ERCOT System Planning

2015 Regional Transmission Plan Report

Executive Summary

The 2015 Regional Transmission Plan (RTP) is the result of a coordinated planning process performed by ERCOT with extensive review and input by NERC-registered Transmission Planners (TPs), Transmission Owners (TOs) and other stakeholders. The RTP addresses ERCOT System reliability and economic transmission needs for years 2016 through 2021. This report documents the results of the assessment in part to comply with the requirements from NERC Reliability Standards, ERCOT Protocols and ERCOT Planning Guide.

The 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. For the planning horizons, the 2015 RTP assessed ERCOT's steady state transmission needs under summer peak and off-peak conditions. In addition to the seasonal variations, the RTP also included various sensitivities to address uncertainty involved in the transmission planning process. The reliability analysis in the 2015 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 planners in collaboration with Transmission Planners developed corrective action plans to address reliability concerns 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 majority of planned improvements identified in the 2015 RTP are 138-kV and 69-kV upgrades. Most of the projects identified as 345-kV upgrades consist of either the addition of a new 345/138-kV transformer or an upgrade of an existing 345/138-kV transformer.

The 2015 Regional Transmission Plan identified the following noteworthy reliability projects:

- New 345/138-kV transformer (third transformer) near the Zenith substation in Harris County

- One additional 345/138-kV transformer at the Palmito Substation in Cameron County in the Lower Rio Grande Valley (LRGV)
- Upgrade of existing 345/138-kV transformers at the San Miguel substation in Atascosa County
- A new 144 MVAr reactor at the Kiamichi 345-kV substation in Pittsburg County in Oklahoma
- A minimum of 50 MVAr reactor at the Clayton 345-kV substation in Fisher County
- A new second 345/138-kV transformer at the Vealmoor substation in Borden County
- Cross Valley Tap project which adds a 345/138-kV transformer at South McAllen in Hidalgo County.[1]
- One additional 345/138-kV transformer in the South McAllen area[2] in Hidalgo County
- Addition of second 345/138-kV transformer at the Twin Buttes substation in Tom Green County and the Hicks Switch substation in Tarrant County
- A new 345/138-kV transformer at the Cenizo substation in Webb County
- A new single-circuit 345-kV transmission line from new North Hill 345-kV substation (near Lon Hill, north of Nueces County) to new Zia 345-kV substation (on the existing Rio Hondo-North Edinburg 345-kV line) in LRGV.[3]

In addition to the reliability analysis, the 2015 RTP also includes an economic assessment of the ERCOT transmission system for years 2018 and 2021. Through this assessment, ERCOT planners identify transmission congestion and test various transmission upgrades to address the congestion in a cost-effective manner (as defined by ERCOT's economic planning criteria). Six projects were evaluated using the economic criteria, and one project, namely, the upgrade of the 138-kV line between Solstice and Pig Creek Substations in Pecos County showed enough savings to justify the project.

The project completion years stated in this 2015 RTP Report were chosen to address reliability and economic 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

[1] The Cross Valley Tap project was previously recommended in the 2013 RTP which adds a 345/138-kV transformer at the South McAllen substation.
[2] Project "Hidalgo-Starr Transmission Project" which addresses this need is currently under ERCOT's independent RPG project review.
[3] Project "LRGV Transmission Addition Project" which addresses this need is currently under ERCOT's independent RPG project review

availability of construction clearances, time required to receive regulatory or governmental approvals, equipment availability, land acquisition and resource constraints may result in different project completion dates. The scope of projects identified in the RTP may change if further analyses by ERCOT or the TPs find better alternatives or a need for modifying the projects due to changes in expected generation, load forecasts, or other system conditions. Projects requiring Regional Planning Group (RPG) approval will be reviewed in future assessments (where sufficient lead time exists), such as future Regional Transmission Plans, to ensure the identified system facilities are still needed.

The TOs designated to complete these projects will provide ERCOT additional details on project scope, project cost and an implementation schedule with completion date(s). 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. RTP Process

This report documents the 2015 Regional Transmission Plan (RTP) performed by ERCOT System Planning in accordance with the ERCOT Planning Guide Section 3. It is intended, in part, to satisfy ERCOT's requirements under NERC Reliability Standards, ERCOT Protocol Section 3.11 and ERCOT Planning Guide Sections 3 and 4.

The Regional Transmission Plan study is conducted annually for the entire ERCOT System. The 2015 RTP analyzed the reliability and efficiency of the ERCOT transmission system for the years 2016, 2018, 2020 and 2021. The 2015 RTP performed steady state analyses and short circuit analysis as required by NERC Standard TPL-001-4 for the years 2016, 2018 and 2020 for the near-term planning horizon. The 2015 RTP also included steady state analyses for 2021, representing the long-term planning horizon. The year six, or 2021, was selected based on the rationale that most of ERCOT transmission upgrades can be completed within five to six years from the date when the need is identified.

1.1 Standards and Regulations

The RTP assessment is conducted based on the NERC Standards, ERCOT Protocols, and ERCOT Planning Guide.

1.1.1 NERC Standard

The RTP performed its steady state reliability assessment in accordance with NERC reliability standard TPL-001-4 "Transmission System Planning Performance Requirements".

1.1.2 ERCOT Protocols

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 Dynamic Rating and request such Dynamic Ratings from the associated ERCOT TSP. This report identifies such Transmission Elements as part of its economic analysis. ERCOT Protocols Section 3.11.5 specifies the economic planning criteria used to evaluate efficiency of projects in the RTP.

1.1.3 ERCOT Planning Guide

The RTP assessment adheres to ERCOT Planning Guide Section 3.1.1.2 which specifies the guidelines to perform the RTP. This section also requires that ERCOT completes and publishes the final RTP report no later than December 31st of each year. Additionally, the ERCOT Planning Guide Section 4 and ERCOT Protocol Sections 3.11.2 specifies the transmission planning criteria to be used in the RTP assessment.

1.2 Stakeholder Involvement

The RTP is a collaborative process. ERCOT worked with NERC-registered Transmission Planners (TP)s, Transmission Owners (TO)s and other stakeholders to develop input assumptions and scope for technical studies that define the RTP. These assumptions are described in the RTP Scope and Process document and presented to the stakeholder community at the Regional Planning Group (RPG) meetings. The RPG is responsible for reviewing and providing comments on new transmission projects in the ERCOT region. Per ERCOT Protocols Section 3.11.3, participation in the RPG is required of all TSPs and is open to all Market Participants, consumers, other stakeholders and PUCT Staff. The RTP Scope and Process document can be found in Appendix A.

ERCOT worked with TPs, TOs, and other stakeholders to study the existing system, identify system upgrades and new transmission projects to ensure continued system reliability, and address projected system congestion. Stakeholders and the RPG community were provided routine updates on the input assumptions and supporting analysis performed for the 2015 RTP study in the monthly RPG meetings held from February to May of 2015. Feedback and comments from the RPG were incorporated into the RTP Scope and Process document.

1.3 Assumptions

The RTP study is dependent upon data compiled and provided by numerous parties both inside and outside of ERCOT. The required data include: a forecast of system demand, generation supply and starting network topology. This information is collected and updated each year before ERCOT begins the RTP study per the guidelines from the ERCOT Planning Guide and the RTP Scope and Process document. The following table shows the starting cases used for the 2015 RTP.

Table 1.1: 2015 RTP starting cases

RTP Case	Steady State Working Group (SSWG) Case	SSWG Update
2016 Summer Peak	15DSB_2016_SUM1_TPIT_Final_02242015.raw	February 24 2015
2018 Summer Peak	15DSB_2018_SUM1_TPIT_Final_02242015.raw	February 24 2015
2020 Summer Peak	15DSB_2020_SUM1_TPIT_Final_02242015.raw	February 24 2015
2021 Summer Peak	15DSB_2021_SUM1_TPIT_Final_02242015.raw	February 24 2015
2018 Off-peak	15DSB_2018_MIN_TPIT_Final_02242015.raw	February 24 2015

Each starting case is built per the Steady State Working Group (SSWG) Procedure Manual and represents the most updated system topology and demand forecast as provided by the TSPs. To facilitate transmission planning, ERCOT's transmission system is divided into eight different weather zones to represent the different climate-related weather patterns observed in the ERCOT Region. These weather zones were grouped into study regions, as shown in Figure 1.1, to facilitate transmission planning. For all study years the analysis of the system was grouped into four study regions, defined by weather zones: 1. North and North Central; 2. West and Far West; 3. South and South Central; and 4. East and Coast.

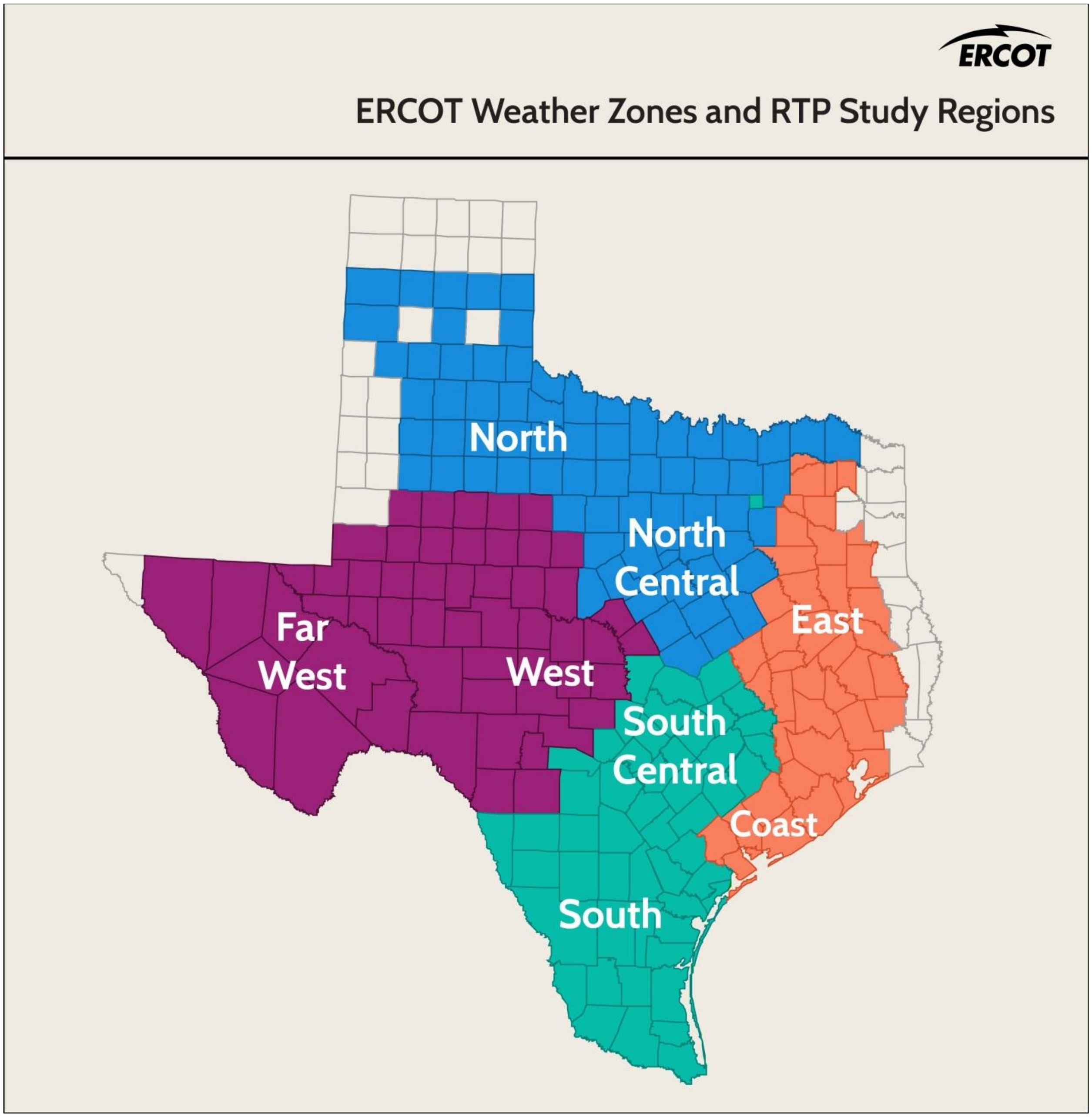

Figure 1.1: 2015 RTP Study Regions

1.3.1 Transmission Model

The SSWG 2015 Data Set B 2016, 2018, 2020 and 2021 summer peak cases, as well as the SSWG 2015 Data Set B minimum load case for 2018 were used as the starting point models for the transmission topology. These cases contain all existing and planned facilities, including reactive power resources and control devices, except as noted below. Additionally, per Section 3.1.4.1 of the ERCOT Planning Guide, the starting base cases for the RTP are created by removing all Tier 1, 2 and 3 projects that have not undergone RPG Project Review from the most recent SSWG cases.

The list of Tier 1, 2 and 3 projects that have not yet received ERCOT review and endorsement and were removed from the base cases is included in Appendix B.

The SSWG start cases are modified based on the guidelines provided in the RTP Scope and Process document to meet the needs of this study. Following is the summary of these model updates.

Transmission Outages

The ERCOT Outage Scheduler was queried to extract a list of planned transmission outages from 2016 through 2021. During this timeframe, there were no planned transmission outages available for modeling as of March 2015.

Base Case Updates and Corrections

Appendix C contains the corrections and updates that were applied to the base cases throughout the RTP analysis.

Protection Systems

A Special Protection System (SPS) refers to a protective relay system specially designed to detect abnormal system conditions and take pre-planned corrective action (other than the isolation of faulted elements) to provide acceptable system performance. The initial analysis of the base cases did not include the effects of any protection offered by SPSs. This test determines the feasibility of exit strategies for any existing and proposed SPSs. SPSs were added to the base cases as problems were identified if no feasible exit strategy could be found. The list of SPSs modeled during the analysis is included in Appendix D.

Base Case Updates for Recently Approved RPG Projects

Projects that received RPG acceptance after the RTP analysis had commenced were included in the cases if they were determined to have material impact on the analysis. A list of these projects can be found in Appendix E.

1.3.2 Contingency Definitions and Performance Requirements

Contingency Definitions

The RTP assesses the ERCOT system for pre-contingency (NERC P0) performance and post-contingency (NERC Categories P1 through P7 and extreme events) steady-state performance.

Table 1 of NERC Standard TPL-001-4 provides the description of each contingency event (P0 through P7 and Extreme Event Contingencies). Each ERCOT TP, via SSWG, provides a database of P1, P2, P4, P5, P7 and Extreme Event (EE2 and EE3) contingencies. In addition to the TP-provided contingency definitions, ERCOT adds multiple element contingency definitions to model P3, P6 planning events and EE1 extreme events. Additionally, a "load throw over" file that models the switching of load from one bus to another following a contingency was used in the reliability analysis. The file is maintained by TPs and is provided in addition to the contingency definitions.

A list of all contingencies for years 2016, 2018, 2020 and 2021 and their corresponding power-flow base cases used in the 2015 RTP are posted on the ERCOT MIS Secure website.

Performance Requirements

All System Operating Limits (SOLs), including Stability SOLs, were respected in accordance with the latest ERCOT System Operating Limit Methodology. All transmission lines and transformers (excluding generator step-up transformers) 60-kV and above were monitored for thermal overloads to ensure that they do not exceed their pre-contingency or post-contingency ratings. Dynamic ratings were used for both the reliability and economic portions of the analysis. The summer peak case ratings were based on the 90th percentile temperature[4] as determined for the weather zone associated with the transmission element. The table below shows the 90th percentile temperatures used to derive the dynamic reliability rating.

Table 1.2: 90th percentile temperatures used in the dynamic reliability ratings calculation

Weather Zone	90th-percentile temperature (°F)
Coast	102.4
East	106.2
Far West	110.4
North Central	108.4
North	109.0
South Central	105.5
South	104.0
West	107.3

[4] Calculated based on the most recent 30-year historical data of annual peak temperatures for each weather zone.

For voltage analysis, all buses 100-kV and above were monitored to ensure that they do not exceed their pre-contingency and post-contingency limits. In addition to the voltage limits, the 2015 RTP also included an analysis of the post-contingency voltage deviation for all buses 100-kV and above. This criteria is defined in the Planning Guide Section 4.1.1.4.

Requirement 3.3.1 of TPL-001-4 requires automatic tripping of elements where relay loadability limits are exceeded. For this analysis, TP-provided relay loadability limits were used when available. In the absence of such ratings, a default limit of higher of the two – 115% of the emergency rating and 150% of normal rating – was used. Additionally, cascading outage analysis was conducted if transmission elements were overloaded beyond their relay loadability limits following a contingency event where load shed is allowed as part of a corrective action plan.

A Panhandle export interface limit of 2763 MW in 2018 and 2904 in 2021 was enforced on the 345-kV double circuit interface defined by the Gray to Tesla, Tule Canyon to Tesla, Cottonwood to Edith Clarke and Cottonwood to Dermott substations while conducting economic analysis. This limit was included in order to represent the stability limit for exporting power from the Panhandle region[5]. The rating in 2021 was updated based on the assumption that the second circuit between Tule Canyon-Ogallala-Windmill-AJ Swope-Gray is added prior to 2021 but no sooner than 2018.

1.3.3 Generation

Generation in the 2015 RTP reliability cases is modeled as per the guidelines given in the RTP scope and process document. The initial generation dispatch information of all existing conventional generation (including natural gas, coal and nuclear) is retained from the SSWG start cases. However, these generators may later be re-dispatched to relieve transmission overloads. Wind, solar and hydro units are dispatched according to the guidelines specified in the RTP scope and process document. Future generation units which meet Planning Guide Section 6.9 requirements are added to the start cases and dispatched according to their

[5] The Panhandle interface limits were calculated using the methodology in the ERCOT Independent Review for Panhandle Upgrades

resource type. A list of future generation included in the RTP start cases is attached in Appendix F.

Wind, Solar and Hydro in economic analysis

In the economic analysis, 8760-hour unit output profiles are used to model the wind, solar and hydro generators' dispatch. ERCOT performed a weather-year analysis using twelve different sets of load forecasts each representing a weather year from 2002-2013. Based on this analysis it was determined that the year 2006 was best-suited to be the representative weather year for the 8760 profiles in the economic analysis. Based on the above analysis, wind profiles from AWS Truepower and solar profiles from URS for year 2006 were used to model wind and solar dispatch in the economic analysis. Hydro dispatch was based on historical hydro output levels from the year 2006.

Mothballed Generation

In accordance with the requirements from the NERC TPL-001-4 standard and the 2015 RTP Scope and Process document, mothballed and seasonally mothballed generation was modeled as out of service when not available for the period under study.

DC Ties

DC tie flows are modeled to match prevailing historical flows during summer peak hours in the reliability analysis. The prevailing historical flows during summer peak hours are full import for the North and East DC ties and full export for the Eagle Pass, Laredo and Railroad DC ties. In economic analysis, profiles to model DC tie flows are created based on historic patterns.

Switchable Generation

Per ERCOT Protocol Section 16.5.4, upon receipt of a written notice, Switchable Generation Resource parameters used in the RTP cases were updated, if necessary, to appropriately reflect the amount of switchable generation available to ERCOT for the study cases.

Firm Transfers

The ERCOT market does not have firm transfers and none were modeled in this study.

Natural Gas Price

Appendix G contains the natural gas price assumption used in the economic analysis.

1.3.4 Demand Forecast

The 2015 RTP utilized two demand forecast sources for the summer peak reliability portion of the study. The first was the bus-level load forecast derived from the Annual Load Data Request (ALDR) and implemented in the Steady State Working Group (SSWG) Data Set B (future year) base cases by the TPs. This load forecast includes the load represented by the TPs and self-served load of customers and is found in the SSWG summer peak start cases. The other demand forecast source was the ERCOT-developed 90th percentile weather zone load forecast. Tables 1.3 and 1.4 show the two sets of load forecasts considered in the 2015 RTP.

Table 1.3: 2015 ERCOT 90th percentile summer peak weather zone load forecast (MW)

Year	Coast	East	Far West	North	North Central	South Central	South	West	ERCOT Non Coincidental Peak Total
2016	23,140	2,350	2,723	1,570	26,299	11,968	6,498	2,013	76,617
2018	23,544	2,357	2,958	1,551	27,002	12,132	6,868	2,053	78,518
2020	23,945	2,363	3,190	1,532	27,688	12,290	7,237	2,092	80,392
2021	24,149	2,370	3,306	1,522	28,032	12,369	7,421	2,112	81,337

Table 1.4: 2015 SSWG summer peak weather zone load forecast (MW)

Year	Coast	East	Far West	North	North Central	South Central	South	West	ERCOT Non Coincidental Peak Total
2016	25,441	2,766	3,251	1,739	24,710	12,810	6,305	2,255	79,278
2018	26,361	2,817	3,583	1,792	25,321	13,392	6,723	2,312	82,300
2020	27,473	2,888	3,804	1,836	25,910	13,970	7,008	2,386	85,274
2021	27,709	2,915	3,912	1,755	26,314	14,296	7,150	2,425	86,476

Upon further analysis of these two sources, it was observed that for two weather zones, the 90th percentile ERCOT load forecast was greater than the corresponding SSWG weather zone forecast. This difference is highlighted in the shaded cells in Table 1.4. ERCOT used the higher of the ERCOT or SSWG load forecast for each weather zone. Using the highest non-coincident load forecast for each weather zone resulted in a simultaneous system demand greater than the amount of generation available to serve the load plus reserves for all of the base cases. ERCOT does not expect that all zones will reach their non-coincident peak loads at the same time so this system-wide load value is assumed to be higher than what would be expected to occur in real-time operations.

Table 1.5: 2015 RTP summer peak weather zone load forecast (MW)

Year	Coast	East	Far West	North	North Central	South Central	South	West	ERCOT Non-Coincidental Peak
2016	25,441	2,766	3,251	1,739	26,299	12,810	6,498	2,255	81,059
2018	26,361	2,817	3,583	1,792	27,002	13,392	6,868	2,312	84,126
2020	27,473	2,888	3,804	1,836	27,688	13,970	7,237	2,386	87,281
2021	27,709	2,915	3,912	1,755	28,032	14,296	7,421	2,425	88,465

The non-conforming flag from ERCOT's operational models was used to identify loads that do not conform to the load changes resulting from weather variations. Each bus in the ERCOT System was assigned an appropriate weather zone profile based on its physical location. The weather zone load from Table 1.5 was redistributed to the individual load level for all conforming loads using distribution factors from the SSWG cases. For the conforming loads in the weather zones outside the region being studied the demand was scaled down to achieve a balance of system-wide load plus responsive reserves and generation. In addition to the summer peak conditions, the 2015 RTP also studied the off-peak conditions for 2018. The 2018 SSWG Minimum load case was used to represent the off-peak conditions as identified earlier in Table 1.1. Table 1.6 shows the load forecast in MWs for the 2018 off-peak case.

Table 1.6: 2015 RTP weather zone load forecast for 2018 Off-peak conditions(MW)

Coast	East	Far West	North	North Central	South Central	South	West	ERCOT Non Coincidental
13,019	1,055	1,893	623	7,465	4,215	3,087	1,005	32,363

For the economic analysis section, the ERCOT developed 50th-percentile 8760-hour weather zone load forecast was utilized for the years 2018 and 2021 based on year 2006 weather assumptions. The year 2006 was determined using the representative weather year analysis mentioned earlier in this report. Additionally, a separate load-specific demand profile is used to model the non-conforming loads. The hourly forecast and demand profile can be found in Appendix H. Table 1.7 shows the peak load megawatts seen in the 50th percentile load forecast. These numbers include self-served and non-conforming loads.

Table 1.7: Peak load from 50th percentile load forecast (MW)

Year	Coast	East	Far West	North	North Central	South Central	South	West
2018	22,700	2,304	2,887	1,552	26,056	11,358	6,609	1,994
2021	23,266	2,323	3,240	1,523	27,081	11,601	7,151	2,053

1.4 Regional Transmission Plan Process

The RTP study process is described in Figure 1.2. Initial start cases to be used in the reliability analysis were prepared in the case conditioning stage. Following case conditioning, reliability analysis is conducted on the base case to determine the transmission upgrades and additions needed to meet ERCOT and NERC reliability requirements. In addition to the base case, the 2015 RTP also includes sensitivity cases, short circuit analysis, cascade analysis and multiple element outage analysis as required by the NERC Standard TPL-001-4. Economic analysis is then conducted to identify transmission projects that allow reliability criteria to be met at a lower total cost.

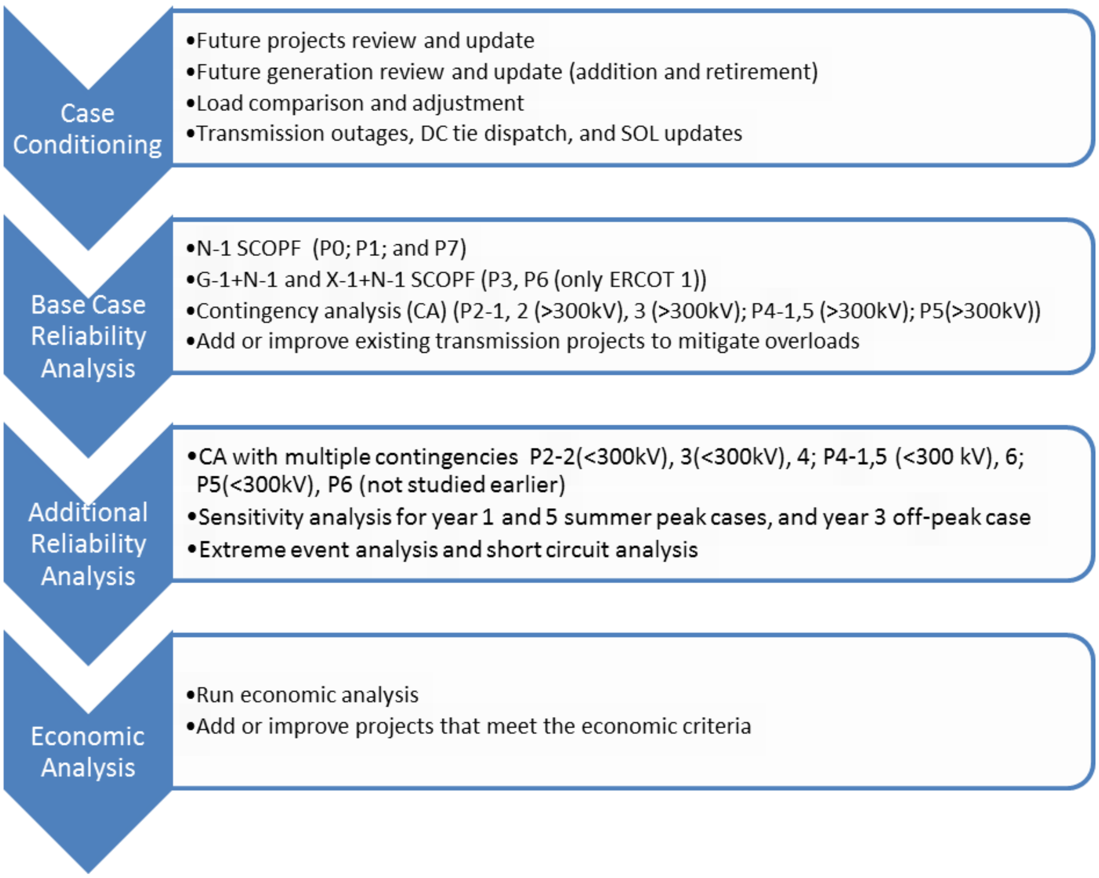

Figure 1.2: 2015 Regional Transmission Plan Process

ERCOT utilized the following software tools while performing the 2015 RTP:

- ✓ PSS/E version 33 was used to develop the conditioned cases and the AC reliability cases
- ✓ PowerWorld versions 17 and 18 with SCOPF and its SIMAUTO functionality were used to perform AC SCOPF analysis and to run generator and transformer outage analysis.
- ✓ TARA version 800 was used to screen critical contingencies while evaluating P3 (Generator outage) and P6-2 (Transformer outage) planning events.
- ✓ POM application suite including Physical and Operations Margin (POM) – Optimal Mitigation Measures (OPM) and Predicting Cascading Modes (PCM) were used to perform load shed analysis, multiple element outage analysis and cascade analysis.
- ✓ UPLAN version 9.04 was used to perform security-constrained economic analysis.

2. Reliability Analysis

Reliability analysis in the 2015 RTP focused on the steady state portion of the NERC TPL standards and the ERCOT Planning Guide. The purpose of reliability analysis is to identify potential criteria violations and future upgrades that may be used to resolve them. Per 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 any re-dispatch of existing or planned generation.

The RTP uses Security Constrained Optimal Power Flow (SCOPF) to identify unresolvable constraints. Loading on BES elements and voltage violations were monitored for all contingency events, including Extreme Events.

Following a contingency where non-consequential load shed was not allowed, Corrective Action Plans were developed per NERC and ERCOT reliability criteria in collaboration with the TPs. The above analysis started with the year six case (2021) and concluded with the analysis of the year one case (2016).

The list of 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 (taking into account necessary lead times). In some cases, the TOs also provided project alternatives. Intermediate and final results were posted on the ERCOT website and presented to stakeholders at regularly scheduled RPG meetings in order to solicit comments and suggestions.

Once feedback was received, the refined sets of improvements were implemented in the base cases. Since many of the upgrades were developed independent of other upgrades, if a project can be backed out and the system could be dispatched such that no deficiencies existed, the project was removed from the reliability-driven project list. The remaining projects formed the final set of the reliability-driven projects. An AC contingency analysis was performed for each of the final reliability cases in order to demonstrate that the reliability criteria were met. The 2015 RTP transmission system upgrades need to be further reviewed by the appropriate TPs to determine the need for an earlier in-service year.

In addition to the above analysis, per the Planning Guide Section 3.1.1.2 (3), the 2015 RTP analysis also included development of a list of transmission facilities that are 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.

In addition to the SCOPF and contingency analyses, the 2015 RTP also included the analyses described in the following sections.

2.1 Multiple element outage analysis

Following a contingency where non-consequential load shed was acceptable, if the total load shed required to reduce the loading on elements below their 100% emergency rating is greater than 300 MW, ERCOT planners investigated the need for a transmission improvement project. For an N-1-1 event, if the total load shed required after the first contingency, but prior to the second contingency, to prevent it from cascading is greater than 100 MW, ERCOT investigated the need for a transmission improvement project. The detailed scope, process, and study methodology of the multiple element outage analysis are documented in a separate report found in Appendix O.

All contingency events where non-consequential load shed is allowed as a corrective action plan were screened to detect potential cascade events for more detailed analysis. The screening to detect a cascade event was initiated by a simulation of events that may result in tripping of system elements based on the following criteria:

- ✓ transmission facilities (100-kV and above) overloaded beyond their relay loadability limits (defined in section 1.3.2)
- ✓ generator buses where voltage on the low or high side of the GSU transformer is less than known or assumed minimum generator under-voltage trip limits
- ✓ generator buses where voltage on the low or high side of the GSU transformer exceeds known or assumed maximum generator over-voltage trip limits
- ✓ buses with known Under Voltage Load Shed (UVLS) protection schemes where voltages go below the under-voltage triggering level

The following criteria were used to identify events causing potential cascading conditions:

- ✓ The total load loss as a result of system cascading is greater than 6% of the total initial system load[6]
- ✓ The power flow does not converge - which may be a result of a potential voltage collapse condition, subject to additional confirmation

The events identified as potential cascade conditions were studied further in co-ordination with associated TPs.

2.2 Sensitivity Analysis

Per the 2015 RTP Scope document, ERCOT selected the summer peak conditions of 2016 and 2020 and off-peak conditions of 2018 for sensitivity analysis as required by Requirement 2.1.4 of the NERC TPL-001-4 standard. The 2015 RTP prepared the sensitivity cases by varying the following set of input assumptions:

- ✓ 10% Reduction in maximum reactive power capability of generators (including all renewables) in the 2016 and 2020 summer peak cases, and
- ✓ High-wind, low-load conditions for the off peak case were studied as a sensitivity of the 2018 off-peak case. Under this sensitivity, dispatch of wind generators was ramped up to a higher level (90% of their maximum MW capacity) and the load levels were scaled up to reflect conditions observed during high wind period consistent with the latest SSWG model[7].

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

2.3 Short Circuit Analysis

Per Requirement 2.3 and 2.8 of TPL-001-4, ERCOT conducted a short circuit analysis based on three-phase to ground fault and single-line to ground fault. The study was performed using the 2018 and 2020 summer peak reliability base cases with all reliability projects identified in the 2015 RTP. Appendix A contains the assumptions used in performing the short circuit analysis.

[6] Based on Section 3.7 of the SOL Methodology for Operating and Planning Horizon
[7] 15DSB_2018_HWLL_TPIT_Final_02242015.raw

The results of short circuit analysis included the magnitude of short circuit current and source impedance associated with each fault; these results were communicated to NERC Registered TOs and GOs. TOs and GOs completed the review of study results, acknowledged the findings and provided a list of over-dutied circuit breakers and corrective action plans.

2.4 Additional Analysis

In addition to the above analysis, the 2015 RTP also studied the following conditions:

- ✓ Per Requirement 2.1.5 of TPL-001-4, the impact of the possible unavailability of major Transmission equipment that has a lead time of one year or more was studied. The studies were performed by starting with an initial condition of the identified long lead time equipment modeled as out of service, followed by contingency events identified as P0, P1 and P2 categories. The list of long lead time equipment was defined based on TO feedback. The results of such analysis were communicated to the appropriate TP organizations.
- ✓ A scenario with all the wind generation inside the study region out of service was performed for all summer peak cases. This analysis was repeated for all four study regions.
- ✓ A scenario in which all Dallas-Fort Worth area generation with no Selective Catalytic Reduction (SCR) were removed from service.

3. Economic Analysis

Economically driven projects are those system improvements that allow NERC Reliability Standards and ERCOT Planning Criteria to be met at a lower total cost (total system variable production cost plus carrying cost of new projects) than the continued dispatch of higher cost generation.

To identify the economically driven projects, a production cost model was prepared based on the ERCOT-developed 50th percentile load forecast, existing and planned generation (meeting the requirements of Planning Guide Section 6.9), and the conditioned topology with the newly identified reliability projects. A list of all congested elements and contingencies causing the congestion was produced by UPLAN. Using this information, a preliminary set of improvements was designed by ERCOT and TPs to solve or reduce the congestion. Projects were put into the model one by one and an annual production cost analysis was performed. Production cost results, before and after the project, were compared to determine the annual production cost savings associated with the project. According to the economic planning criteria described in the ERCOT Protocol Section 3.11.2 (5), economic projects are recommended 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 is assumed to be 15% of the total project cost.

Improvements were evaluated in an iterative process, focusing on the most heavily congested areas in the system first. Projects developed later in the process may impact the economics of those developed earlier since they were developed independently. To ensure that all the potential economically driven projects were still economic with all the other projects in place, a back-out analysis was conducted similar to the back-out analysis performed for the reliability-driven projects. In the back-out analysis, each potential project was individually backed out from the model and tested. Total system production cost before and after a backed out improvement were compared to determine if the upgrade still met the criterion.

After the completion of the back-out analysis, projects that did not pass the economic criterion were removed from the model. Additionally, emissions from all Dallas/Fort Worth area generation units that do not have SCRs were monitored in the course of the economic analysis.

The total NO_x emissions of Dallas/Fort Worth area generation units that do not have SCR did not exceed their environmental restrictions.

The final topology for each year, containing all of the identified reliability and economically driven projects, will serve as the base case for RPG project reviews performed by ERCOT over the next year.

4. Transmission Projects and Mitigation Plans

4.1 Reliability-Driven Projects

Following a contingency where non-consequential load shed was not allowed, Corrective Action Plans were developed per NERC and ERCOT reliability criteria in collaboration with the TPs. These plans included, but were not limited to, upgrades or addition of new transmission facilities. The RTP reliability assessment identified transmission system upgrades for the years 2018, 2020 and 2021 under summer peak conditions and 2018 under off-peak conditions. Reliability concerns for 2016 summer peak conditions were also identified. Since it is not feasible to construct transmission projects prior to the summer of 2016, ERCOT Planners identified potential Constraint Management Plans (CMPs) in collaboration with TPs. These CMPs will be used as placeholder corrective actions until they are reviewed and adopted by ERCOT Operations. These CMPs will be reviewed further in the operations planning horizon by ERCOT and TOs. The list and details about the CMPs identified in the 2015 RTP can be found in Appendix L.

The list and details of the reliability-driven projects identified in the 2015 RTP can be found in Appendices K and T. The majority of planned improvements identified in the 2015 RTP are 138-kV and 69-kV upgrades. Most of the 345-kV projects consisted of either adding a new 345/138-kV transformer or upgrading an existing 345/138-kV transformer. The following table shows the breakdown of transmission upgrades.

Table 4.1: Breakdown of transmission projects identified in 2015 RTP by voltage level

Project type	345	138	69	Total
Transmission Line addition	**1**	**4**	**-**	**5**
Transformer addition	8	2		10
Transmission line/transformer upgrade	**1**	**20**	**11**	**32**
Reactive support addition	4	6		10
Other		**4**	**1**	**5**
Total	13	36	12	62

As seen from Figure 4.1 below, a majority of the transmission upgrades were identified in the South weather zone, which includes the LRGV followed by North Central weather zone, which includes Dallas/Fort Worth and surrounding areas.

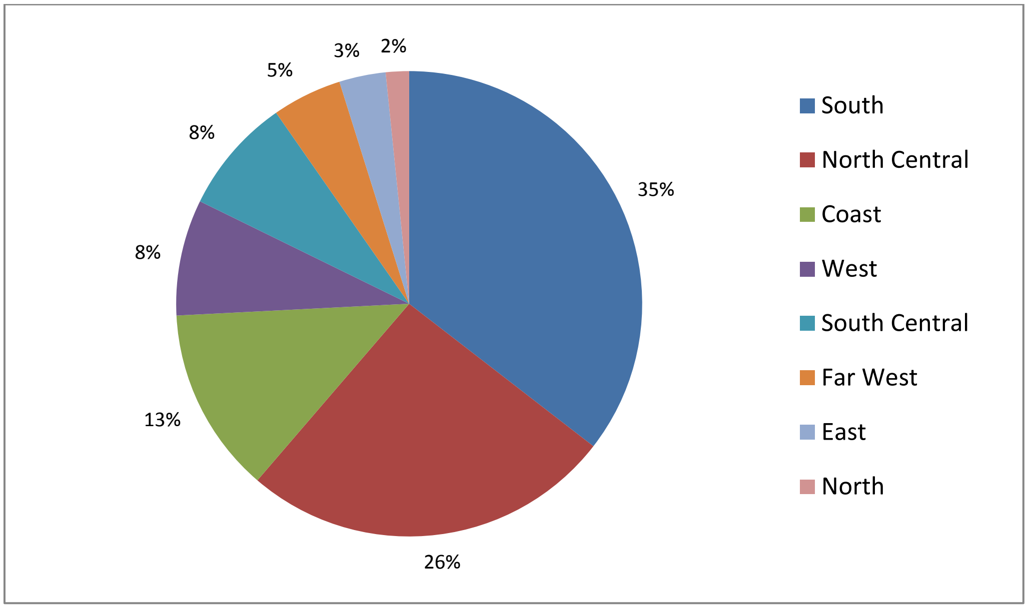

Figure 4.1: Breakdown of transmission projects identified in 2015 RTP by weather zone

The 2015 RTP identified the following noteworthy reliability projects:

- ✓ New 345/138-kV transformer (third transformer) near the Zenith substation in Harris County
- ✓ One additional 345/138-kV transformer at the Palmito Substation in Cameron County in the Lower Rio Grande Valley (LRGV)
- ✓ Upgrade of existing 345/138-kV transformers at the San Miguel substation in Atascosa County
- ✓ A new 144 MVAr reactor at the Kiamichi 345-kV substation in Pittsburg County in Oklahoma
- ✓ A minimum of 50 MVAr reactor at the Clayton 345-kV substation in Fisher County
- ✓ A new second 345/138 kV transformer at the Vealmoor substation in Borden County
- ✓ Cross Valley Tap project which adds a 345/138-kV transformer at South McAllen in Hidalgo County.
- ✓ One additional 345/138-kV transformer in the South McAllen area in Hidalgo County

- ✓ Addition of second 345/138-kV transformers at the Twin Buttes substation in Tom Green County and the Hicks Switch substation in Tarrant County
- ✓ A new 345/138-kV transformer at the Cenizo substation in Webb County
- ✓ A new single-circuit 345-kV transmission line from new North Hill 345-kV substation (near Lon Hill, north of Nueces County) to new Zia 345-kV substation (on the existing Rio Hondo-North Edinburg 345-kV line) in LRGV

A scenario with all the wind generation inside the study region out of service was performed for all summer peak cases. The analysis was repeated for all four study regions. This scenario showed no additional reliability violations.

4.2 Results of Other Reliability Studies

4.2.1 Sensitivity analysis

As indicated in Section 2.1, the impact of the reduction in the reactive power capability of all generators in the ERCOT system was analyzed for the 2016 and 2020 summer peak cases. Table 4.2 below indicates the reactive power capability reduction, which were assumed in the 2016 and 2020 summer peak sensitivity cases.

Table 4.2: Reactive power capability reduction in summer peak sensitivity cases

Weather Zone	2016 (MVAr)	2020 (MVAr)
Coast	**1221**	**1221**
East	493	493
Far West	**253**	**253**
North	424	432
North Central	**870**	**870**
South Central	710	663
Southern	**1135**	**1157**
West	206	205
ERCOT Total	**5313**	**5294**

For the 2018 off-peak conditions, ERCOT analyzed the system impact of the high-wind, low-load conditions. The main purpose of the study, particularly for the 2020 summer and 2018 off-peak conditions, is to evaluate the effectiveness and robustness of the base case reliability projects under the stressed system conditions. Table 4.3 shows the percent of total generation output dispatched by fuel type in the off-peak cases, and Table 4.4 compares the total loads assumed in the two off-peak cases.

As detailed in Appendix M, the result of the sensitivity analysis showed no significant system issues under the stressed system conditions. As such, the reliability projects identified in the 2018 and 2020 base cases reinforce the transmission system sufficiently to handle the changes in the base case system conditions.

The system deficiencies identified in the 2016 summer peak sensitivity case for which system improvements could not be implemented in a timely manner were addressed by CMPs listed in Appendix M.

Table 4.3: Percent of total generation output by fuel type in the off-peak cases

Fuel Type	Percent of Total Output	
	2018 MIN Base Case	2018 HWLL Sensitivity Case
Coal	36.0%	26.6%
Combined Cycle	2.4%	1.8%
Natural Gas (non-CC)	10.7%	9.2%
Nuclear	15.7%	12.5%
PUN	21.4%	16.1%
Solar	0.0%	0.0%
Wind	12.4%	33.4%
Other	1.5%	0.4%

Table 4.4: Total load assumed in the off-peak cases

Weather Zone	Load (MW)	
	2018 MIN Base Case	2018 HWLL Sensitivity Case
ERCOT	32,363	40,019

4.2.2 Short circuit analysis

As indicated in Section 2.3, ERCOT conducted the short circuit analysis for the 2018 and 2020 summer peak base cases with all reliability projects identified in the 2015 RTP. ERCOT worked with Transmission Owners (TOs) and Generation Owners (GOs) to review the fault duty information and to identify substations with over-dutied breakers along with corrective action plans.

Table 4.5 provides a summary of the results of the short circuit analysis. This table indicates that short circuit currents tend to increase as additional transmission elements are added or upgraded over the years. On the other hand, certain changes in the system may result in a decrease in the short circuit current level. As an example, the table shows the number of buses with more than 60 kA decreased by one bus for the single-line to ground fault. This result is primarily due to the retirement (scheduled for Dec 2018) of the J.T. Deely generation, which was modeled offline in the 2020 study case.

Table 4.5: Summary of Short Circuit Analysis

Magnitude of Fault Current	Number of buses (3-phase to ground fault)		Number of buses (single-line to ground fault)	
	2018	2020	2018	2020
Below 40 kA	3730	3749	3983	4007
40 kA ~ 60 kA	434	439	195	197
More than 60 kA	24	25	10	9

Based on the review and comment provided by Transmission Owners (TOs) and Generation Owners (GOs), ten buses were identified as having over-dutied breakers. The buses with over-dutied breakers and the corrective action plans can be found in Appendix N, which also contains the study cases and details of the results.

4.2.3 Multiple element outage analysis

A multiple element outage analysis was conducted for contingencies where non-consequential load shed was allowed as an acceptable Corrective Action Plan. This analysis consisted of 1) load shed analysis, which identified mitigation measures (such as transformer tap setting changes, switching actions, generator re-dispatch and load shed) to resolve any criteria violations resulting from such contingencies, and 2) Cascade analysis, which identified any contingencies that may result in potential Cascade events.

Contingency events which require more than 300 MW of load shed or resulted in a power flow convergence failure were identified as critical contingencies and studied in detail in collaboration with associated TSPs. The criteria used to determine potential Cascade events are defined in the RTP Scope and Process document.

The results of the multiple element outage analysis are documented in a separate report found in Appendix O. This report includes the list of critical contingencies identified as a result of this analysis and any Corrective Action Plans or recommendations to mitigate the impact of these contingencies.

4.2.4 Long lead time equipment analysis

Upon ERCOT's request the Transmission Owners provided a list of long lead time equipment based on their spare equipment strategy. All TSP-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 on 2016, 2018, 2020 and 2021 summer peak conditions, along with 2018 off-peak conditions. In addition to the base case, the sensitivity cases (reduced reactive capability sensitivity for summer peak and HWLL sensitivity for off-peak) were also studied. Overall, twenty-one 345/138-kV transformers and three 345-kV reactors were identified as long lead time equipment. Criteria violations resulting from P0, P1 and P2 contingencies were shared with the respective TPs. The list of long lead time equipment and criteria violations are attached in Appendix P.

4.3 Economic Projects

For years 2018 and 2021 an economic analysis was conducted using production-cost simulation. The input information used in the start and final cases for economic analysis is attached to this report as Appendix H. When applicable, pre-defined SPS's were modeled in the case to relieve congested portions of the network. The list of SPS's modeled in the economic analysis section is documented in Appendix E. After SPS modeling, when congestion persisted, transmission upgrades and additions were tested by comparing the production-cost simulation results for models with and without potential projects. The annual constraint information after SPS modeling is documented in a spreadsheet attached to the report as Appendix I. The economic benefits of each project were measured against the economic planning criteria per the ERCOT Protocol. For this study, the applied economic criterion was the annual production cost savings determined from production-cost simulation needed to exceed the first-year annual revenue requirement for the transmission project (approximately 15% of the total transmission project cost).

Six projects were evaluated using the economic criteria, and one project, namely, the upgrade of the 138-kV line between Solstice and Pig Creek Substations in Pecos County showed enough production-cost savings to justify the project. The analysis also indicated substantial congestion on the Panhandle interface; however transmission upgrades are currently being evaluated as part of an independent project and were not analyzed as part of this study. The list and details of the economic projects tested in the 2015 RTP can be found in Appendix Q.

In addition to the evaluation of economic projects, the 2015 RTP, per the ERCOT Protocol Section 3.10.8.4 (3), identified additional Transmission Elements that have a high probability of providing significant added economic efficiency to the ERCOT market through Dynamic Rating. Dynamic ratings for the identified elements (listed in Appendix R) have been requested from the associated ERCOT TP.

Appendices

<table>
<tr><th>Appendix</th><th>Description</th><th>Document</th><th>Access</th></tr>
<tr><td>A</td><td>RTP Scope and Process Document</td><td>2015_RTP_Scope_Process_V1_0.pdf
2015_RTP_Scope_Process_V1.0.pdf</td><td>Public</td></tr>
<tr><td>B</td><td>Base case updates for projects removed from the SSWG basecases</td><td rowspan="5">CaseInformationUpdates_11122015.xlsx
(File is available in the ERCOT MIS Secure Area)</td><td rowspan="5">MIS Secure</td></tr>
<tr><td>C</td><td>Base Case updates and Corrections</td></tr>
<tr><td>D</td><td>Special protection schemes employed in 2015 RTP</td></tr>
<tr><td>E</td><td>Base case updates for addition of recently approved RPG projects</td></tr>
<tr><td>F</td><td>List of generators added and retired from the SSWG basecase</td></tr>
<tr><td>G</td><td>Natural gas fuel cost forecast</td><td>Appendix G - Natural gas fuel cost forecast.xlsx
Appendix G - Natural gas fuel cost forecast</td><td>Public</td></tr>
<tr><td>H</td><td>Economic analysis input information</td><td rowspan="2">2015_RTP_Economics_FinalCase_Inputs_Annual_Constraints.zip
(File is available in the ERCOT MIS Secure Area)</td><td rowspan="2">MIS Secure</td></tr>
<tr><td>I</td><td>Annual Constraints from 2015 economic analysis</td></tr>
<tr><td>J</td><td>Facilities loaded over 95%</td><td>Appendix_J_2015_RTP_95%_Overload_PG31123.xlsx
(File is available in the ERCOT MIS Secure Area)</td><td>MIS Secure</td></tr>
<tr><td>K</td><td>Reliability Driven Projects</td><td>Appendix_K_2015_RTP_Reliability_Projects_Public.xlsx
Appendix_K_2015_RTP_Reliability_Projec</td><td>Public</td></tr>
<tr><td>L</td><td>Constraint Management Plans</td><td>Appendix_L_2015RTP_CMP_11092015.xlsx
(File is available in the ERCOT MIS Secure Area)</td><td>MIS Secure</td></tr>
<tr><td>M</td><td>Sensitivity Analysis</td><td>Appendix_M_2015_RTP_Sensitivity_Studies_11092015.x</td><td>MIS Secure</td></tr>
</table>

	Results	lsx (File is available in the ERCOT MIS Secure Area)	
N	Short Circuit Analysis	Appendix_N_ShortCircuitStudyCases_DetailedResult.doc x (File is available in the ERCOT MIS Secure Area)	MIS Secure
O	Multiple element outage analysis	Appendix_O_2015_RTP_MultipleElementContingencyStu dyReport.docx (File is ERCOT-Confidential)	MIS Certified (CEII)
P	Long lead time equipment analysis	2015 RTP - LongLeadTimeEquipment.docx (File is ERCOT-Confidential)	ERCOT Confidential
Q	Economic projects evaluated	Appendix_Q-2015RTP_EconomicProjectEvaluations - Public.xlsx Appendix_Q-2015RTP_EconomicProjectI	Public
R	Transmission elements proposed to be dynamically rated	Appendix_R_2015RTP_Transmission_Elements_Recom mended_for_Dyn_Rating.xlsx (File is available in the ERCOT MIS Secure Area)	MIS Secure
S	Project locations	Appendix_S_Project_Location.docx Appendix_S_Project _Location.docx	Public