses included, but were not limited to, the following: planned or projected new load, existing or new load with technology changes (e.g. conversion from self-serve generation to grid power), and load associated with uncompleted oil wells. The load survey samples included large customers that are expected to have a better load projection process and larger impact compared to smaller customers. ERCOT did not extrapolate the load levels provided by TSPs to attempt to account for the smaller customers that were not part of the survey. Using the aggregated load information from their customers, the TSPs established the 1,863 MW of additional conceptual loads projected for the year 2024.

As shown in Table 2.2.1, the load level modeled in this Delaware Basin Load Integration Study was approximately double the load in the same study area compared to the 2019 RTP.

Table 2.2.1 Delaware Basin Load Projection for Year 2024

2019 Regional Transmission Plan (based on Planning Guide Section 3.1.7)	2,688 MW
2019 February SSWG Case	3,509 MW
Delaware Basin Study (including higher than committed load)	5,372 MW

Figures 2.2.1 shows the distribution of the additional conceptual loads added to the study case in the Delaware Basin area.

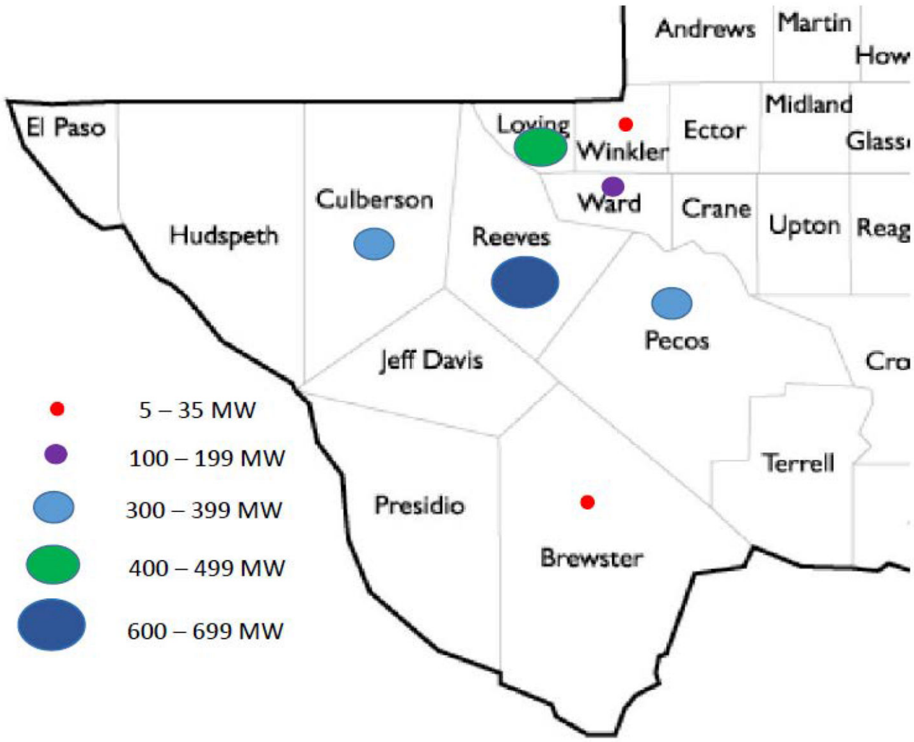

Figure 2.2.1 Distribution of Conceptual Loads Added to the System in the Delaware Basin Area

Figure 2.2.2 shows the load contour map of the total load in Delaware Basin area.

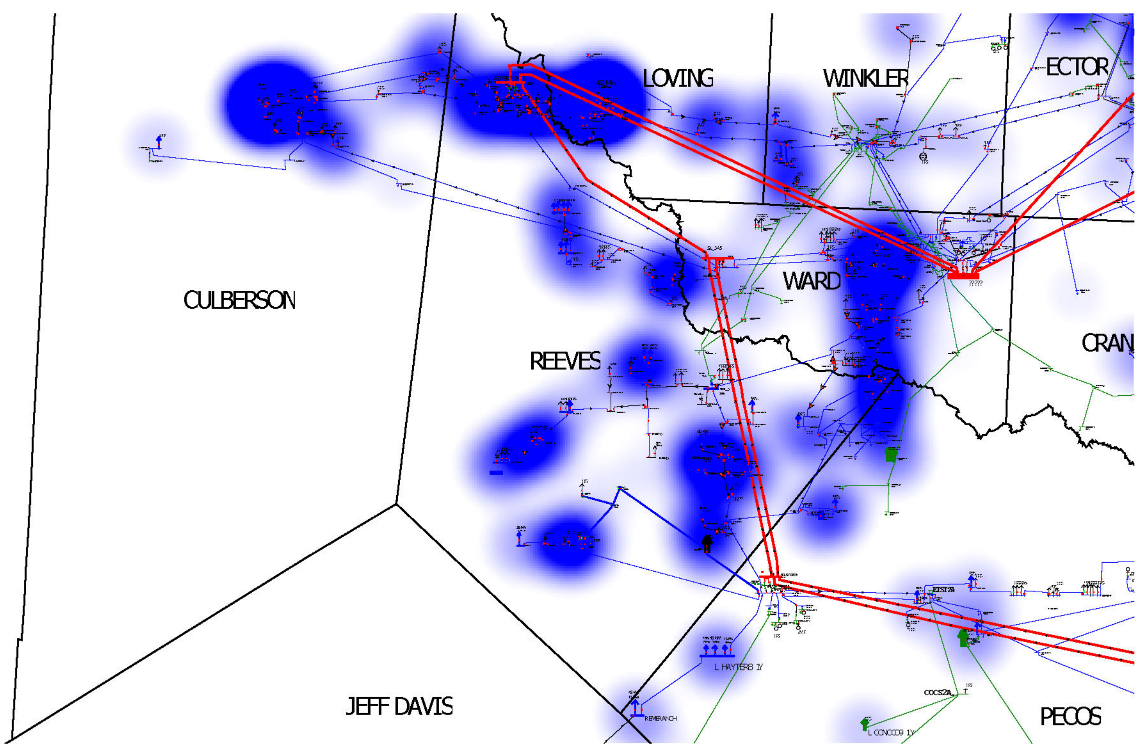

Figure 2.2.2 Load Contour Map of the Total Load in the Delaware Basin Area

2.2.3. Transmission Topology

The starting case was modified based on input from TSPs to include load additions and topological changes in the study area. TSPs provided upgrades and new circuits (if there were no existing transmission facilities in the area) necessary to interconnect the conceptual load additions.

2.2.4. Generation

Planned generators in the West and Far West weather zones that met Planning Guide Section 6.9 conditions for inclusion in the base cases (according to the 2019 April Generation Interconnection Status report) were added to the study case. The added generators are listed in Table 2.2.2.

Table 2.2.2 Added Generators that Met Planning Guide Section 6.9 Conditions (2019 April GIS Report)

GINR Number	Project Name	MW	Fuel	County	Weather Zone
16INR0019	BlueBell Solar	30	SOL	Coke	West
17INR0067	Sweetwater 1 repower	0	WIN	Nolan	West
17INR0068	Sweetwater 2 repower	7	WIN	Nolan	West
17INR0069	Trent repower	6	WIN	Nolan	West
18INR0033	Oveja Wind	300	WIN	Irion	West
18INR0038	Barrow Ranch	160	WIN	Andrews	Far West
18INR0068	Loraine Windpark Phase III	100	WIN	Mitchell	West
19INR0029	Phoebe Solar	250	SOL	Winkler	Far West
19INR0083	Oberon Solar	180	SOL	Ector	Far West
19INR0099a	Kontiki 1 Wind (ERIK)	255	WIN	Glasscock	Far West
19INR0099b	Kontiki 2 Wind (ERNEST)	255	WIN	Glasscock	Far West
19INR0174	Elbow Creek repower	0	WIN	Howard	Far West
19INR0184	Oxy Solar	16	SOL	Ector	Far West
20INR0011	Ranchero Wind	300	WIN	Crockett	Far West
14INR0009	WKN Amadeus Wind	246	WIN	Fisher	West
18INR0055	Long Draw Solar	225	SOL	Borden	Far West
19INR0038	High Lonesome W	450	WIN	Crockett	Far West
19INR0080	Whitehorse Wind	419	WIN	Fisher	West
19INR0102	Queen Solar	400	SOL	Upton	Far West
19INR0163	Sage Draw Wind	338	WIN	Lynn	Far West
19INR0185	Lapetus Solar 2	100	SOL	Andrews	Far West
20INR0054	Taygete Solar	254	SOL	Pecos	Far West

Solar generation in the Delaware Basin area was turned off to represent a stressed system condition since the oil and natural gas loads are assumed to operate as constant loads throughout the day and night. The dispatch of solar and wind generation outside of the Delaware Basin area were consistent with the 2019 RTP methodology. Gibbons Creek Unit 1 (470 MW) was turned off as it was retired permanently in October 2019.

2.2.5. Capital Cost Estimates

Capital costs estimates of each transmission upgrade identified were provided by the TSP relevant to each upgrade. ERCOT used the cost estimates provided by the TSPs to calculate total project cost estimates for various project options. For new transmission lines requiring new right of way, ERCOT assumed a routing adder of 20% to the straight distance between two end points. The cost estimates described in this report only include the capital costs of the 345-kV transmission upgrades.

2.3. Study Methodology

ERCOT evaluated various types of transmission upgrades such as adding long lead time extra high voltage (EHV) transmission lines (e.g. new 345-kV lines) and new 138-kV lines. Table 2.3.1 shows the types of upgrades considered in this study.

Table 2.3.1 Types of Upgrades Considered in this Study

Types of Upgrades Considered	Comments
Long lead time Extra High Voltage circuits (e.g. new 345-kV lines)	**Main focus of the study**
Existing 345-kV line upgrades	Included in the analysis
New 138-kV lines	Included in the analysis, but not optimized
Existing 138-kV and 69-kV line upgrades	Included in the analysis, but not optimized
Voltage support devices, static and dynamic	Included in the analysis, but stability analysis was not performed to optimize

The graphic in Figure 2.3.1 shows the study process and methodology used in this study.

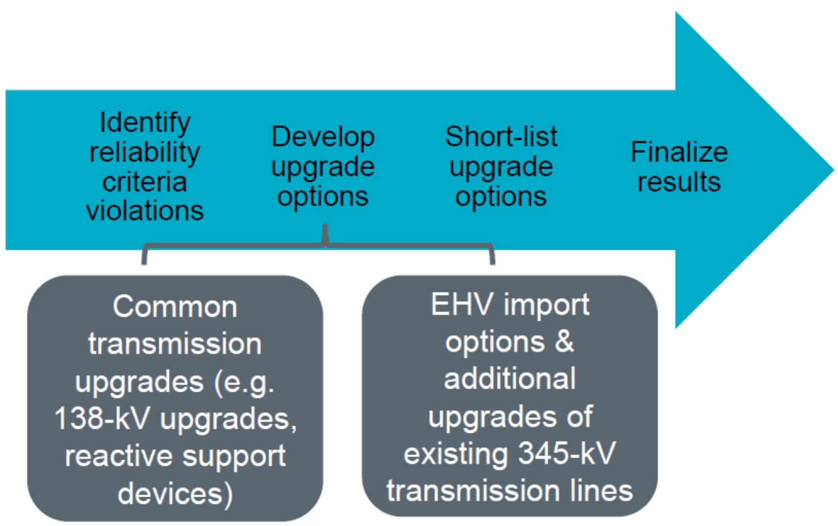

Figure 2.3.1 Study Process and Methodology

2.3.1. Tools

ERCOT utilized the following software tools for the Delaware Basin Load Integration Study:

- PowerWorld Simulator version 20 was used for SCOPF and steady state contingency and voltage stability analysis
- UPLAN version 10.4.0.22733 was used to perform security-constrained economic analysis

2.3.2. Contingencies

All of the NERC P1, P2-1, and P7 contingencies in the West and Far West weather zones were evaluated for the AC power flow analyses. ERCOT also evaluated G-1+N-1 and X-1+N-1 contingencies in the study area.

For the G-1+N-1 analyses, the following generator outages were considered to represent the most significant G-1 conditions in the study area:

- Permian Basin all five units (340 MW)
- Odessa Combined Cycle Train 1 (497 MW)

For the X-1+N-1 analyses, the following 345/138-kV transformers were considered to represent the most significant X-1 conditions for the study area:

- Riverton 345/138-kV transformer 1
- Sand Lake 345/138-kV transformer 1
- Wolf 345/138-kV transformer 1
- Quarry Field 345/138-kV transformer 1
- Solstice 345/138-kV transformer 1
- Megan 345/138-kV transformer 1

The oil and gas loads were assumed to be constant loads throughout the year. Because of this, it can be challenging to schedule maintenance outages of equipment without operating in a state such that the contingency of another facility causes thermal or voltage limit exceedances. To give due consideration for such operational flexibility and reliability in the study area, potential high impact maintenance outages which include major single-circuit 345-kV circuit and dynamic reactive devices in the Delaware Basin area were analyzed and are listed below.

- Odessa - Wolf 345-kV line
- Wolf - Quarry Field 345-kV circuit 1
- Faraday - Clearfork 345-kV circuit 1 (potential new line)
- Clearfork - Riverton 345-kV circuit 1 (potential new line)
- Bearkat - North McCamey 345-kV circuit 1 (potential new line)
- North McCamey - Megan 345-kV circuit 1 (potential new line)
- North McCamey - Sand Lake 345-kV circuit 1 (potential new line)
- Riverton - Sand Lake 345-kV circuit 1
- Solstice - Megan 345-kV circuit 1
- Megan - Sand Lake 345-kV circuit 1
- Bakersfield - Solstice 345-kV circuit 1
- Noelke - Bakersfield 345-kV line

- Queen Solar - North McCamey 345-kV line
- Rando DRD (250 Mvar)
- Horse Shoe DRD (250 Mvar)
- IH-20 SVC (190 Mvar)

3. Case Development for Long Lead Time Upgrade Identification

The existing and planned transmission system was not sufficient to serve the studied load of 5,372 MW in the Delaware Basin area. In fact, the study case demonstrated voltage instability under N-0 conditions. To identify the long lead time upgrades, which were the primary focus of the study, the reliability issues under N-0 that would be expected to be addressed through local transmission upgrades were first identified through the steps described in Appendix A. These transmission upgrades, summarized in Table 3.1, were necessary to address the voltage instability and thermal violations under N-0 condition. ERCOT also identified local transmission upgrades under N-1 in section 4. These transmission upgrades under N-0 and N-1 were collectively referred to as the common transmission upgrades. The full list of the common transmission upgrades is included in the Appendix B.

Table 3.1 Common Transmission Upgrades under N-0

Transmission Upgrades/Addition	Length (miles)	Normal and Emergency Ratings (RATE A/B) (MVA) Modeled in Study Case
Tap the new 345-kV Wolf station to the Odessa/Moss – Riverton 345-kV double-circuit lines and add two 345/138-kV transformers at Wolf station (TPIT 46094, Tier 3, Dec 2020)		750/750 (transformer Ratings)
Reactive device at Clearfork		300 Mvar
Reactive device at Riverton		300 Mvar
Reactive device at Wolf		300 Mvar
Reactive device at Barilla Draw		300 Mvar
Reactive device at Faulkner		300 Mvar
Reactive device at Coalson Draw (DRD)		250 Mvar
Capacitors at Owl Hills		110 Mvar
Convert 69-kV line Barrilla - Hoefs Road - Verhalen - Saragosa to 138-kV	33.8	483/483
Convert 69-kV line Yucca - Royalty - Coyanosa - Wolfcamp to 138-kV	46.9	614/614
Tap the Wolf - Riverton 345-kV double circuit at Quarry Field, and add two 345/138-kV transformer at Quarry Field station		750/750 (transformer Ratings)
Upgrade Quail Switch - Odessa EHV Switch 345-kV ckt 1	0.9	1521/1784
Upgrade the Solstice - Hayter - Remeranch 138-kV	15.7	614/614

Besides the common transmission upgrades, a placeholder project of a new single circuit 345-kV import path (Bearkat - Wolf - Sand Lake) was also added in the case development to address the voltage instability under N-0. This placeholder project will be evaluated and replaced by alternatives in section 4.

4. Initial Import Path Options

The study case development in Section 3 indicated that a new import path was needed to serve the assumed Delaware Basin load with solar generation offline in the area. ERCOT initially evaluated various import path options and the study results are summarized in this section.

4.1. Descriptions of the Initial Import Path Options

An initial set of import path options was developed by considering the following factors in the area: reliability criteria violations in the study case, potential generating capacity growth, the existing stability constraints (maintained in operations as Generic Transmission Constraints (GTCs)) in the region, and the ERCOT 2018 Long-Term System Assessment[2]. Table 4.1.1 summarizes the initial import path options. The maps of these ten initial Import path options are available in Appendix C.

Table 4.1.1 Descriptions of the Initial Import Options

Import Options	Estimated New Right of Way (ROW) (miles)	Cost Estimates ($M)
Option 1: add a second circuit on the existing Big Hill - Bakersfield - North McCamey - Odessa 345-kV line and a new North McCamey - Megan double circuit 345-kV line	78	311
Option 2: a new Faraday - Lamesa - Clearfork - Riverton single circuit 345-kV line	193	380
Option 3: a new Bearkat - North McCamey - Megan single circuit 345-kV line	149	278
Option 4: a new Faraday - Lamesa - Clearfork - Riverton double circuit 345-kV line	193	444
Option 5: a new Bearkat - North McCamey - Megan double circuit 345-kV line	149	343
Option 6: a new Bearkat - North McCamey - Sand Lake double circuit 345-kV circuit	164	371
Option 7: a new Red Creek - North McCamey - Megan double circuit 345-kV circuit	216	490
Option 8: a new 1,200 MW HVDC line (VSC) from Abernathy to Riverton	240	906
Option 9: a new 1,200 MW HVDC line (VSC) from Howard Road to Bakersfield and a new double circuit 345-kV line from North McCamey to Megan	380	2,119
Option 10: a new single circuit 765-kV line from Howard Road to Bakersfield, two new 765/345-kV transformers at both Howard Road and Bakersfield stations, and a new double circuit 345-kV line from North McCamey to Megan	380	2,014

[2] https://mis.ercot.com/pps/tibco/mis/Pages/Grid+Information/Long+Term+Planning/

4.2. Results of Reliability Analysis for the Initial Import Path Options

4.2.1. Results of N-1 contingency analysis

Among the initial ten options evaluated, ERCOT found that five options did not meet the N-1 reliability criteria. The results of the study showed unsolved contingencies (i.e. potential voltage collapse) for Options 1, 2, 3, 7, and 8 at the assumed load of 5,372 MW in Delaware Basin area, and these five options alone were not evaluated further but were combined with other import path options for further evaluation.

Steady state voltage stability assessment under N-1 contingency conditions was conducted to estimate the load serving capability of the ten initial import path options and the results are summarized in Table 4.2.1. As an estimate, the load serving capability of each option was calculated by a 100 MW step change based on the assumed load of 5,372 MW under P1, P2-1, and P7 contingency events.

Table 4.2.1 Estimated Load Serving Capability of Ten Initial Import Options (NERC P1, P2-1 and P7)

Import Options	Estimated New ROW (miles)	Estimated Load Serving Capability (MW)
Option 1: add a second circuit on the existing Big Hill - Bakersfield - North McCamey - Odessa 345-kV line and a new North McCamey - Megan double circuit 345-kV line	78	~ 4,972
Option 2: a new Faraday - Lamesa - Clearfork - Riverton single circuit 345-kV line	193	~ 4,972
Option 3: a new Bearkat - North McCamey - Megan single circuit 345-kV line	149	~ 4,972
Option 4: a new Faraday - Lamesa - Clearfork - Riverton double circuit 345-kV line	193	~ 5,372
Option 5: a new Bearkat - North McCamey - Megan double circuit 345-kV line	149	~ 5,372
Option 6: a new Bearkat - North McCamey - Sand Lake double circuit 345-kV circuit	164	~ 5,372
Option 7: a new Red Creek - North McCamey - Megan double circuit 345-kV circuit	216	~ 5,272
Option 8: a new 1,200 MW HVDC line (VSC) from Abernathy to Riverton	240	~ 5,272
Option 9: a new 1,200 MW HVDC line (VSC) from Howard Road to Bakersfield and a new double circuit 345-kV line from North McCamey to Megan	380	~ 5,472
Option 10: a new single circuit 765-kV line from Howard Road to Bakersfield, two new 765/345-kV transformers at both Howard Road and Bakersfield stations, and a new double circuit 345-kV line from North McCamey to Megan	380	~ 5,472

The results in Table 4.2.1 show that Options 4, 5, 6, 9, and 10 are capable of serving the assumed Delaware Basin load under N-1 conditions without voltage instability, and additional local transmission upgrades are needed to address the local N-1 steady state reliability criteria violations. These additional local transmission upgrades are listed in Table 4.2.2. As shown in the table, most of the upgrades are needed to serve the local load independent of the import options. The full list of the transmission upgrades are available in Appendix B.

Table 4.2.2 Additional Local Transmission Upgrades in the Initial Import Path Options

Transmission Upgrades	Estimated Length (miles)	Normal and Emergency Ratings (RATE A/B) (MVA) Modeled in Study Case	Import Options Requiring Local Upgrades
Build a new 345/138-kV Owl Hills station with two 345/138-kV transformers, and add a new single circuit 345-kV line from Riverton to Owl Hills station	20.3	750/750 (transformer Ratings) 2988/2988 (Line Ratings)	Common[3]
Tap the new Megan station to the Solstice - Sand Lake double circuit 345-kV line, and install two new 345/138-kV transformers at the new Megan station		750/750 (transformer Ratings)	Common
Build a new 138-kV line from Saragosa to Faulkner	18.0	614/614	Common
Rio Pecos to Fort Stockton Upgrade: Upgrade the 138-kV lines from Rio Pecos to Lynx to TNMP 16th St to Fort Stockton	74.6	483/483	Common
Convert the existing stations at Fort Stockton and Conoco Comp and Conoco Rgec 69-kV line to be 138-kV. Move the 138/69-kV transformer from Fort Stockton to Conoco Comp	25.1	614/614	Common
Build a new 138-kV line from Conoco Rgec to TNMP 16th street	22.0	483/483	Common
Build a new 138-kV line from Remeranch to Saragosa	26.5	483/483	Common
Upgrade the existing Morgan Creek - Tonkawa 345-kV line	21.3	1792/1792	Common
Upgrade the existing Morgan Creek - Longshore 345-kV line	36.5	1792/1792	Options 5 & 6
Upgrade the existing Midland East - Falcon Seaboard 345-kV line	48.4	1792/1792	Common
Upgrade the existing Saddleback - Salt Draw Tap 138-kV line	0.5	717/717	Option 5
Upgrade the existing Salt Draw Tap - IH20 138-kV line	4.9	717/717	Option 5
Build a new double circuit 138-kV line from the new Megan station to Saddleback	6.2	614/614	Common
Build a new double circuit 138-kV line from the new Megan station to Faulkner	24.2	614/614	Common
Upgrade the existing Morgan Creek - Falcon Seaboard 345-kV line	36.2	1792/1792	Options 9 & 10
Upgrade the existing Longshore - Midessa 345-kV line	48.0	1792/1792	Options 9 & 10
Upgrade the existing Midland East - Midland County NW 345-kV line	17.2	1792/1792	Option 10

[3] Common means the project is needed regardless of import options

4.2.2. Results of G-1+N-1, X-1+N-1, and N-1-1 contingency analysis

Import Options 4, 5, 6, 9, and 10 were further evaluated for G-1+N-1, X-1+N-1, and N-1-1. Tables 4.2.3 – 4.2.5 show the study results.

Table 4.2.3 Steady State Voltage Stability Analysis Results under G-1+N-1 for Options 4, 5, 6, 9, and 10

G-1 Scenario	Option 4	Option 5	Option 6	Option 9	Option 10
Permian Basin all five units	Voltage Collapse	Voltage Collapse	Voltage Collapse	Voltage Collapse	Voltage Collapse
Odessa Combined Cycle Train 1	No Voltage Collapse	No Voltage Collapse	No Voltage Collapse	No Voltage Collapse	No Voltage Collapse

Table 4.2.4 Largest Thermal Violations under X-1+N-1 for Options 4, 5, 6, 9, and 10

Element	Contingency	Option 4	Option 5	Option 6	Option 9	Option 10
Quarry Field 345/138-kV	Riverton - Quarry Field 345-kV double; Quarry Field 345/138-kV	< 100%	108.5%	104.7%	109.8%	108.2%
Riverton 345/138-kV	Owl Hill - Riverton 345-kV; Riverton 345/138-kV	100.4%	< 100%	< 100%	< 100%	< 100%
Megan 345/138-kV	Megan - Sand Lake 345-kV double; Megan 345/138-kV	< 100%	118.7%	< 100%	119.0%	120.7%
Wolf 345/138-kV	Wolf - Quarry Field 345-kV double; Wolf 345/138-kV	< 100%	107.8%	105.4%	111.0%	107.0%

Table 4.2.5 Steady State Voltage Stability Analysis Results under N-1-1 for Options 4, 5, 6, 9, and 10

	Option 4	Option 5	Option 6	Option 9	Option 10
N-1-1 Scenario	Voltage Collapse	Voltage Collapse	Voltage Collapse	Voltage Collapse	Voltage Collapse

As shown in Table 4.2.3 and Table 4.2.5, potential voltage collapse issues were observed for all five options under the G-1+N-1 and N-1-1 contingency conditions. As described in section 5, ERCOT further modified these import options to identify the additional upgrade needs to serve the assumed load in the Delaware Basin area. Option 10 which requires a new 765-kV line was not selected for the further evaluation as substantial new transmission additions will be required to satisfy the reliability criteria under the N-1-1 maintenance condition.

5. Modified Import Options

5.1. Description of the Modified Import Options

Twelve ERCOT modified Import Options based on the selected Import Options 4, 5, 6, and 9 and some of the transmission components in the initial ten import path options were developed to address the G-1+N-1 and N-1-1 reliability violations. These modified import options are referred as Options 4a, 4b, 4c, 4g, 5d, 5e, 5f, 6a, 6e, 6f, 6g, and 9e. Table 5.1.1 summarizes these twelve modified import options. The maps of these twelve options are provided in the Appendix B.

Table 5.1.1 Summary of the Twelve Modified Import Options

Options	Estimated New ROW (miles)	Cost Estimates[4] ($M)
Option 4a: a new Faraday - Lamesa - Clearfork - Riverton double circuit 345-kV line, and add a second circuit on the existing Big Hill - Bakersfield - North McCamey -Odessa 345-kV line	193	573
Option 4b: a new Faraday - Lamesa - Clearfork - Riverton double circuit 345-kV line, add a second circuit on the existing Big Hill - Bakersfield 345-kV line, and a new North McCamey - Megan double circuit 345-kV line	271	695
Option 4c: a new Faraday - Lamesa - Clearfork - Riverton double circuit 345-kV line and a new Bearkat - North McCamey - Megan single circuit 345-kV line	342	722
Option 4g: a new Faraday - Lamesa - Clearfork - Riverton double circuit 345-kV line, add a second circuit on the existing Big Hill - Bakersfield 345-kV line, convert the Sand Lake - Riverton 138-kV to 345-kV, and add a new 138-kV line from Sand Lake to Riverton	193	569
Option 5d: a new Bearkat - North McCamey - Megan double circuit 345-kV line, and a new Clearfork - Riverton double circuit 345-kV line	231	525
Option 5e: a new Bearkat - North McCamey - Megan double circuit 345-kV line, add a second circuit on the existing Big Hill - Bakersfield 345-kV line, and a new Clearfork - Riverton double circuit 345-kV line	231	594
Option 5f: a new Bearkat - North McCamey - Megan double circuit 345-kV line, and a new Faraday - Lamesa - Clearfork - Riverton single circuit 345-kV line	342	723
Option 6a: a new Bearkat - North McCamey - Sand Lake double circuit 345-kV line, and add a second circuit on the existing Big Hill - Bakersfield - North McCamey - Odessa 345-kV line	164	440
Option 6e: a new Bearkat - North McCamey - Sand Lake double circuit 345-kV line, add a second circuit on the existing the Big Hill - Bakersfield 345-kV line, and a new Clearfork - Riverton double circuit 345-kV line	246	622
Option 6f: a new Bearkat - North McCamey - Sand Lake double circuit 345-kV line, and a new Faraday - Lamesa - Clearfork - Riverton single 345-kV line	357	751
Option 6g: a new Bearkat - North McCamey - Sand Lake double circuit 345-kV line, add a second circuit on the existing Big Hill - Bakersfield 345-	164	496

[4] Cost estimates do not include the local transmission upgrades.

kV line, convert the Sand Lake - Riverton 138-kV to 345-kV, and add a new 138-kV line from Sand Lake to Riverton		
Option 9e: add a new 1,200 MW HVDC line (VSC) from Howard Road to Bakersfield, a new North McCamey - Megan double circuit 345-kV line, add a second circuit on the existing Big Hill - Bakersfield 345-kV line, and a new Clearfork - Riverton double circuit 345-kV line	462	2,370

5.2. Results of Reliability Analysis for the Modified Import Options

ERCOT conducted the N-1-1 analysis for these twelve options. Table 5.2.1 shows the study results.

Table 5.2.1 Steady State N-1-1 Results for Options 4a, 4b, 4c, 4g, 5d, 5e, 5f, 6a, 6e, 6f, 6g, and 9e

Option 4a	Option 4b	Option 4c	Option 4g	Option 5d	Option 5e	Option 5f	Option 6a	Option 6e	Option 6f	Option 6g	Option 9e
Voltage Collapse	No Voltage Collapse	No Voltage Collapse	Voltage Collapse	Voltage Collapse	No Voltage Collapse	No Voltage Collapse	Voltage Collapse	No Voltage Collapse	No Voltage Collapse	No Voltage Collapse	No Voltage Collapse

Voltage collapse issues were observed in Options 4a, 4g, 5d, and 6a under the N-1-1 contingency condition. As a result, ERCOT performed additional studies for Options 4b, 4c, 5e, 5f, 6e, 6f, 6g, and 9e as no voltage collapses were observed under the N-1-1 contingency condition. Focusing on thermal violations, ERCOT evaluated these eight options under the N-1-1, X-1+N-1 and G-1+N-1 conditions. The results are summarized in Tables 5.2.2 – 5.2.4.

Table 5.2.2 Largest Thermal Violations under N-1-1 for Options 4b, 4c, 5e, 5f, 6e, 6f, 6g and 9e

Element	Miles	Option 4b	Option 4c	Option 5e	Option 5f	Option 6e	Option 6f	Option 6g	Option 9e
Morgan Creek - Falcon Seaboard 345-kV	36.2	< 100%	< 100%	105.0%	101.0%	104.0%	< 100%	< 100%	< 100%
Telephone Road - Clearfork 345-kV	32.8	< 100%	< 100%	103.6%	< 100%	102.7%	< 100%	< 100%	< 100%
Midland East - Midland County NW 345-kV	17.2	< 100%	< 100%	100.3%	< 100%	< 100%	< 100%	< 100%	103.3%
Odessa - Wolf 138-kV	44.4	< 100%	< 100%	< 100%	102.4%	< 100%	< 100%	107.6%	< 100%

Table 5.2.3 Largest Thermal Violations under X-1+N-1 for Options 4b, 4c, 5e, 5f, 6e, 6f, 6g, and 9e

Element	Option 4b	Option 4c	Option 5e	Option 5f	Option 6e	Option 6f	Option 6g	Option 9e
Quarry Field 345/138-kV	< 100%	< 100%	< 100%	< 100%	< 100%	< 100%	< 100%	< 100%
Riverton 345/138-kV	< 100%	< 100%	< 100%	< 100%	< 100%	< 100%	< 100%	< 100%
Megan 345/138-kV	< 100%	< 100%	114.2%	< 100%	< 100%	< 100%	< 100%	116.5%
Wolf 345/138-kV	< 100%	< 100%	< 100%	< 100%	< 100%	< 100%	< 100%	< 100%

Table 5.2.4 Largest Thermal Violations under G-1+N-1 for Options 4b, 4c, 5e, 5f, 6e, 6f, 6g, and 9e

Element	Option 4b	Option 4c	Option 5e	Option 5f	Option 6e	Option 6f	Option 6g	Option 9e
Morgan Creek - Falcon Seaboard 345-kV	< 100%	< 100%	103.3%	< 100%	103.0%	< 100%	< 100%	< 100%
Telephone Road - Clearfork 345-kV	< 100%	< 100%	< 100%	< 100%	< 100%	< 100%	< 100%	102.6%
Odessa - Wolf 138-kV	< 100%	< 100%	< 100%	< 100%	< 100%	< 100%	108.4%	< 100%

The N-1-1, G-1+N-1, and X-1+N-1 study results in Tables 5.2.2 – 5.2.4 indicate that Options 4b, 4c, 6f, and 6g performed the best among the options tested. There are no additional 345-kV thermal violations for Options 4b, 4c, 6f, and 6g under the N-1-1, G-1+N-1, or X-1+N-1 contingency conditions. Since the overload of the existing Odessa - Wolf 138-kV line was identified under N-1-1 condition in Option 6g, ERCOT included the upgrade of the overload existing 138-kV line as part of Option 6g during the further evaluation of the selected four short-listed options.

6. Short-listed Options

The results of the N-1-1, G-1+N-1, and X-1+N-1 analyses in Section 5 indicate that Options 4b, 4c, 6f, and 6g would provide the best performance among the eight selected modified options. For these four short-listed options, ERCOT conducted power transfer analysis, congestion analysis, and cost comparison.

6.1. Power Transfer Analysis

A power transfer analysis was conducted from a steady state voltage stability perspective for the four short-listed options. The load in the Delaware Basin area was proportionally increased, and NERC P1, P2-1, and P7 contingency events in the study area were tested to identify estimated maximum load serving capability. The results are listed in Table 6.1.1; all four short-listed options would be capable of serving a load level above the assumed Delaware Basin load.

Table 6.1.1 Power Transfer Analysis for Options 4b, 4c, 6f, and 6g

Option	Estimated New ROW (miles)	Estimated N-1 Load Serving Capability (MW)
4b	291	5,982
4c	362	6,062
6f	378	6,042
6g	185	5,772

6.2. Congestion Analysis

Although the Delaware Basin Load Integration Study was focused on reliability needs, ERCOT also conducted a congestion analysis to compare the relative performance of each of the short-listed options in terms of production cost savings.

The 2024 economic case built for the 2019 RTP was used as the starting case. The common 345-kV transmission upgrades together with the recently approved RPG projects in the Delaware Basin area were added to the starting case to create the study base case. The load in the congestion analysis remained the same as in the 2019 RTP. ERCOT then modeled each of the four short-listed import options and performed production cost simulations for the year 2024. The annual production cost under each select option was compared to the option yielding the highest annual production cost in order to obtain a relative annual production cost difference for each option.

As shown in Table 6.2.1, the results indicated that the annual production cost differences for Options 4b, 4c, and 6f were approximately \$0.4 million, \$3.1 million, and \$3.1 million, respectively, when compared to Option 6g. The results indicated none of the options provided significantly better production cost savings than others. The study also indicated no significant change in system congestion on the ERCOT transmission grid for each short-listed option.

Table 6.2.1 Relative Annual Production Cost Differences (Referenced to Option 6g) in \$ Million

Option	Option 4b	Option 4c	Option 6f	Option 6g
Relative Annual Production Cost Differences (referenced to Option 6g)	0.4	3.1	3.1	Reference

6.3. Cost Estimates

All four short-listed import options require some additional existing 345-kV transmission line upgrades. The cost estimate of each short-listed import option in Table 6.3 also includes the cost of upgrading the existing 345-kV lines. Since the main focus of this study was to identify cost-effective long lead time transmission improvements to reliably serve the assumed load, the costs of the transmission upgrades with voltage 138-kV and below were not considered in the cost comparison. Table 6.3.1 summarizes the cost estimates for the four short-listed options. Note all values are rough order magnitude (ROM) quality estimates and do not include uncertain factors that may be revealed during a more detailed routing study/CCN-level cost estimate (e.g. environmental/cultural components, etc.)

Table 6.3.1 Cost Estimates for the Short-Listed Options in $ Million

Option	Transmission Element	Cost Estimate ($M)	Total Cost Estimates ($M)
4b	A new Faraday - Lamesa - Clearfork - Riverton double circuit 345-kV line	444	753
	Add a 2nd circuit on the existing Big Hill - Bakersfield 345-kV line	69	
	A new North McCamey - Megan double circuit 345-kV line	182	
	A new Riverton - Owl Hills single circuit 345-kV line	41	
	Upgrade the existing 345-kV lines from Quail Switch to Odessa and from Morgan Creek to Tonkawa	17	
4c	A new Faraday - Lamesa - Clearfork - Riverton double circuit 345-kV line	444	816
	A new Bearkat - North McCamey - Sand Lake double circuit 345-kV line	278	
	A new Riverton - Owl Hills single circuit 345-kV line	41	
	Upgrade the existing 345-kV lines from Quail Switch to Odessa, from Morgan Creek to Tonkawa, and from Midland to Falcon Seaboard	53	
6f	A new Bearkat - North McCamey - Sand Lake double circuit 345-kV line	371	873
	A new Faraday - Lamesa - Clearfork - Riverton single circuit 345-kV line	380	
	A new Riverton - Owl Hills single circuit 345-kV line	41	
	Upgrade the existing 345-kV lines from Quail Switch to Odessa, from Morgan Creek to Tonkawa, from Midland to Falcon Seaboard, and from Morgan Creek to Longshore	81	
6g	A new Bearkat - North McCamey - Sand Lake double circuit 345-kV line	371	618
	Add a 2nd circuit on the existing Big Hill - Bakersfield 345-kV line	69	
	Sand Lake - Riverton 138-kV to 345-kV conversion and a new Sand Lake - Riverton 138-kV line	56	
	A new Riverton - Owl Hills single circuit 345-kV line	41	
	Upgrade the existing 345-kV lines from Quail Switch to Odessa, from Morgan Creek to Tonkawa, from Midland to Falcon Seaboard, and from Morgan Creek to Longshore	81	

7. Roadmap of Long Lead Time Upgrades

Based on the study results of the four short-listed import options described in Section 6 and the consideration of uncertainty of conceptual load growth in the Delaware Basin area, ERCOT developed a roadmap identifying different upgrade stages to accommodate the load growth in the Delaware Basin area. The transmission upgrades at each stage in the roadmap only include the long lead time transmission improvements (new 345-kV lines). As the upgrades of the existing 345-kV lines can be implemented in a relatively short time frame, they were not included in the roadmap development. The common 138-kV transmission upgrades and the reactive devices were also assumed to be in-service prior to Stage 1 to serve the local loads in the area.

Figure 7.1 shows the triggers of the transmission upgrades at each stage in terms of the load level in the Delaware Basin area. Table 7.1 lists the details of the transmission additions associated with each stage in the developed roadmap. The triggers and limits are based on either thermal or steady state voltage stability under the N-1, G-1+N-1, X-1+N-1, and N-1-1 contingency conditions.

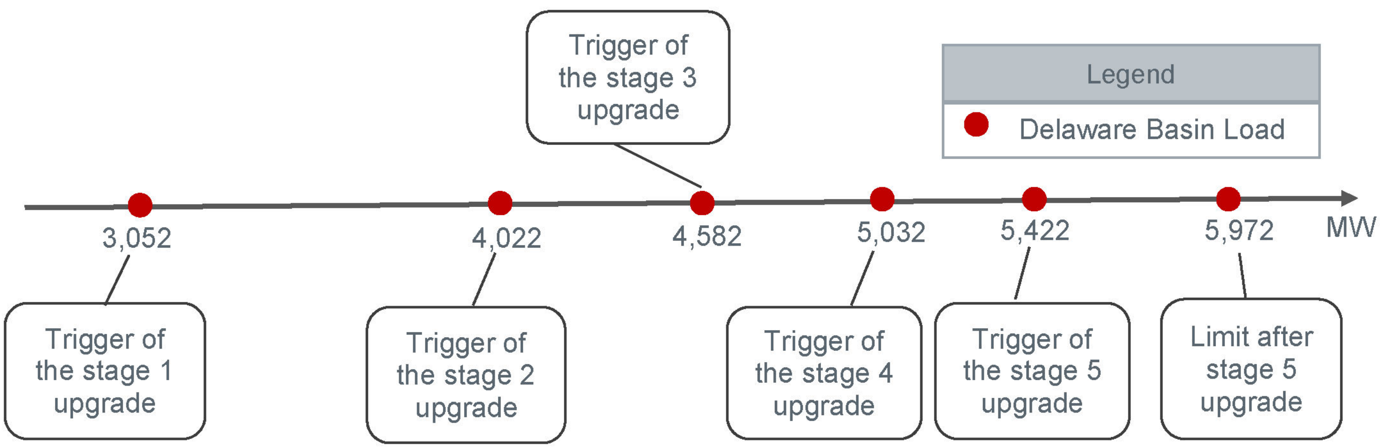

Figure 7.1 Delaware Basin Transmission Upgrade Roadmap

Table 7.1 Delaware Basin Transmission Upgrade Roadmap – Detailed Project List

Stage	Estimated Delaware Basin Load Level (MW)	Upgrade Element	Estimated Upgrade Cost ($M)	Trigger
1	3,052	Add a second circuit on the existing Big Hill - Bakersfield 345-kV line	69	Import Needs
2	4,022	A new Bearkat - North McCamey - Sand Lake double circuit 345-kV line	371	Import Needs
3	4,582	A new Riverton - Owl Hills single circuit 345-kV line	41	Culberson Loop Needs
4	5,032	Riverton - Sand Lake 138-kV to 345-kV conversion and a new Riverton - Sand Lake 138-kV line	56	Culberson Loop Needs
5	5,422	A new Faraday - Lamesa - Clearfork - Riverton double circuit 345-kV line	444	Import Needs

Figure 7.2 shows the existing and planned 345-kV system map of the study area together with the Stage 1 – Stage 5 transmission upgrades.

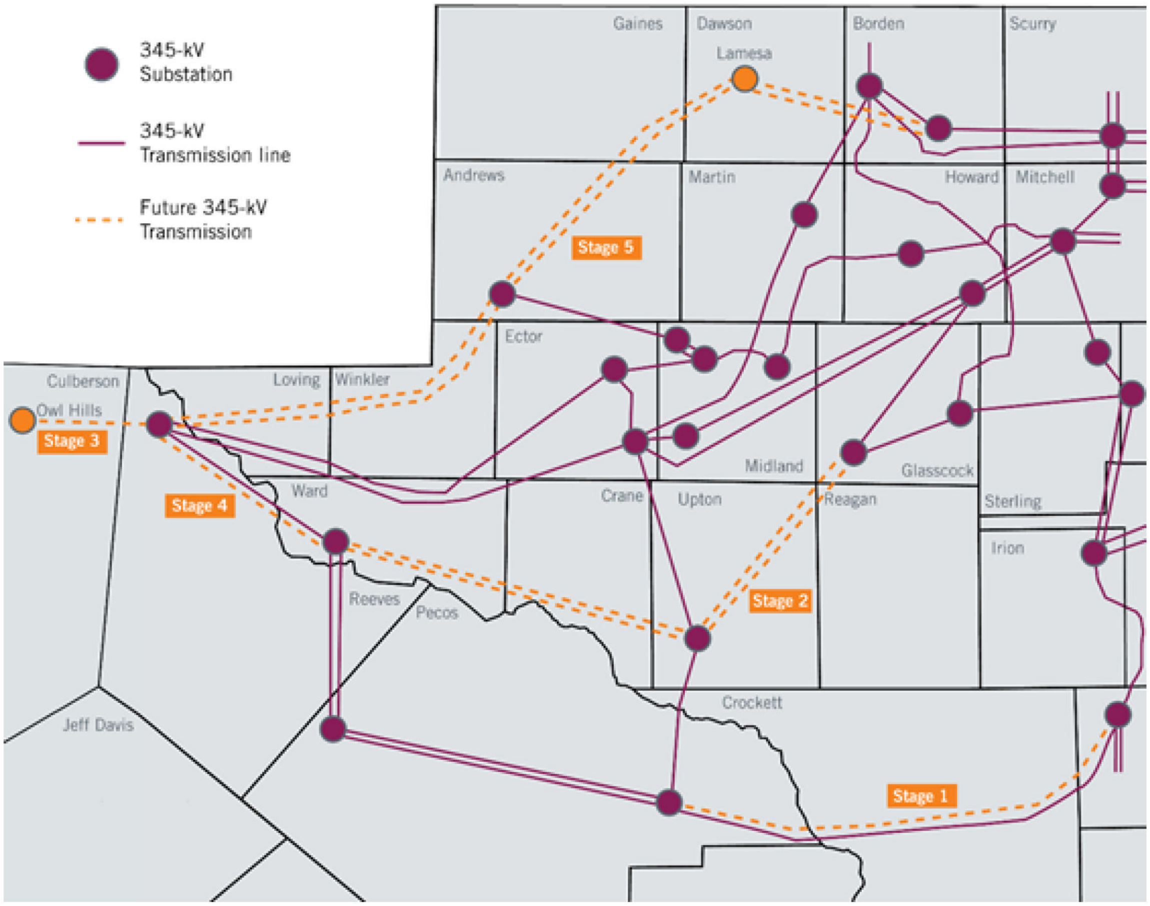

Figure 7.2 345-kV Transmission System Map of Study Area with Stage 1 – Stage 5 Upgrades

Although the study year was 2024, it should not be assumed that all of the improvement projects are needed in 2024. The actual need for each project could be sooner or later than 2024 depending on the growth rate and location of the load in the Delaware Basin. Other factors that could affect the need for and timing of the upgrades include, but are not limited to, common transmission upgrade implementation, availability and dispatch of the generation in the study area, impedance of the new conductors, transmission upgrade cost estimates, and the results of dynamic stability analysis, which was not conducted as part of this study.

7.1. Roadmap – Stage 1 Upgrade

Transmission overload is expected to occur under N-1-1 contingency condition when the Delaware Basin load level reaches 3,052 MW. The addition of the second circuit on the existing Big Hill - Bakersfield 345-kV line was identified as the stage 1 upgrade to address the transmission overload. The cost estimate of the Stage 1 upgrade is $69 million. With the stage 1 upgrade, the load serving capability in the Delaware Basin was estimated to increase to 4,022 MW.

In addition to benefiting the Delaware Basin area, this circuit would be expected to provide stability benefits for the export of wind and solar power out of the McCamey area and West Texas overall. As of November 2019, there were more than 3,500 MWs of generation connected in the Bakersfield and McCamey area, including approximately 2,400 MWs connected directly to the existing Big Hill - Bakersfield 345-kV line. Furthermore, there are existing stability constraints (managed in operations by the Bakersfield GTC and McCamey GTC). The addition of a second circuit on the Big Hill - Bakersfield 345-kV line would improve these stability constraints and lead to less congestion. ERCOT did not quantify these benefits as part of this study.

7.2. Roadmap – Stage 2 Upgrade

When the Delaware Basin load reaches 4,022 MW, additional transmission overload is expected to occur under G-1+N-1 contingency condition, which indicates the need for an additional import path. The addition of a new 345-kV double circuit line from Bearkat to North McCamey to Sand Lake was identified to address the transmission overload. The Stage 2 upgrade is estimated to cost $371 million, requiring approximately 164 miles of new right of way. With the Stage 2 upgrade, the load serving capability in the Delaware Basin area would increase to 4,582 MW.

The addition of a new 345-kV double circuit line from Bearkat to North McCamey to Sand Lake would also improve the existing stability constraints at Bakersfield and McCamey. ERCOT did not quantify these benefits as part of this study.

7.3. Roadmap – Stage 3 and Stage 4 Upgrades

Local voltage collapse issues under N-1 contingency conditions were observed when the area load reached 4,582 MW. The addition of a new 345-kV single circuit line from Riverton to Owl Hills was identified to address this local voltage collapse issue. The Stage 3 upgrade requires approximately 20 miles of new right of way and is estimated to cost $41 million.

When the Delaware Basin load reaches 5,032 MW, a different local voltage collapse was observed under N-1-1 contingency conditions. To address this additional local voltage collapse, ERCOT proposes the Stage 4 upgrade include the conversion of the Riverton - Sand Lake 138-kV line to 345-kV line and the addition of the new 138-kV line from Riverton to Sand Lake to serve the local load. The cost estimate of the Stage 4 upgrade is about $56 million.

The transmission upgrade identified in Stage 3 is to serve the projected load in the Owl Hills area along the Culberson loop. The need of this transmission upgrade is dependent on local load growth. Given the recent rapid load growth in the Owl Hills area, this transmission upgrade may need to be accelerated according to the TSP.

7.4. Roadmap – Stage 5 Upgrade

With the Stage 1 – Stage 4 upgrades assumed in place, the load serving capability in the Delaware Basin was found to increase to 5,422 MW. If the load in the Delaware Basin area reaches to 5,422 MW, another import path will be needed. A new Faraday - Lamesa - Clearfork - Riverton 345-kV double circuit line was identified as a placeholder import path option to further increase the load serving capability. The Stage 5 upgrade requires about 193 miles of new right of way and is estimated to cost $444 million. With the stage 5 upgrade, the load serving capability of the system in the Delaware

Basin area could reach 5,972 MW. The load serving capability may be further improved if additional reactive power support is implemented.

8. Conclusion

The purpose of the Delaware Basin Load Integration Study was to identify potential system constraints and transmission upgrade needs to potentially accommodate significant load growth in the Delaware Basin area. The results provide a roadmap for the long lead time transmission upgrades to the ERCOT stakeholders that include the upgrade needs and the associated triggers in terms of load level in the Delaware Basin area. In addition, a set of transmission upgrades will also be needed to address local issues and load connections in the area.

It should be noted that the identified improvements were based on the assumptions used in the steady state analysis in this study. Should these assumptions change, the results of this analysis will need to be updated which could yield a different set of transmission improvements or trigger points.

Figure 8.1 shows the load comparison of five-year ahead load forecast in the ERCOT SSWG cases and actual historic load in the Delaware Basin area together with the trigger points of the long lead time transmission upgrades identified in the roadmap.

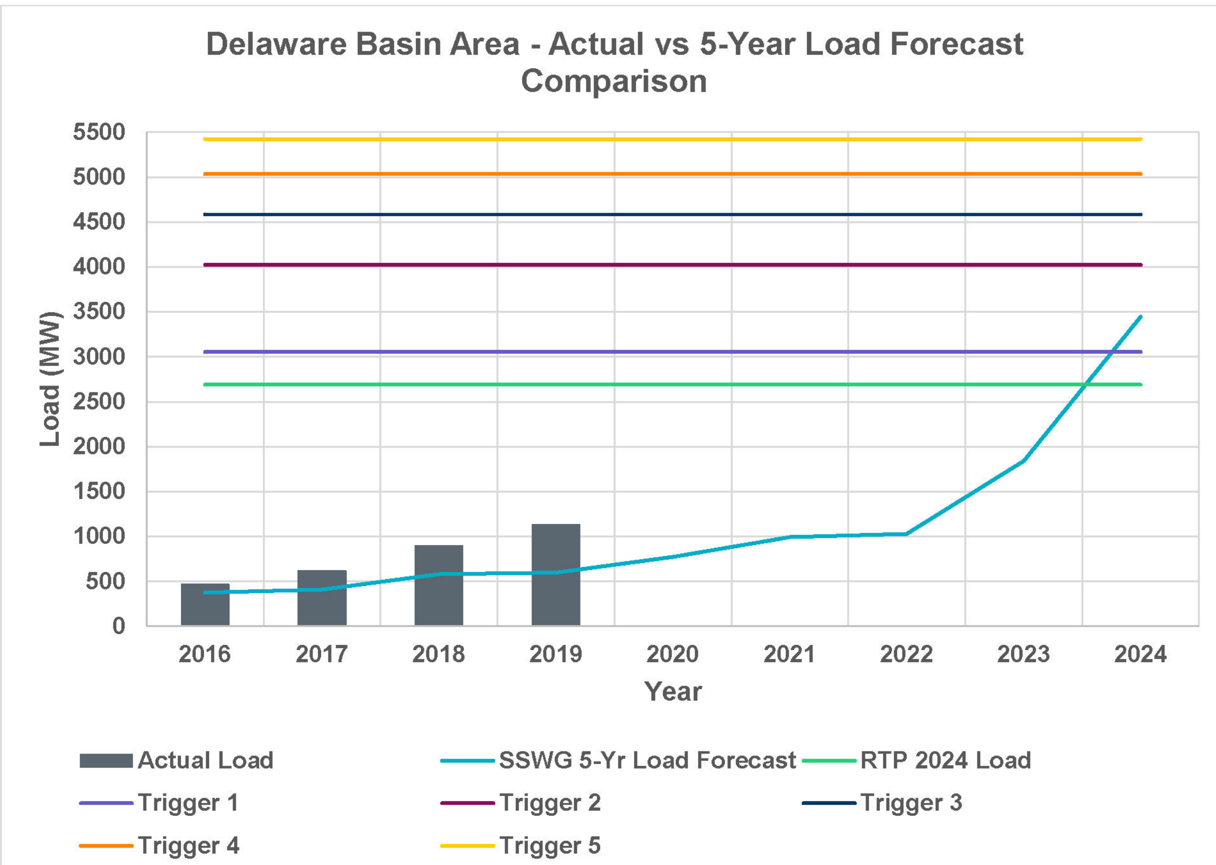

Figure 8.1 Actual and 5-year Load Forecast in the Delaware Basin Area

9. Appendix

9.1. Appendix A: Steps to Develop the Common Upgrades under N-0	Steps to develop the N-0 common up
9.2. Appendix B: List of Upgrades Identified in This Study	TransmissionUpgrades_DelawareBasinS
9.3. Appendix C: Options Diagrams	Appendix - Options Maps_v3.pdf

2023 Regional Transmission Plan

ATTACHMENT NO. 5

Executive Summary

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

6 *Id.*

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

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

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

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

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

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

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1. 2023 Regional Transmission Plan

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

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

1.1. Stakeholder Involvement

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

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

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

1.2. Standards and Regulations

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

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

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

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

1.3. Confidentiality and Report Posting

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

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

2. 2023 Regional Transmission Plan Process

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

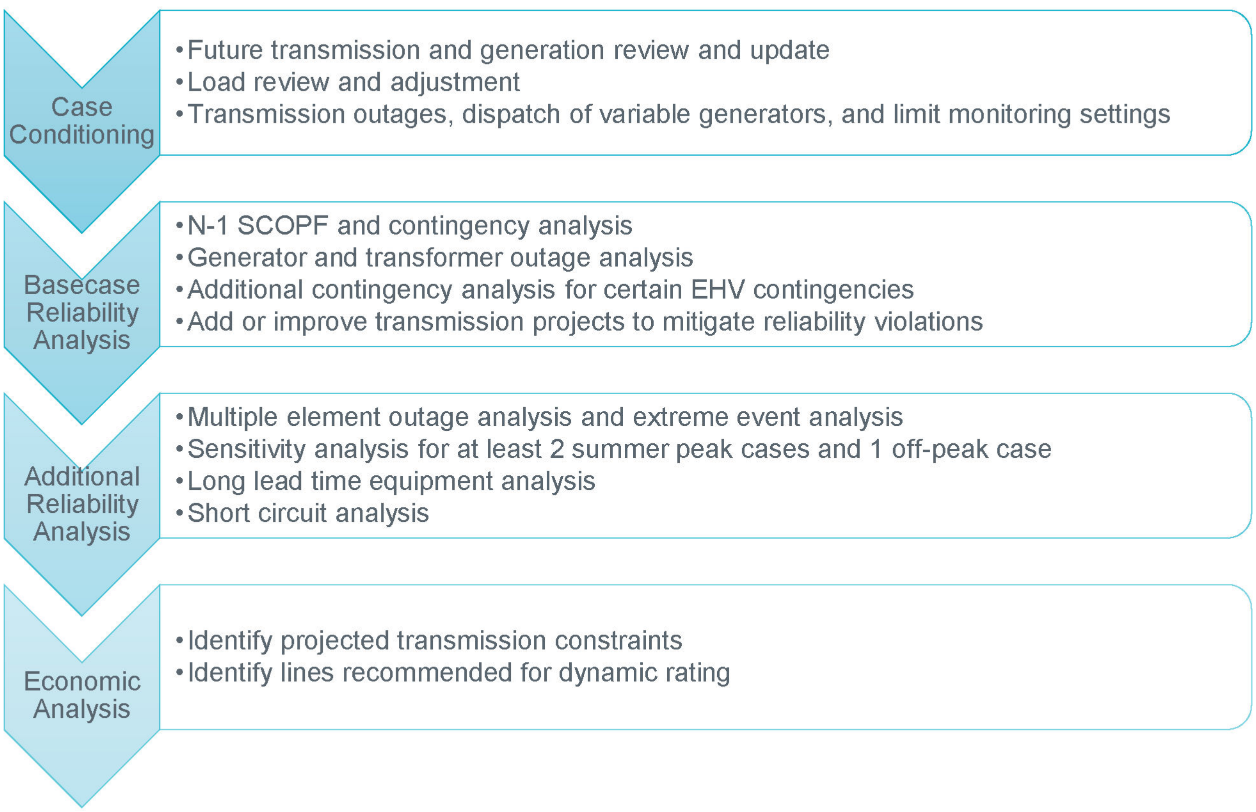

Figure 1: 2023 RTP Transmission Planning Process

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

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

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

2.1. Permian Basin Load Forecast and Large Load Additions

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

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

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

Table 1: Permian Basin Counties

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

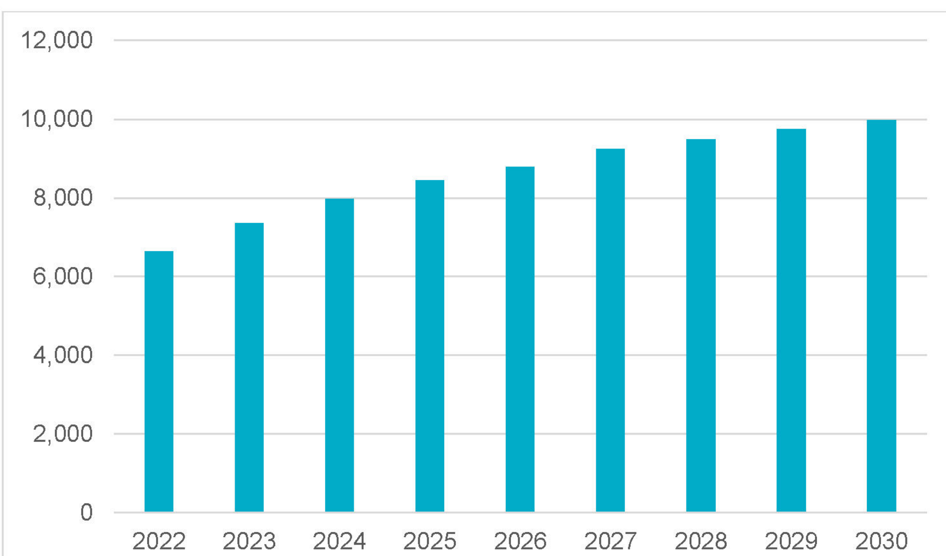

Figure 2: IHS Markit Study Permian Basin Summer Peak Load Forecast (MW)

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

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

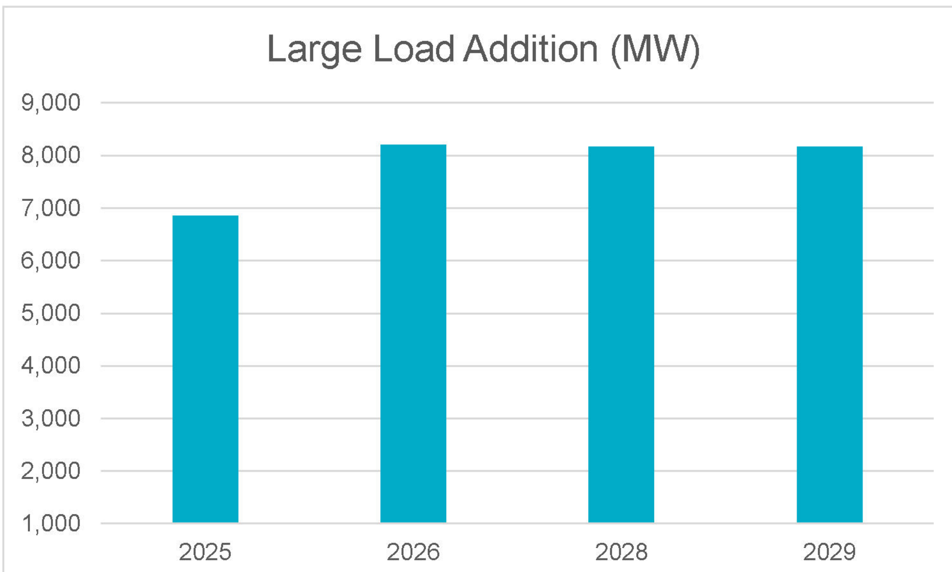

Figure 3: Large Load Addition in 2023 RTP (MW)

2.2. Adoption of the ERCOT Rooftop Solar Growth Forecast

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

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

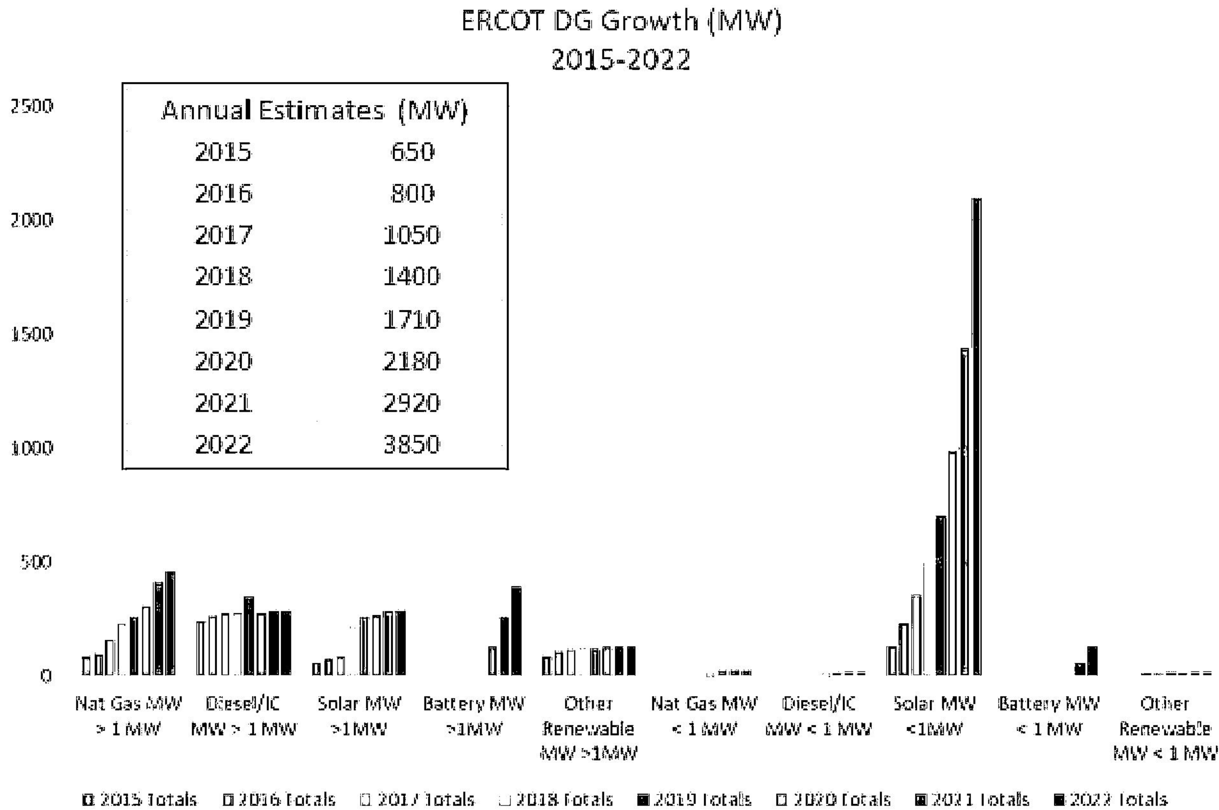

Figure 4: ERCOT Estimated Total DG Growth from 2015 to 2022 (MW)

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

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

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

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

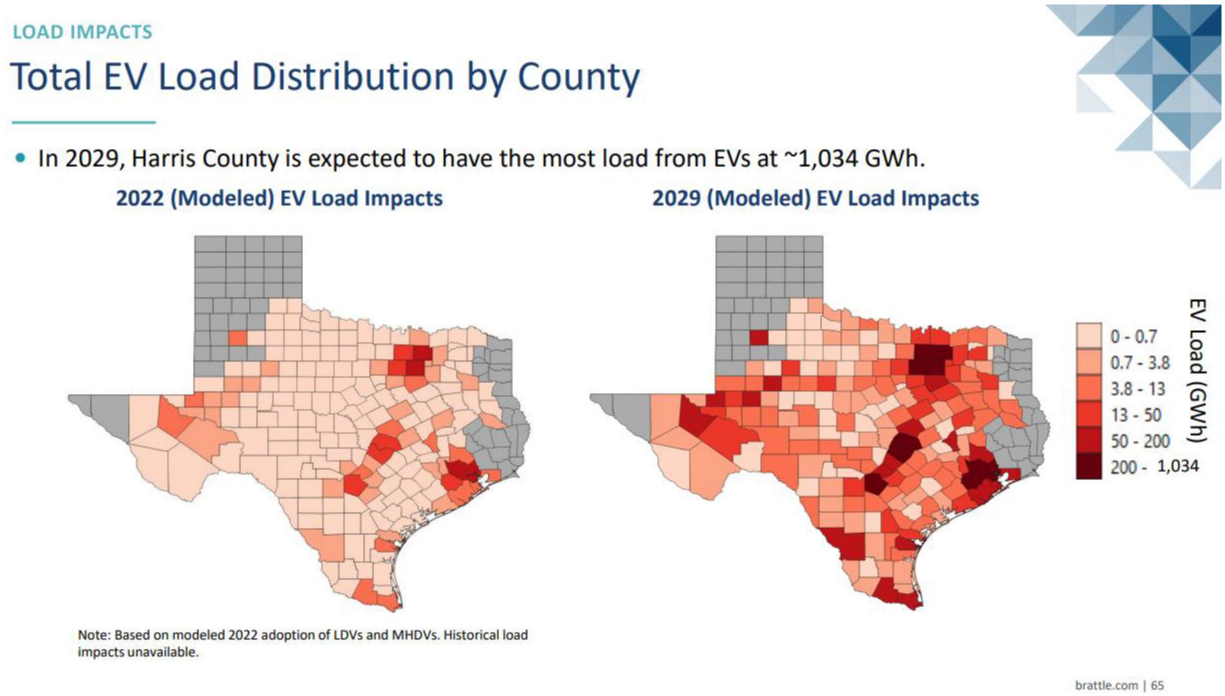

Figure 5: ERCOT Estimated EV Load Distribution by County[11]

2.4. Reliability Analysis

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

The 2023 RTP reliability analysis included the following studies:

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

[11] Ibid.

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

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

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

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

- Known Outages Impact Analysis: Under Requirement 2.1.4 of NERC Reliability Standard TPL-001-5.1, the impact of known outages of generation or transmission facilities planned in the near-term planning horizon was studied. ERCOT issued Market Notices to collect known outages information from both TOs and GOs. TOs were required to provide technical rationales for their known outages selection for each study case included in the 2023 RTP. ERCOT developed the technical rationale[12] for the selection of GO-submitted outages to be included in the corresponding study cases. The known outages from the TOs and the GO outages selected based on ERCOT-developed technical rationale were then used to study their impact on system performance under P0 and P1 contingencies.

- Minimum Deliverability Analysis: As required by ERCOT Planning Guide Section 4.1.1.7, Minimum Deliverability Criteria, ERCOT performed analysis to ensure the deliverability of 100% of capacity of Generation Resources, utilizing combined cycle, steam turbine, combustion turbine, hydro, or reciprocating engine technology, and for any Energy Storage Resource (ESR) with a duration greater than or equal to 2 hours. For ESRs with a duration less than 2 hours, a prorated deliverability was ensured. CAPs were proposed to address any reliability violations under the contingencies defined for the minimum deliverability criteria.

2.4.1 CAP Development

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

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

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

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

2.4.2 System Operating Limit (SOL) Identification

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

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

2.5. Economic Analysis

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

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

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

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

3. Findings from Reliability Analysis

3.1. Reliability Projects and Constraint Management Plans

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

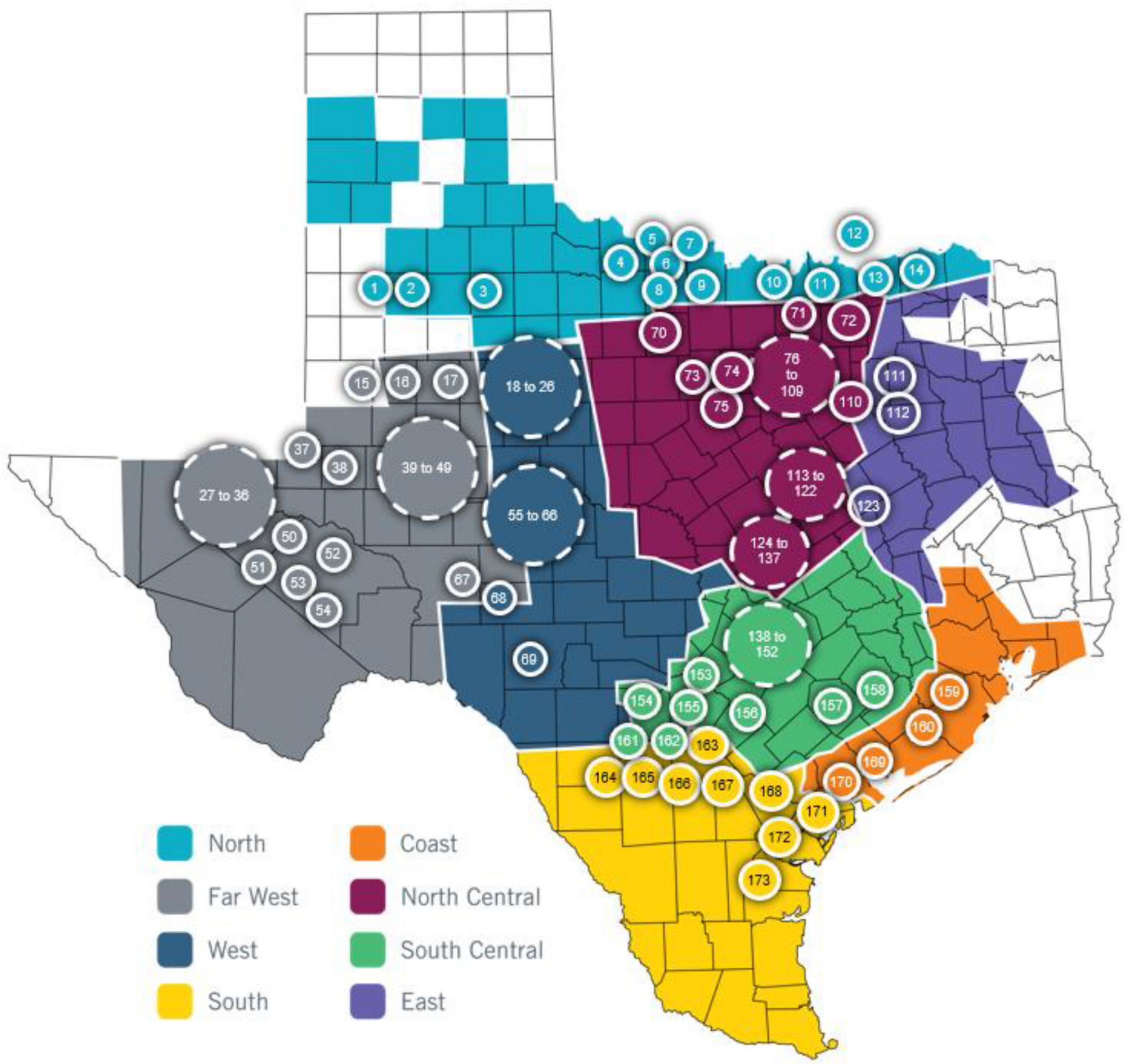

Figure 6: Geographic Locations of CAPs Identified in the 2023 RTP

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

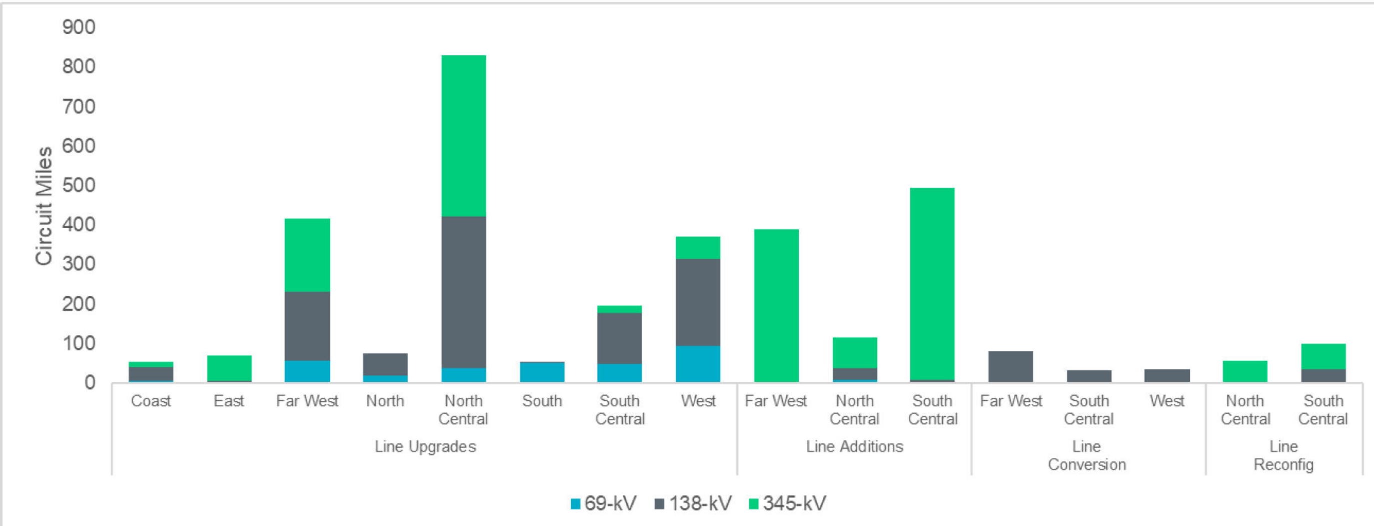

Figure 7: 2023 RTP Transmission Line Project Types by Weather Zone and Voltage Level

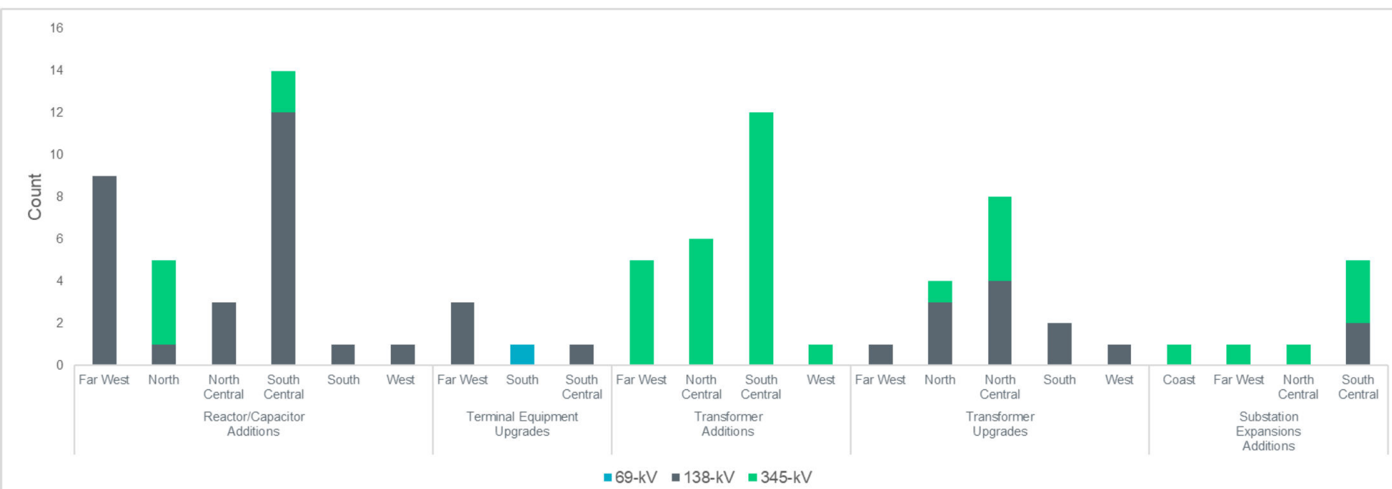

Figure 8: 2023 RTP Other Upgrades and Additions by Weather Zone and Voltage Level

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

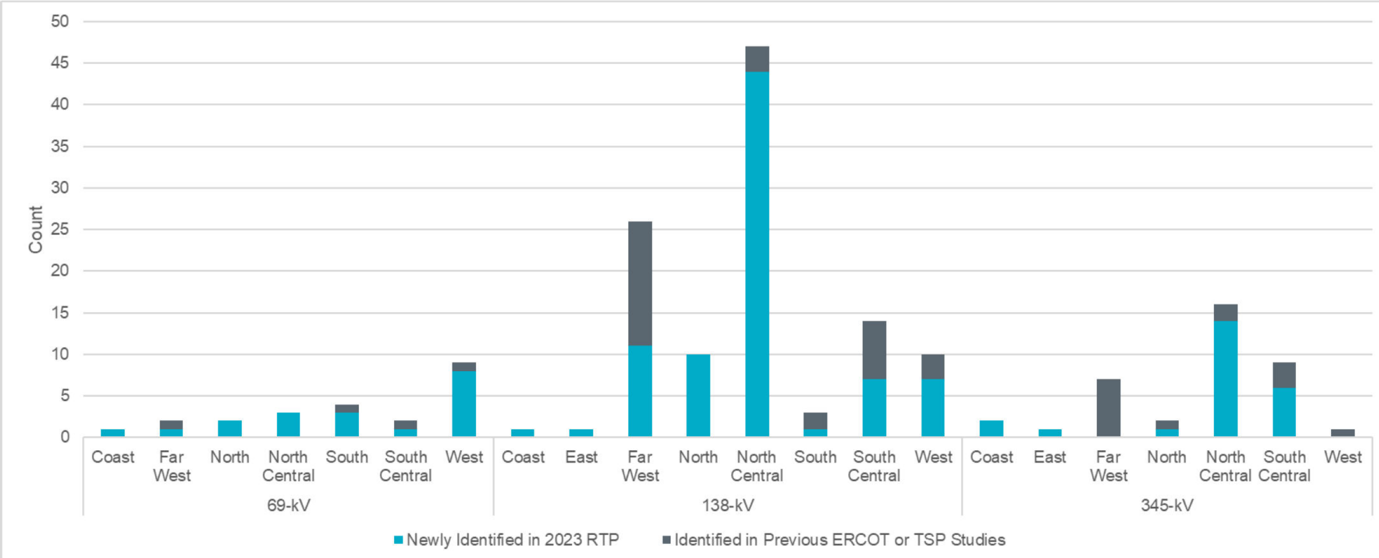

Figure 9: Projects Newly Identified in the 2023 RTP versus Projects Previously Identified

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

3.1.1 West Texas Study Findings

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

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

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

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

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

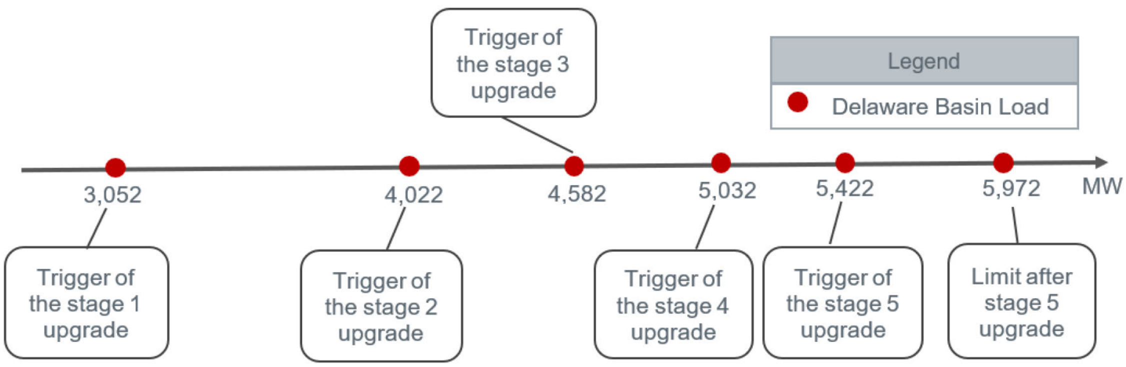

Figure 10: ERCOT Delaware Basin Load Integration Study Road Map

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

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

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

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

3.1.2 Central Texas Study Findings

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

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

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

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

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

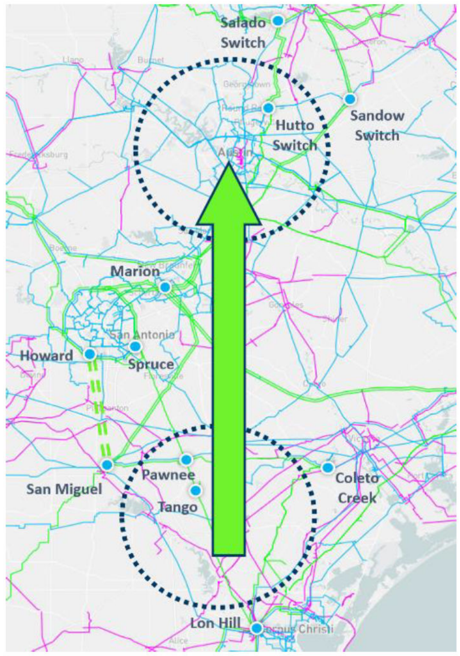

Figure 11: New South to Central Texas Import Path

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

3.1.3 Venus Switch Import Path

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

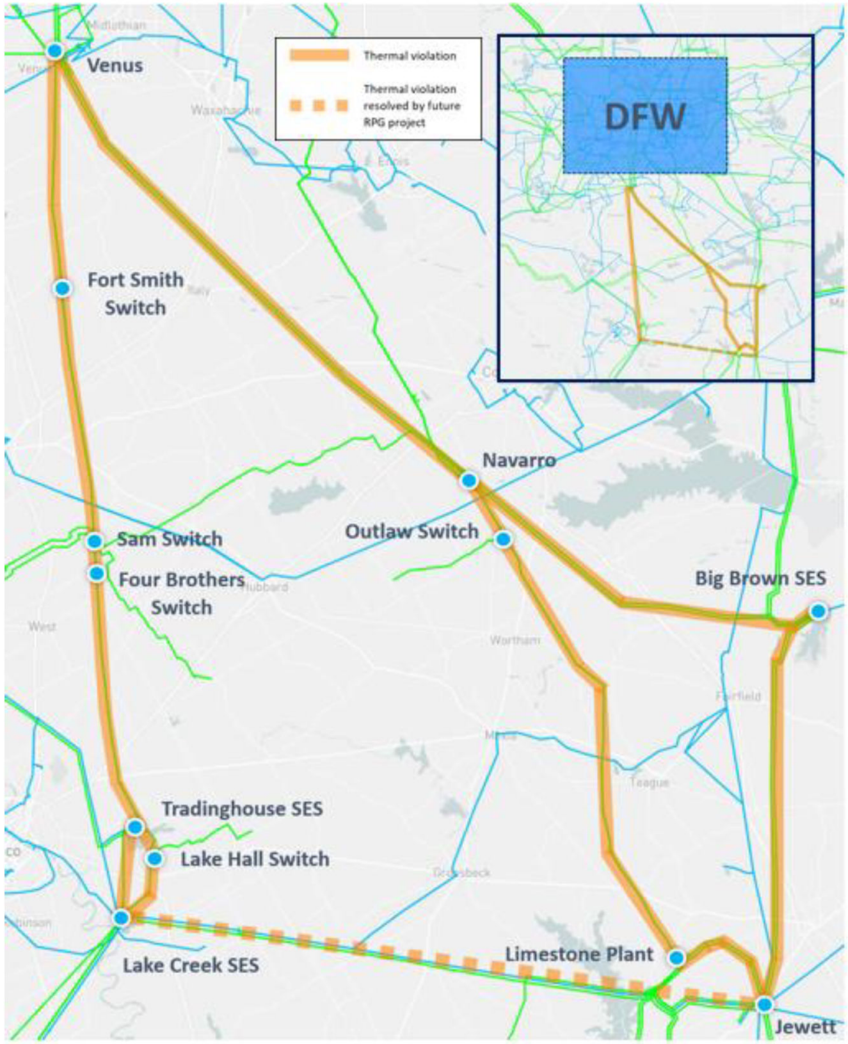

Figure 12: Venus Switch Import Path Reliability Needs

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

3.1.4 Southwest Houston Import Path

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

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

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

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

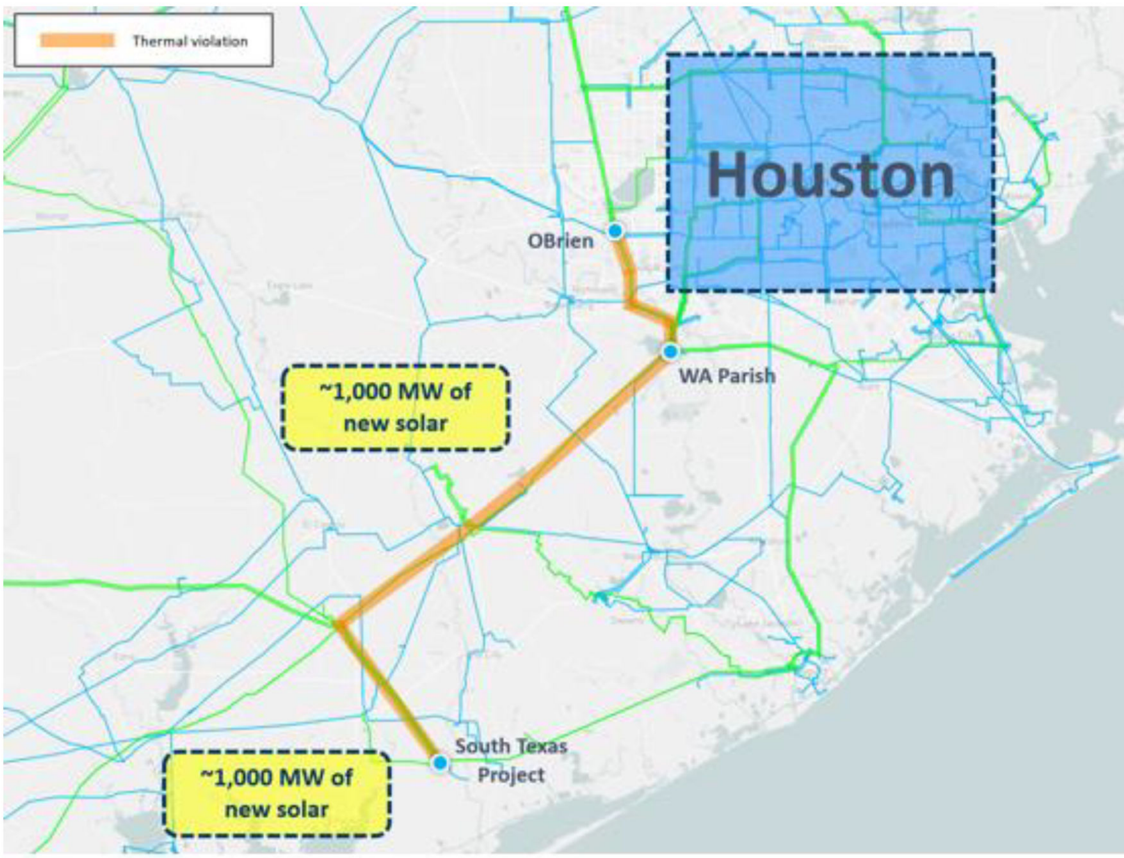

Figure 13: Southwest Houston Import Path Reliability Needs

3.1.5 Other Findings

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

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

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

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

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

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

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

3.2. Sensitivity Analysis

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

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

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

3.2.1 ERCOT Low Solar Summer Net Peak Load Conditions

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

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

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

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

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

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

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

Table 3: Renewable Generation Capacity Factors

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

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

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

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

The detailed results can be found in Appendix K.

3.2.2 High Renewable Light Load Conditions

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

[17] https://www.ercot.com/gridinfo/resource

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

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

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

3.3. Short Circuit Analysis

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

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

Table 4: Summary of Short-circuit Analysis

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

3.4. Long Lead Time Equipment Analysis

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

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

4. Economic Analysis

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

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

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

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

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

[19] All results are based on the 2013 historical weather conditions

[20] Hourly Net Load = Hourly Load Forecast – Hourly Wind Output – Hourly Solar Output

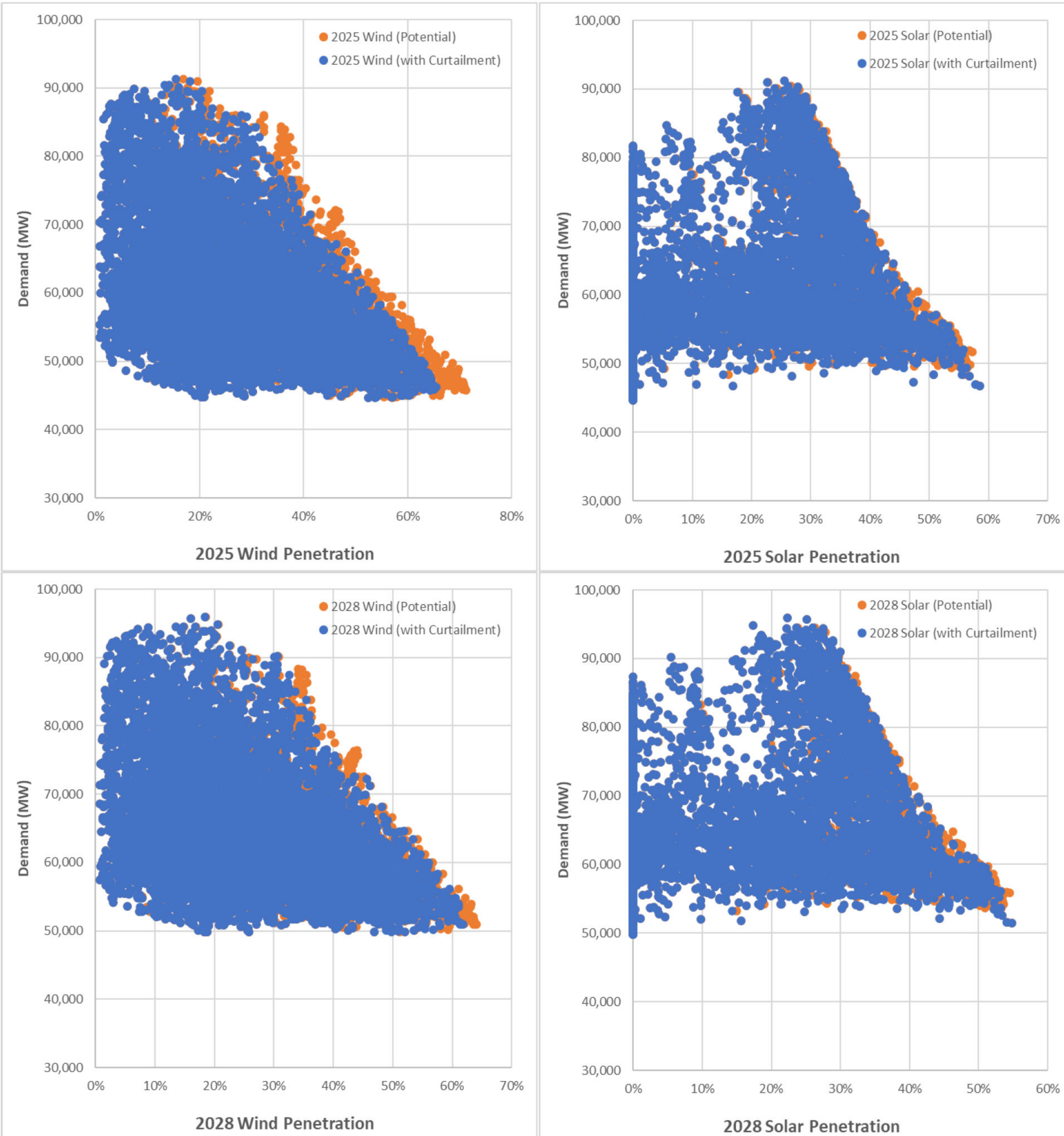

Figure 14: Wind and Solar Penetration

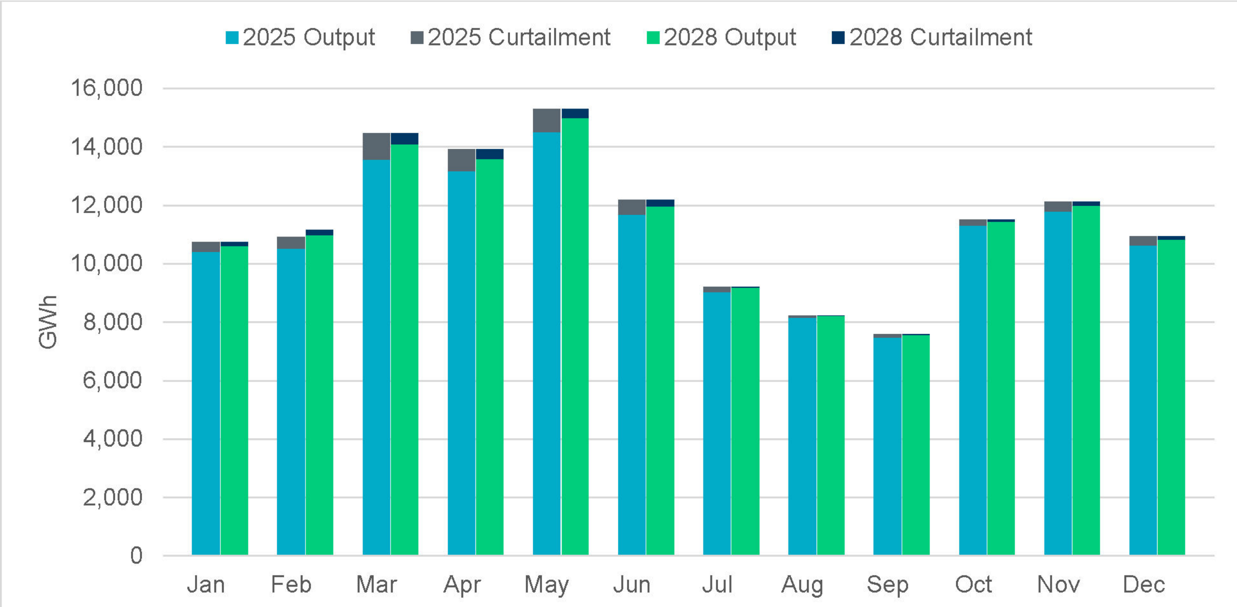

Figure 15: Wind Production and Curtailment

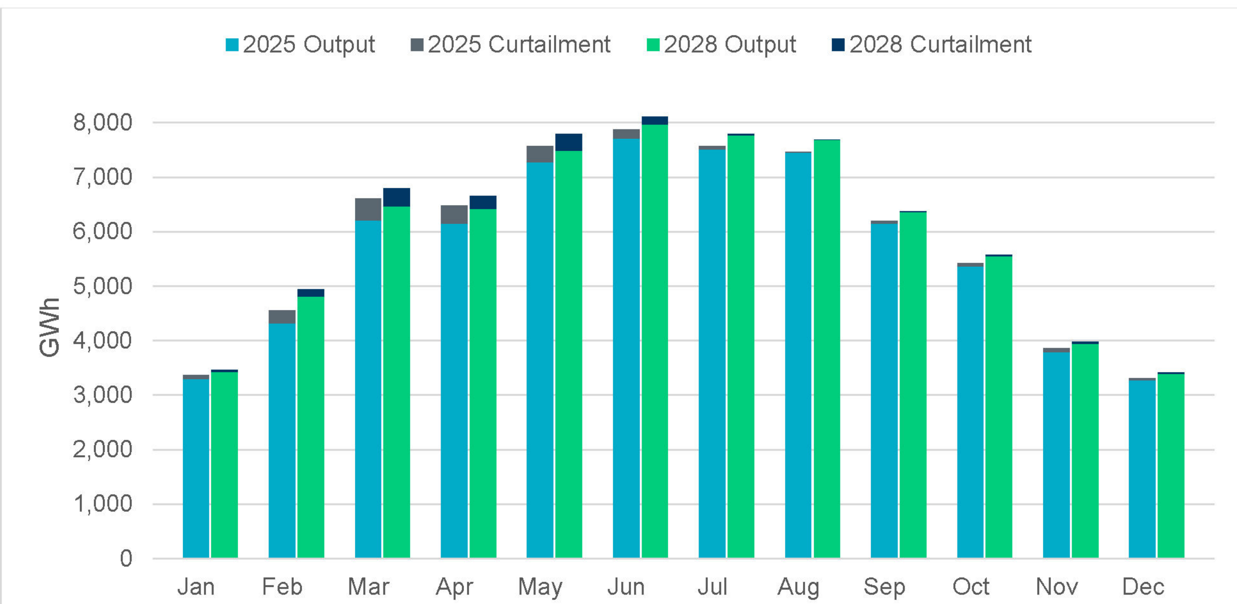

Figure 16: Solar Production and Curtailment

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

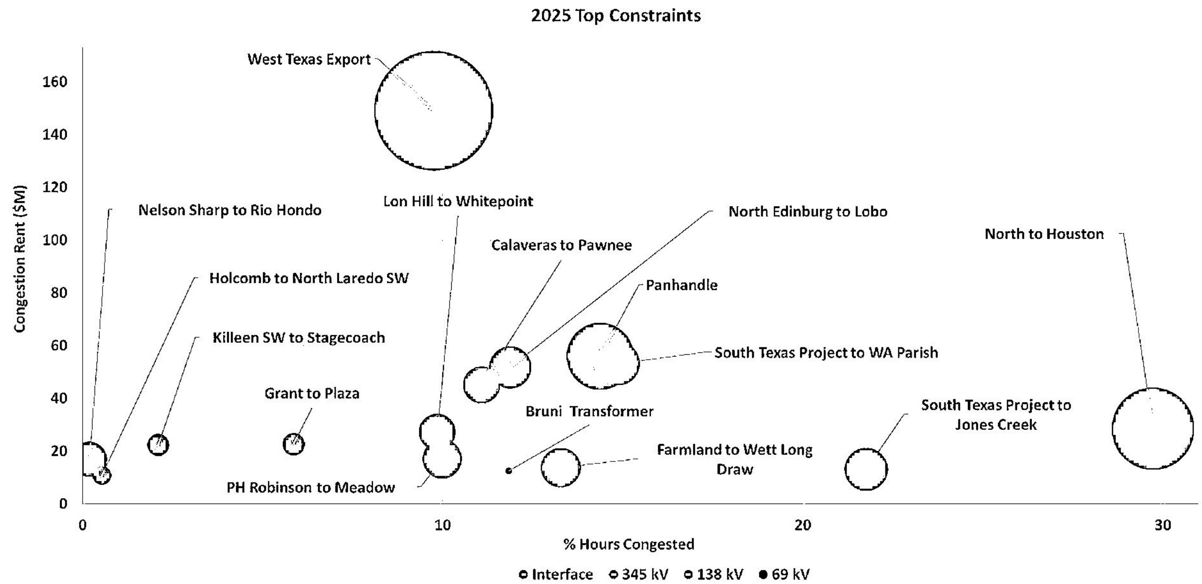

Figure 17: Top Constraints in 2025

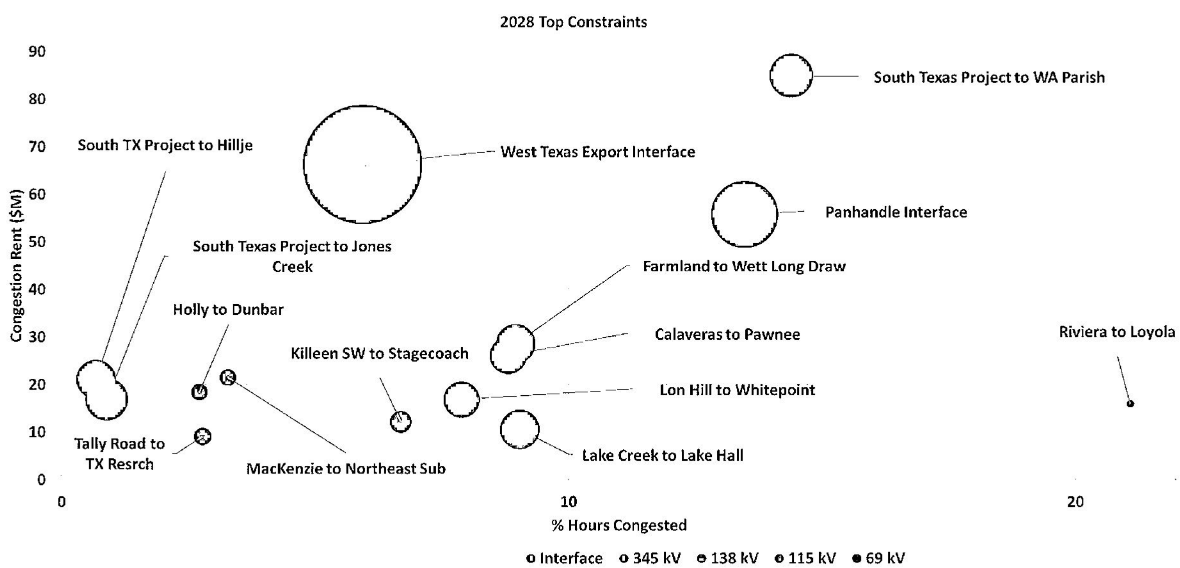

Figure18: Top Constraints in 2028[21]

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

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[21] Trumbull Transformer with 43% of congested hours and $7.3M congestion rent is not illustrated in the graph.
[22] https://www.ercot.com/files/docs/2023/08/28/ERCOT-EV-Adoption-Final-Report.pdf

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

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

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

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

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

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

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

4.1. Study Assumptions and Methodology

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

4.2. Top Constraints for 2025 and 2028 Study Years

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

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

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

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

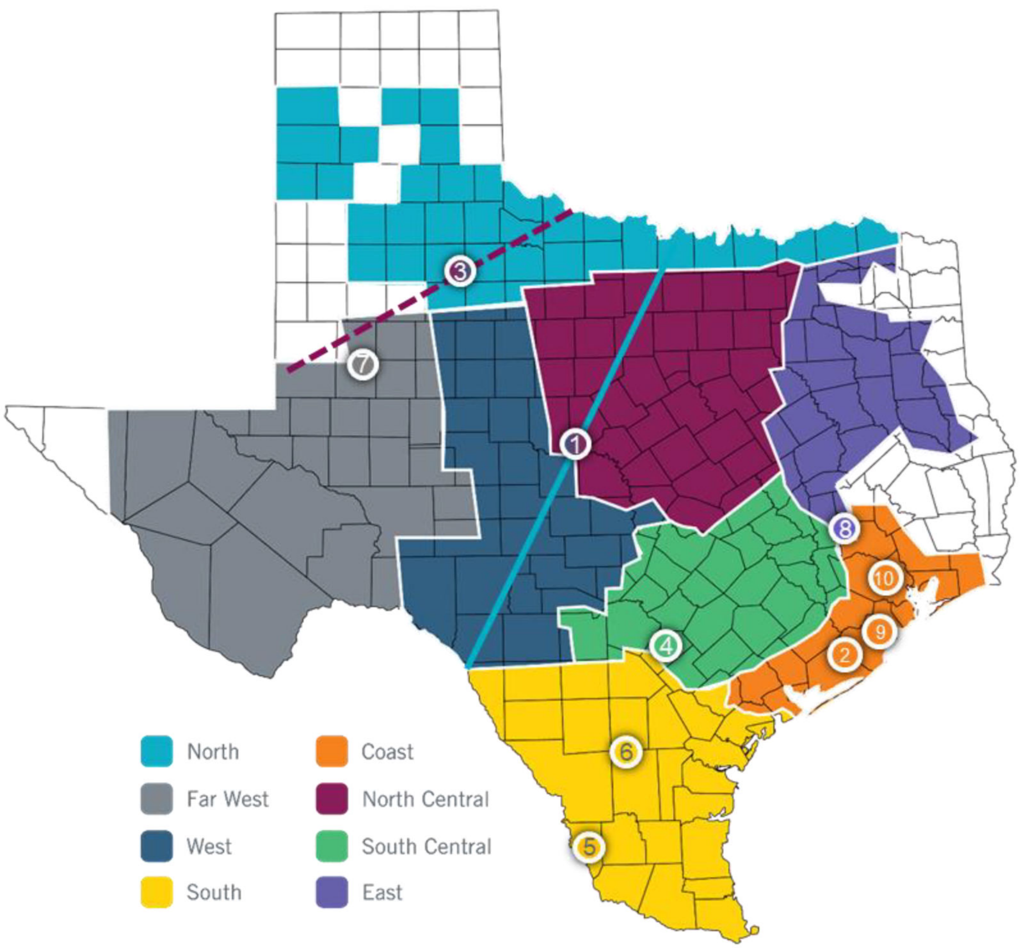

Figure 19: Locations of Top 10 Constraints in 2025 and 2028

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

4.3. Projects Selected for Evaluation

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

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

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

Table 7: Projects Selected for Economic Evaluation

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

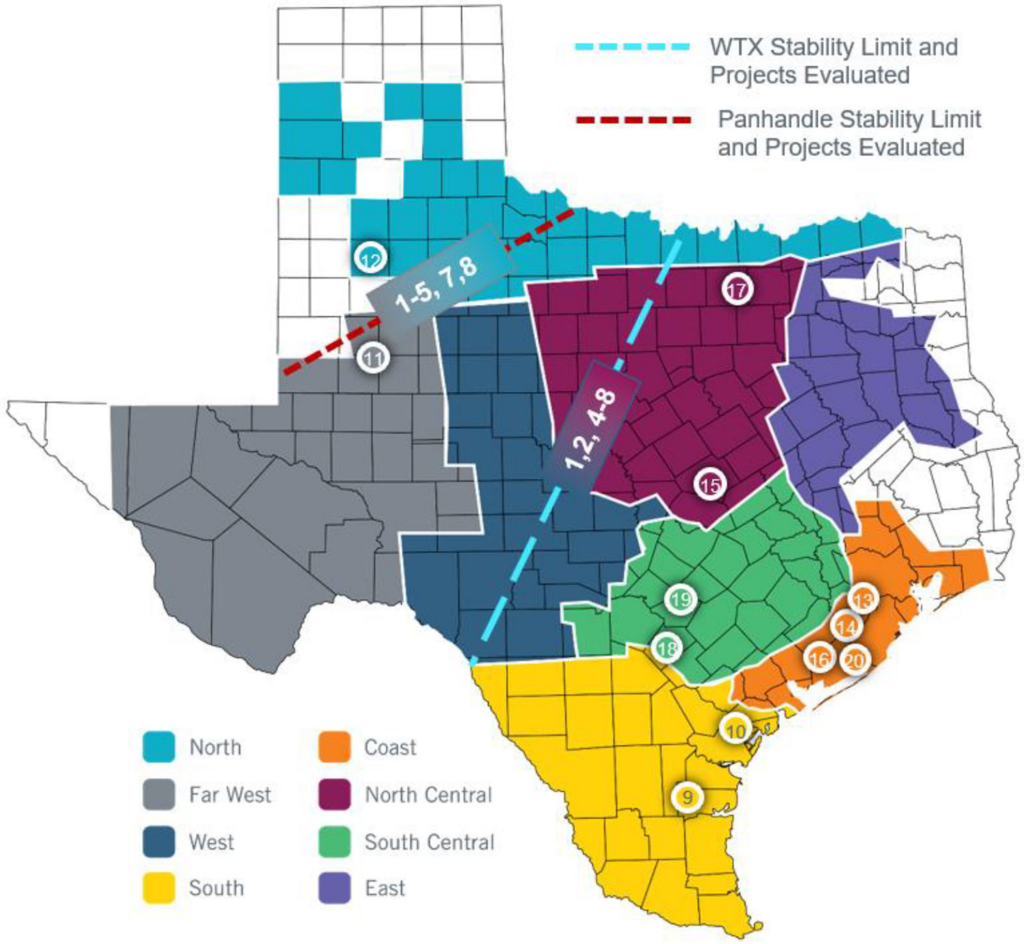

Figure 20: Proposed Project Locations

4.4. Project Evaluation Results

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

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

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

5. Appendices

Index	Description	Document	Access
A	RTP Scope and Process Document	Appendix_A_2023_RTP_Scope_and_Process_Final.pdf	Public
B	Input assumptions for the 2023 RTP reliability analysis	Appendix_B_2023_RTP_Reliability_Input_Assumptions.xlsx	Public
C	WFW IHS new load interconnection	Appendix_C_2023_RTP_WFW_IHS_New_Load_Interconnection.xlsx	MIS Secure
D	Input assumptions for the 2023 RTP economic analysis	Appendix_D_2023_RTP_Economic_Input_Assumptions.xlsx	Public
E	Economic analysis start case inputs and annual constraints	Appendix_E_2023_RTP_Economics_Start_Case_Inputs_Annual_Contraints.zip	MIS Secure
F	Reliability Driven Projects	Appendix_F_2023_RTP_Reliability_Projects.xlsx	MIS Secure
G	Project locations	Appendix_G_2023_RTP_Project_Locations.pdf	Public
H	Constraint Management Plans	Appendix_H_2023_RTP_Constraint_Management_Plans.xlsx	MIS Secure
I	Multiple element contingency analysis	Appendix_I_2023_RTP_MultipleElementContingencyStudyReport.docx	N/A
J	Facilities loaded over 95%	Appendix_J_2023_RTP_95%_Exceedance_PG31123.xlsx	MIS Secure
K	Sensitivity Analysis Results	Appendix_K_2023_RTP_Sensitivity_Projects.xlsx	MIS Secure
L	Short circuit Analysis	Appendix_L_2023_RTP_ShortCircuitStudyCases_DetailedResults.docx	MIS Secure
M	Long lead time equipment analysis	Appendix_M_2023_RTP_LongLeadTimeEquipment.docx	N/A
N	Transmission elements proposed to be dynamically rated	Appendix_N_2023_RTP_Dynamic_Rating_NP3_10_8_4.xlsx	MIS Secure
O	Minimum Deliverability Analysis	Appendix_O_2023_RTP_Minimum_Deliverability_Projects.xlsx	MIS Secure
P	Economic Analysis Results	Appendix_P_2023_RTP_Economic_Analysis.pdf	Public

DELAWARE BASIN STAGE 5

ERCOT RPG Submittal
May 2, 2024

Business and Operations Services
Assets Planning

ONCOR®

ATTACHMENT NO. 6

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Executive Summary

Oncor Electric Delivery Company LLC (Oncor) proposes the following Delaware Basin Stage 5 project (Proposed RPG Project). The transmission upgrades in this submittal mirror the improvements identified in the road map for transmission improvements in the ERCOT Delaware Basin Load Integration Study[1]. Additionally, this RPG project submittal mirrors the recommended solution presented in ERCOT's 2023 Regional Transmission Plan (RTP). This Tier 1 Proposed RPG Project will:

- Expand Oncor's existing Lamesa Switch, including a 13-breaker 138 kV breaker-and-a-half bus arrangement and a 9-breaker 345 kV breaker-and-a-half bus arrangement with two 600 MVA, 345/138 kV autotransformers. All terminal and associated equipment will meet or exceed 5000 A for 345 kV and 3200 A for 138 kV;
- Relocate the existing Lamesa 69 kV station equipment and establish the new Pivot 138/69 kV Switch at the current Welch Tap location. To establish the new Pivot 138/69 kV Switch, Oncor will:
  - Rebuild the existing 2-mile Lamesa – Welch Tap 69 kV Line using a conductor rated 2569 A or greater (normal and emergency rating of 614 MVA) and convert the line to 138 kV operation, and
  - Relocate one of the existing Lamesa 138/69 kV Autotransformers and three of the existing Lamesa 69 kV breakers to the new Pivot 138/69 kV Switch;
- Rebuild the Clearfork 345 kV Switch by installing thirteen 345 kV, 5000 A circuit breakers in a breaker-and-a-half bus arrangement;
- Install two 5000 A, 345 kV circuit breakers in a breaker-and-a-half bus arrangement at Oncor's Drill Hole 345/138 kV Switch;
- Construct a new approximately 105-mile 345 kV line from Oncor's Clearfork 345 kV Switch to Oncor's Drill Hole 345/138 kV Switch, on double-circuit capable structures with both circuits in place using a conductor rated 5000 A or greater (normal and emergency rating of 2988 MVA). This line will be routed near the location of Oncor's planned Border Switch for a future 345 kV interconnection to provide an injection point to support this high load growth area;
  - In ERCOT's Delaware Basin Load Integration Study – Stage 5, ERCOT recommended a new double-circuit line from Oncor's existing Clearfork 345 kV Switch to Oncor's existing Riverton 345/138 kV Switch. Oncor is recommending the line from Clearfork 345 kV Switch instead terminate at Oncor's Drill Hole 345/138 kV Switch (Drill Hole 345 kV Switch was proposed in Oncor's Delaware Basin Stages 3 and 4 RPG Submittal, currently under ERCOT Independent Review);
- Construct a new approximately 77-mile 345 kV line from Clearfork 345 kV Switch to the existing Lamesa Switch, on double-circuit capable structures with both circuits in place using a conductor rated 5000 A or greater (normal and emergency rating of 2988 MVA); and
- Construct a new approximately 38-mile 345 kV line from Oncor's existing Lamesa Switch to WETT's Faraday 345 kV Switch, on double-circuit capable structures with both circuits in place using a conductor rated 5000 A or greater (normal and emergency rating of 2988 MVA). Oncor will build half the line beginning from Oncor's Lamesa Switch (19 miles) and WETT will build the remaining half of the line beginning from Faraday Switch (19 miles).

[1] https://www.ercot.com/files/docs/2019/12/23/ERCOT_Delaware_Basin_Load_Integration_Study_Public_Version.zip

The Delaware Basin area of West Texas continues to experience significant load growth due to the high level of activities in the oil and gas industry. The Delaware Basin area spans the following eight counties: Brewster, Culberson, Jeff Davis, Loving, Pecos, Reeves, Ward, and Winkler.

The ERCOT Delaware Basin Load Integration Study identified the addition of a new Faraday - Lamesa - Clearfork - Riverton Double-Circuit 345-kV Line (Stage 5) as the necessary Stage 5 upgrade that would be triggered when load in the Delaware Basin Study Area exceeds 5,422 MW. In 2020, IHS Markit conducted a bottom-up analysis of electric load based on oil and gas industry intelligence, equipment requirements, and market dynamics. This analysis is summarized in the "West Texas Forecasted Load Additions: Permian Basin" report filed by ERCOT to the Public Utility Commission of Texas (PUCT) in April 2020.[2] In a subsequent letter, ERCOT concurred that the IHS Markit load forecast is reasonable and should be considered in the Permian Basin expansion strategy going forward.[3] Furthermore, the ERCOT 2023 Regional Transmission Plan (RTP) and the ERCOT 2021 Permian Basin Load interconnection study concluded that the Delaware Basin Area Stage 5 upgrades will be needed by summer of 2026.

In addition, steady-state assessments of the existing transmission facilities in this area of West Texas indicate that by the summer of 2026, low voltages are seen at several load-serving substations along the same corridor under post-contingency conditions. In addition, thermal overloading of an existing 345 kV transmission line was also observed.

This RPG project will upgrade the 345 kV transmission system in the Delaware Basin area consistent with Stage 5 of the Delaware Basin Load Integration Study, resolve all identified voltage violations in the area, improve system operational flexibility, increase system load serving capacity, and create an additional 345/138 kV source into the Delaware Basin area. This RPG submittal recommends modifying a portion of ERCOT's previously-identified Stage 5 upgrade project to terminate the new 345 kV double-circuit line from Clearfork Switch at Drill Hole Switch instead of Riverton Switch, as shown below in Figure 2. This modified version of ERCOT's Stage 5 upgrade is necessary because:

- The original ERCOT Delaware Basin Stage 3 recommended constructing a new 345 kV Riverton Switch – Owl Hills Double-Circuit Line; however, Owl Hills is solely a load-serving substation, while Drill Hole is an existing 138 kV Switch with the ability to expand to 345 kV capacity. This makes Drill Hole Switch a more suitable location for the new 345 kV Switch and associated line termination, as discussed in Oncor's Delaware Basin Stage 3 RPG Submittal.
- Whether constructed at Owl Hills or Drill Hole Switch, the new 345 kV Switch recommended in ERCOT's Delaware Basin Load Integration Study would have been constructed at the end of a radial 345 kV double-circuit line from Riverton Switch. Terminating the new 345 kV double-circuit line from Clearfork Switch into this expanded Drill Hole station with a new 345 kV switchyard will network that facility, and its associated 345/138 kV autotransformer capacity, into the rest of the 345 kV transmission system.
- Furthermore, terminating the new 345 kV double-circuit line from Clearfork into the Drill Hole 345 kV Switch will provide another 345 kV injection point into an area of the transmission system that is experiencing accelerated load growth, thus creating a more robust and flexible transmission grid.

[2] https://interchange.puc.texas.gov/Documents/27706_439_1147915.pdf
[3] https://interchange.puc.texas.gov/Documents/27706_468_1096555.pdf

- Finally, after completion of the proposed Delaware Basin Stage 3 project under ERCOT Independent Review, (Riverton Switch – Drill Hole Switch 345 kV Double-Circuit Line), all of the Riverton 345 kV Switch terminals will be in use, so there will be no locations at the Riverton 345 kV Switch to terminate a new 345 kV double-circuit line from Clearfork Switch. The Riverton 345 kV Switch property does not allow for further expansion of the 345 kV Switch. Therefore, Oncor proposes modifying the portion of ERCOT's Stage 5 upgrade project to terminate the 345 kV double-circuit line from Clearfork Switch at Drill Hole Switch instead of Riverton Switch.

This estimate $744.60 million Tier 1 project in the Delaware Basin is recommended for construction to meet a December 2029 in-service date. The projected in-service date may change based on requirements for environmental assessment and construction progress. This Proposed RPG Project has components which will require a CCN. The cost estimate accounts for the expectation that some construction activities will occur in an energized transmission line corridor. If necessary, Oncor will work with ERCOT to develop and implement Constraint Management Plans (CMPs) such as line sectionalizing or mobile equipment/capacitor installation based on summer 2029 and 2030 operational conditions.

Introduction

This submittal describes the need to expand the existing Lamesa Switch and establish the new Pivot 138/69 kV Switch; rebuild the existing 2-mile Lamesa - Welch Tap 69 kV Line to operate at 138 kV; rebuild the Clearfork 345 kV Switch; install two 345 kV circuit breakers at Oncor's Drill Hole 345/138 kV Switch; and construct a new Faraday – Lamesa – Clearfork – Drill Hole 345 kV Double-Circuit Line in Andrews, Borden, Culberson, Dawson, Gaines, Loving, Reeves, and Winkler counties. Oncor continues to see load growth in this area of west Texas due to the high level of activities in the oil and gas industry. The strong need in this area is mainly driven by new loads and electrification activities, including conversion of gas-powered equipment to electrical operation and moving load from on-site generation to the transmission grid. The Proposed RPG Project is needed to relieve low voltage and thermal overload conditions, to meet NERC, ERCOT and Oncor's reliability standards/criteria. Figures 1 and 2 below show an area map and the transmission system improvements for the Proposed RPG Project.

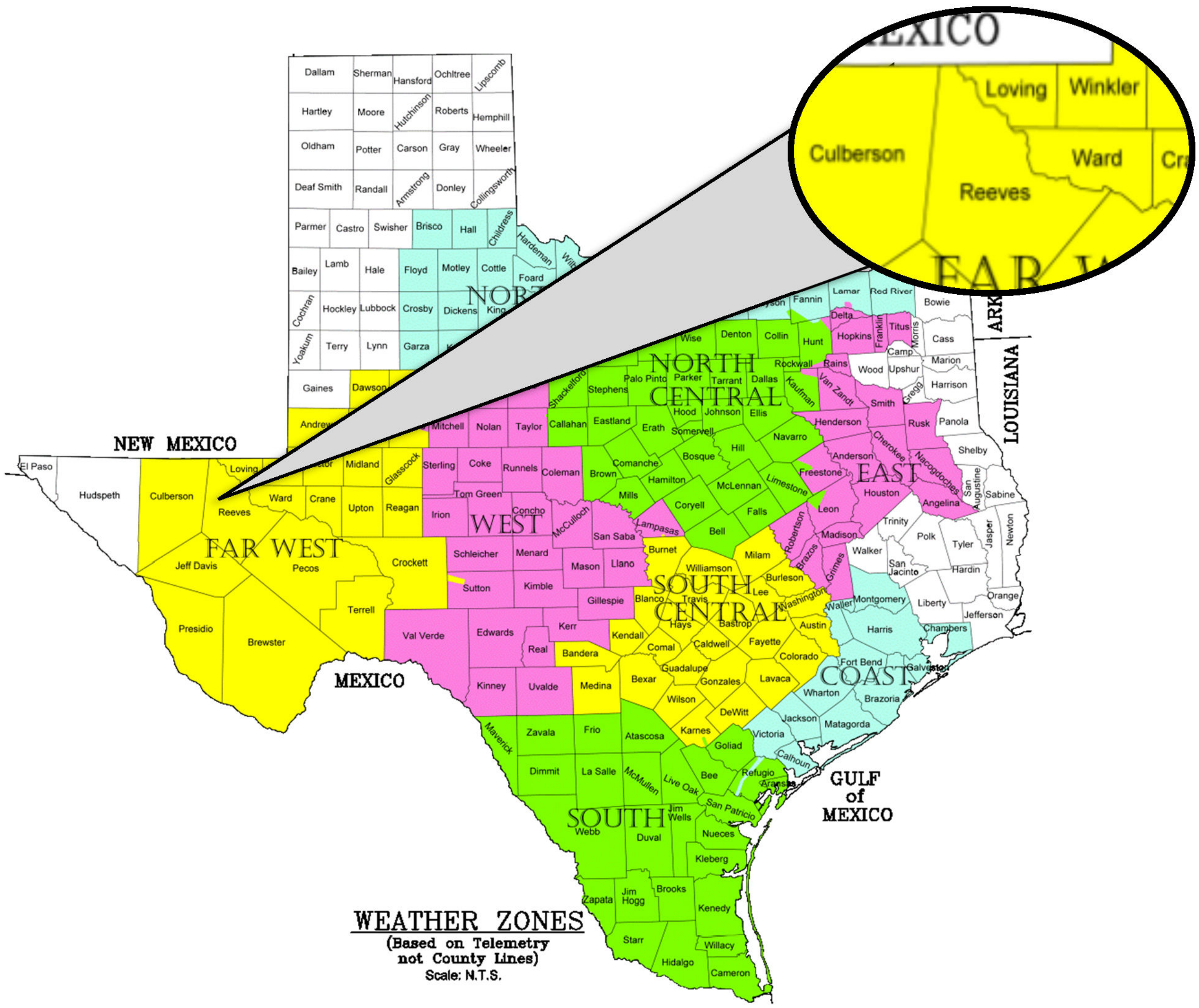

Figure 1. Delaware Basin Stage 5 Area Map

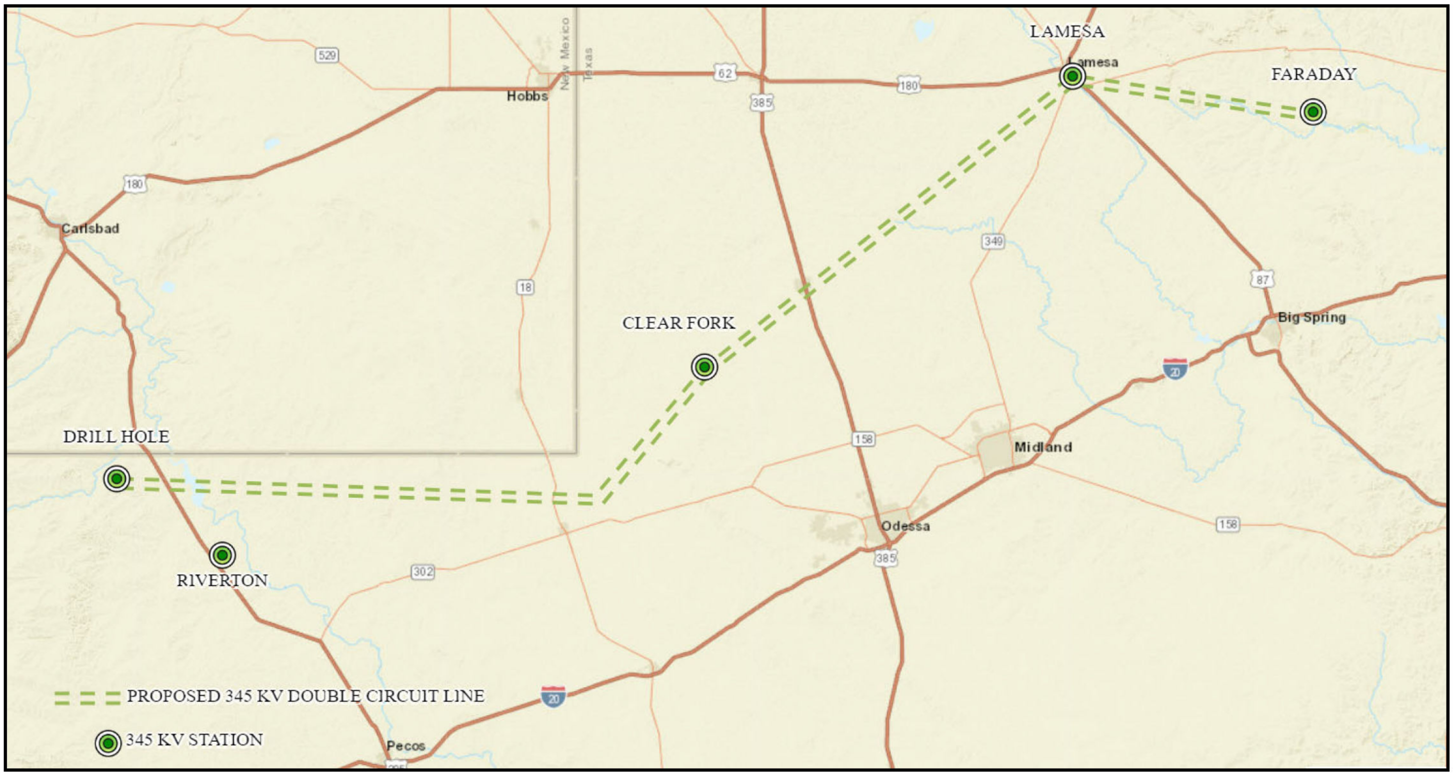

Figure 2. Delaware Basin Stage 5 Proposed Transmission System Improvements

Figure 3 below shows the triggers for the transmission upgrades at each stage of the Delaware Basin Load Integration Study in terms of the load level in the Delaware Basin area. Table 1 lists the details of the transmission upgrades associated with each stage in the developed roadmap of the Delaware Basin Load Integration Study. The triggers and limits are based on either thermal or steady state voltage stability criteria violations under the N-1, G-1+N-1, X-1+N-1, and N-1-1 contingency conditions.

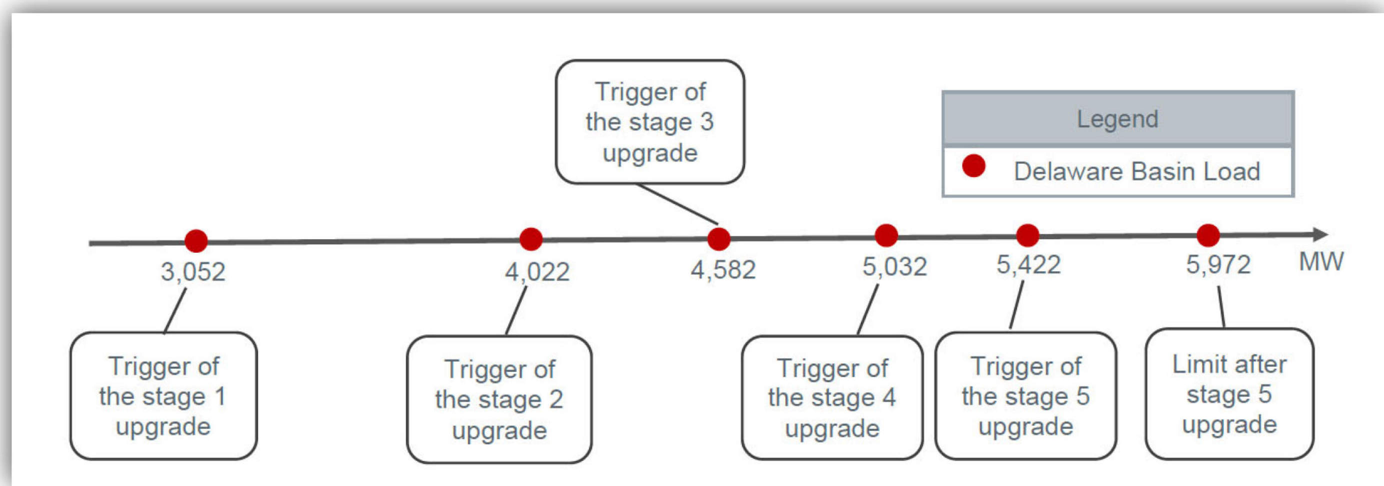

Figure 3. Delaware Basin Transmission Upgrade Roadmap

Stage	Estimated Delaware Basin Load Level (MW)	Upgrade Element	Estimated Upgrade Cost ($M)	Trigger
1	3,052	Add a second circuit on the existing Big Hill - Bakersfield 345-kV line	69	Import Needs
2	4,022	A new Bearkat - North McCamey - Sand Lake double circuit 345-kV line	371	Import Needs
3	4,582	A new Riverton - Owl Hills single circuit 345-kV line	41	Culberson Loop Needs
4	5,032	Riverton - Sand Lake 138-kV to 345-kV conversion and a new Riverton - Sand Lake 138-kV line	56	Culberson Loop Needs
5	5,422	A new Faraday - Lamesa - Clearfork - Riverton double circuit 345-kV line	444	Import Needs

Table 1. Delaware Basin Transmission Upgrade Roadmap – Detailed Project List

Purpose and Necessity

The existing transmission infrastructure in the Delaware Basin area of West Texas needs a new 345 kV import path to provide improved load serving capability. Adding a new 345 kV pathway in this area will reinforce the existing transmission system and improve power quality. The Delaware Basin Stage 5 transmission upgrades aligns with the improvements identified in the road map for transmission improvements in the Delaware Basin Load Integration Study. To that extent, this RPG project submittal builds on the planning analysis presented in ERCOT RTP report.

Steady-State Analysis

In the ERCOT Delaware Basin Load Integration Study, the Delaware Basin load trigger for the Stage 5 upgrade is 5422 MW. Table 2 shows the Delaware Basin load totals for the SSWG cases published on October 9, 2023. As shown in Table 2, the 5422 MW Stage 5 load level is exceeded by Summer 2025.

Delaware Basin Load Levels		
Year	**MW**	**MVAR**
2024 SUM	5188.3	1578.0
2025 SUM	**5513.6**	1651.1
2026 SUM	6191.8	1786.1
2027 SUM	6308.5	1816.5
2028 SUM	6399.1	1838.3
2029 SUM	6454.3	1848.8
2030 SUM	6568.9	1872.5
2026 MIN	5474.9	1582.8

Table 2. Delaware Basin Load in 2023 SSWG cases published on October 9, 2023

In addition, Oncor steady-state assessments of the existing transmission facilities in this area of West Texas indicate that by the summer of 2026, low voltages are seen at several load-serving substations along the same corridor under post-contingency conditions. Thermal overloading of existing 138 kV and 345 kV transmission lines was also observed. The cases used for this study were the ERCOT Steady State Working Group (SSWG) cases published October 9, 2023 (23SSWG_2026_SUM1_U1_Final_10092023.sav and 23SSWG_2027_SUM1_U1_Final_10092023.sav). All appropriate off-cycle idevs were applied to the cases.

- The base case was modified to include approximately 1,006 MW of newly signed Oncor loads

- Oncor's Rockhound 345/138 kV Switch and Grey Well Draw - Buffalo 2nd 138 kV Circuit Project (24RPG002 - approved by RPG on 2/6/24), and Prairieland 345/138 kV Switch and Prairieland Switch - Quartz Sand Switch/Hog Mountain POD 138 kV Line Project (24RPG006 approved by RPG on 3/18/24) were also included in the analysis.

The post-contingency conditions that result in low voltage and thermal violations include multiple contingency scenarios per NERC Standard TPL-001-5, ERCOT Planning Guide Reliability Performance Criteria 4.1.1.2.1(d), and Oncor criteria. The results justifying the need for the Proposed RPG Project and subsequent results after the Proposed RPG Project is completed are summarized in Tables 3 and 4 below.

Voltage Violations

Post-contingency Voltage Performance							
NERC Category	Contingency	Monitored Bus Number	Monitored Bus Name	Voltage (p.u.)			
				2026 Summer		2027 Summer	
				Pre-Project	Post-Project	Pre-Project	Post-Project
P1[1] / P7[2]	P1: Rockhound – Prongmoss 345 kV Line (PSSE Buses 10062 – 10057 ckt id 1)	10036	LAZYRNCH_8	0.922	0.961	0.936	0.969
		23840	GLSRNCH_8	0.922	0.961	0.936	0.969
	P7: Rockhound – Prongmoss 345 kV Double-Circuit Line (PSSE Buses 10062 – 10057 ckt id 1 & 2)	11371	REDSAND_P8	0.921	0.960	0.934	0.967
		23841	SALRNCH_8	0.922	0.961	0.932	0.966
P7	Redacted	Redacted	Redacted	Unsolved Power Flow[3]	0.956	0.947	0.973
		Redacted	Redacted		0.957	0.948	0.973
		Redacted	Redacted		0.958	0.949	0.975
P7	Wolf – Quarry Field 345 kV Double-Circuit Line (PSSE Buses 11010 – 11188 ckt id 1 & 2)	1077	BALDING_8	0.9497	0.9826	0.942	0.978
		11382	ASHBY_P8	0.9530	0.9859	0.946	0.981
		18680	BLUEMTN_8	0.9533	0.9861	0.946	0.981
		11070	WILLOWLS_8	0.9531	0.9859	0.946	0.981

1. P1 contingency applies to 2026 Summer
2. P7 contingency applies to 2027 Summer
3. Unsolved Power Flow due to extraordinary area low voltages

Table 3 - Post-Contingency Voltage Performance

Thermal Violations

Post-contingency Thermal Loading						
NERC Category	Contingency	Monitored Element	Percent Loading			
			2026 Summer		2027 Summer	
			Pre-Project	Post-Project	Pre-Project	Post-Project
P7	LCRA Bakersfield – AEP Solstice 345 kV Double-Circuit Line (PSSE Buses 76002 – 60404 ckt id 1 & 2)	LCRA Bakersfield – GPL Nevil Road 345 kV Line	111.9	98.7	108.7	99.9
P3	Contingency 1: MACHINE 132881 ID S1 Contingency 2: Vealmoor – Long Draw 345 kV Line	Lamesa – Willow Valley 138 kV Line	122.2	46.1	109.7	42.2
P6	Contingency 1: Vealmoor Autotransformer #1 Contingency 2: Long Draw – Volta 345 kV Line	Vealmoor Autotransformer #2	103.7	77.2	94.4	74.0

Table 4 - Post-Contingency Thermal Loading

Dynamic Analysis

Oncor performed a dynamic analysis to evaluate the impact of the addition of this project on the transmission system. The analysis was conducted using the latest Dynamic Working Group (DWG) 2025 summer peak case and 2026 HWLL case published May 2023 (2025_SP_Final_NonCnv35.sav and 2026_HWLL_Final_NonCnv35.sav). System topology updates necessary to implement the Proposed RPG Project were used in the study case. The results of the stability assessment, with the addition of the Proposed RPG Project, demonstrate that there was no adverse effect on the transmission system with the Proposed RPG Project in-service. Oncor will continue to perform annual dynamic analysis for this area.

Short-Circuit Study

Oncor evaluated the short-circuit impacts of the proposed project using the System Protection Working Group (SPWG) case (23_SPWG_2025_FY_11062023_FINAL) and did not identify any overdutied breakers. The SPWG case was modified to include changes associated with the Proposed RPG Project, as well as other Oncor system changes that occurred since the development of the SPWG case. Oncor will continue to perform annual short-circuit studies to assess the impact of future projects.

Subsynchronous Resonance (SSR) Screening

Oncor performed an SSR screening assessment with all series capacitors and generator units in service to identify new potential SSR vulnerabilities within the ERCOT system as a result of the Proposed RPG Project. The study was performed with and without the Proposed RPG Project and confirmed the Proposed RPG Project did not create any new or shorter paths leading to generation sources becoming radial with series capacitors in the event of fewer than 14 concurrent transmission outages. No further SSR analysis is required for the Proposed RPG Project.

Project Description

In order to address the identified reliability concerns, Oncor recommends the following Proposed RPG Project:

- Expand Oncor's existing Lamesa Switch, including a 13-breaker 138 kV breaker-and-a-half bus arrangement and a 9-breaker 345 kV breaker-and-a-half bus arrangement with two 600 MVA, 345/138 kV autotransformers. All terminal and associated equipment will meet or exceed 5000 A for 345 kV and 3200 A for 138 kV;
- Relocate the existing Lamesa 69 kV station equipment and establish the new Pivot 138/69 kV Switch at the current Welch Tap location. To establish the new Pivot 138/69 kV Switch, Oncor will:
    - Rebuild the existing 2-mile Lamesa – Welch Tap 69 kV Line using a conductor rated 2569 A or greater (normal and emergency rating of 614 MVA) and convert the line to 138 kV operation, and
    - Relocate one of the existing Lamesa 138/69 kV Autotransformers and three of the existing Lamesa 69 kV breakers to the new Pivot 138/69 kV Switch;
- Rebuild the Clearfork 345 kV Switch by installing thirteen 345 kV, 5000 A circuit breakers in a breaker-and-a-half bus arrangement;
- Install two 5000 A, 345 kV circuit breakers in a breaker-and-a-half bus arrangement at Oncor's Drill Hole 345/138 kV Switch;
- Construct a new approximately 105-mile 345 kV line from Oncor's Clearfork 345 kV Switch to Oncor's Drill Hole 345/138 kV Switch, on double-circuit capable structures with both circuits in place using a conductor rated 5000 A or greater (normal and emergency rating of 2988 MVA). This line will be routed near the location of Oncor's planned Border Switch for a future 345 kV interconnection to provide an injection point to support this high load growth area;
- Construct a new approximately 77-mile 345 kV line from Clearfork 345 kV Switch to the existing Lamesa Switch, on double-circuit capable structures with both circuits in place using a conductor rated 5000 A or greater (normal and emergency rating of 2988 MVA); and
- Construct a new approximately 38-mile 345 kV line from Oncor's existing Lamesa Switch to WETT's Faraday 345 kV Switch, on double-circuit capable structures with both circuits in place using a conductor rated 5000 A or greater (normal and emergency rating of 2988 MVA). Oncor will build half the line beginning from Oncor's Lamesa Switch (19 miles) and WETT will build the remaining half of the line beginning from Faraday Switch (19 miles).

One-Line Diagram

Figure 4 shows a one-line diagram with dashed elements depicting the Proposed RPG project.

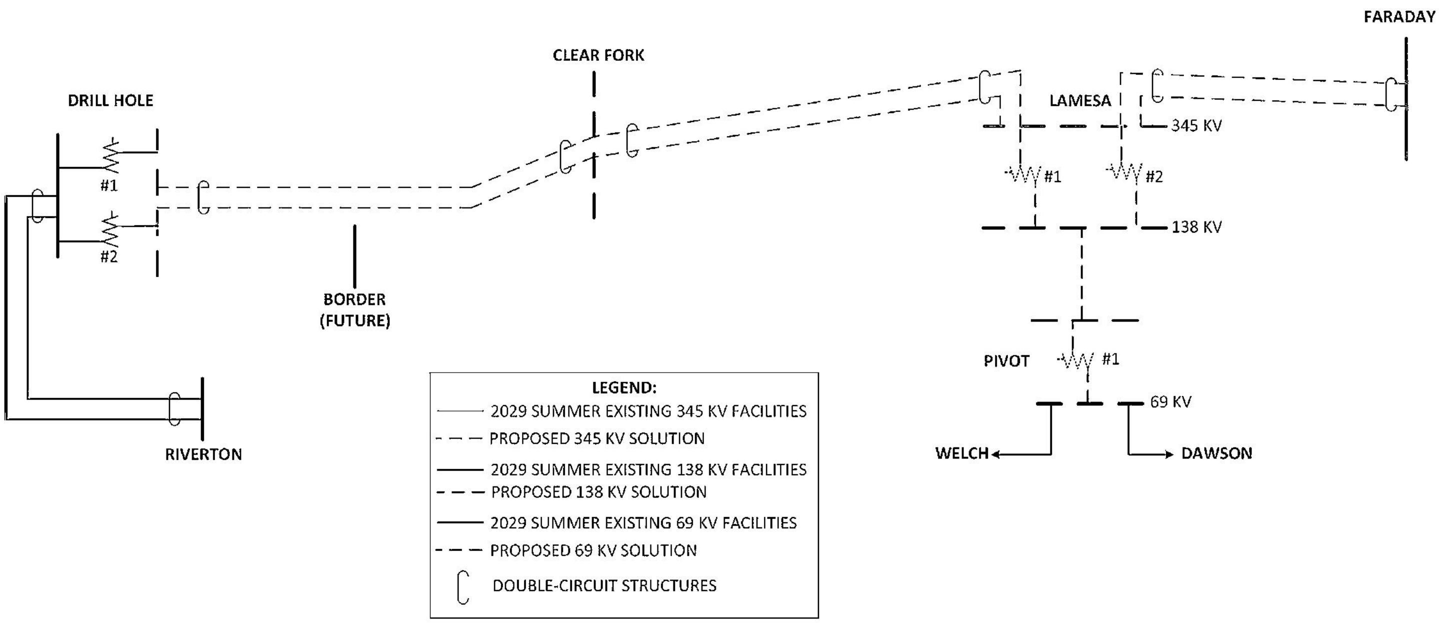

Figure 4. Proposed RPG Project One-Line Diagram

Alternative Solution

This project is proposing to implement a portion of the roadmap for transmission improvements in the ERCOT Delaware Basin Load Integration Study, which evaluated more than 10 alternatives informed by TSP input and shortlisted a set of four options leading to the staged roadmap of improvements.

Given the Delaware Basin Load Integration Study's robust alternative analysis, no further alternative analysis is necessary. However, should ERCOT disagree and study alternatives, Oncor would recommend consideration of the following:

- Lamesa Switch to Scurry County South Switch 345 kV Line
- Lamesa Switch to Dermott Switch 345 kV Line
- Clearfork Switch to McKenzie Draw Switch to Vealmoor Switch to Scurry County South Switch 345 kV Line

Recommendation

Oncor recommends the following Proposed RPG Project as the best solution to resolve the post-contingency thermal violations identified in the analysis of the study area.

- Expand Oncor's existing Lamesa Switch, including a 13-breaker 138 kV breaker-and-a-half bus arrangement and a 9-breaker 345 kV breaker-and-a-half bus arrangement with two 600 MVA, 345/138 kV autotransformers. All terminal and associated equipment will meet or exceed 5000 A for 345 kV and 3200 A for 138 kV;
- Relocate the existing Lamesa 69 kV station equipment and establish the new Pivot 138/69 kV Switch at the current Welch Tap location. To establish the new Pivot 138/69 kV Switch, Oncor will:
  - Rebuild the existing 2-mile Lamesa – Welch Tap 69 kV Line using a conductor rated 2569 A or greater (normal and emergency rating of 614 MVA) and convert the line to 138 kV operation, and
  - Relocate one of the existing Lamesa 138/69 kV Autotransformers and three of the existing Lamesa 69 kV breakers to the new Pivot 138/69 kV Switch;
- Rebuild the Clearfork 345 kV Switch by installing thirteen 345 kV, 5000 A circuit breakers in a breaker-and-a-half bus arrangement;
- Install two 5000 A, 345 kV circuit breakers in a breaker-and-a-half bus arrangement at Oncor's Drill Hole 345/138 kV Switch;
- Construct a new approximately 105-mile 345 kV line from Oncor's Clearfork 345 kV Switch to Oncor's Drill Hole 345/138 kV Switch, on double-circuit capable structures with both circuits in place using a conductor rated 5000 A or greater (normal and emergency rating of 2988 MVA). This line will be routed near the location of Oncor's planned Border Switch for a future 345 kV interconnection to provide an injection point to support this high load growth area;
- Construct a new approximately 77-mile 345 kV line from Clearfork 345 kV Switch to the existing Lamesa Switch, on double-circuit capable structures with both circuits in place using a conductor rated 5000 A or greater (normal and emergency rating of 2988 MVA); and
- Construct a new approximately 38-mile 345 kV line from Oncor's existing Lamesa Switch to WETT's Faraday 345 kV Switch, on double-circuit capable structures with both circuits in place using a conductor rated 5000 A or greater (normal and emergency rating of 2988 MVA). Oncor will build half the line beginning from Oncor's Lamesa Switch (19 miles) and WETT will build the remaining half of the line beginning from Faraday Switch (19 miles).

Expanding Oncor's existing Lamesa Switch, establishing the new Pivot 138/69 kV Switch, rebuilding the existing 2-mile Lamesa – Welch Tap 69 kV Line to operate at 138 kV, rebuilding the Clearfork 345 kV Switch, installing two 345 kV circuit breakers at Oncor's Drill Hole 345/138 kV Switch, and constructing a new Faraday – Lamesa – Clearfork– Drill Hole 345 kV Double-Circuit Line will meet reliability requirements, relieve the thermal overloading, maintain acceptable system voltages, add a new 345 kV injection point to existing facilities, improve overall system strength and import capability, and provide adequate transmission capacity for the system under pre- and post-contingency conditions. Oncor will work with ERCOT to develop and implement CMPs based on summer 2029 and 2030 operational conditions as necessary. The estimated cost for this Tier 1 Proposed RPG Project is $744.60 million, based on the expectation that some elements of this project will be constructed using energized (hot) work processes.

ERCOT Independent Review of the Combined Delaware Basin Stage 5 Project and Alternative

ATTTACHMENT NO. 7

Document Revisions

Date	Version	Description	Author(s)
5/16/2025	1.0	Final	Tanzila Ahmed
		Reviewed by	Robert Golen, Prabhu Gnanam

Executive Summary

Oncor Electric Delivery Company LLC (Oncor) submitted the Delaware Basin Stage 5 Project to the Regional Planning Group (RPG) in May 2024. Oncor proposed this project to address NERC TPL-001-5.1, ERCOT Planning Guide, and Oncor reliability criteria violations (both voltage violations and thermal overloads) in the Delaware Basin area in Andrews, Borden, Culberson, Dawson, Gaines, Loving, Reeves, and Winkler Counties in the Far West (FW) Weather Zone.

The Oncor proposed project was estimated to cost approximately $744.6 million, was classified as a Tier 1 project per ERCOT Protocol Section 3.11.4.3, and the project will require a Certificate of Convenience and Necessity (CCN) application.

Wind Energy Transmission Texas, LLC (WETT) submitted the Delaware Basin Stage 5 Project Alternative to RPG in June 2024. WETT estimates the total cost of WETT's portion of the alternative project to be approximately $305.5 million, was classified as a Tier 1 project per ERCOT Protocol Section 3.11.4.3, and will require CCN application.

ERCOT completed the Delaware Basin Load Integration Study[1] (DBLIS) in December 2019, following review and input by the affected Transmission and Distribution Service Providers (TDSPs). This study, which identified the reliability needs of the region, provides a long lead time transmission improvement roadmap for the continued oil and gas load growth in the Delaware Basin area. The RPG project, as submitted by Oncor, aligns with the Stage 5 upgrades identified in the DBLIS. The study found that the addition of a new Riverton to Clearfork to Lamesa to Faraday 345-kV double-circuit transmission lines (Stage 5 upgrade) as the recommended option for an import path option to further reliably serve load once the peak demand level of the Delaware Basin area exceeds 5,422 MW. Due to physical limitations of the Owl Hills substation, Oncor recommended, and the ERCOT Board of Directors (BOD) endorsed on December 3, 2024, a slight modification to the original Stage 3 upgrade by locating the new 345-kV substation at Drill Hole instead of Riverton, approximately one-quarter of a mile further from Riverton than the Owl Hills station.

In the 2024 ERCOT Permian Basin Reliability Plan Study[2], ERCOT identified the reliability needs in the Permian Basin region. In addition to the import paths, local transmission upgrades were also identified to serve the Permian Basin region loads. The updated Stage 3 and Stage 5 upgrades as well as the original Stage 4 upgrade from the 2019 DBLIS were included in the base case of this study.

ERCOT performed a single Independent Review to confirm the need for this project and evaluated both options to identify the best solution.

Accordingly, based on the ERCOT Independent Review (EIR), ERCOT recommends the following project as submitted by Oncor:

[1] 2019 ERCOT Delaware Basin Load Integration Study Report: https://www.ercot.com/gridinfo/planning
[2] 2024 ERCOT Permian Basin Reliability Plan Study Report: https://www.ercot.com/gridinfo/planning