Long-Term System Assessment
for the ERCOT Region
December 2012

ERCOT Long-Term System Assessment

Executive Summary

Senate Bill 20[1] (79th Legislature, 1st Called Session [2005]) requires that the Public Utility Commission of Texas (PUCT) and the Electric Reliability Council of Texas, Inc. (ERCOT) study the need for increased transmission and generation capacity throughout the state of Texas and report on these needs to the Legislature. A report documenting this study must be filed with the legislature each even-numbered year.

By definition, within ERCOT the bulk transmission network consists of the 69kV, 138kV, and 345kV transmission lines and associated equipment. In planning for both the additions and upgrades to this infrastructure necessitated by our continued robust economic growth, ERCOT has a variety of forward-looking reviews that it conducts to ensure continued system reliability.

The primary venue for the introduction of system upgrades is the Regional Planning Group, which is made up of representatives of the transmission service providers and other market participants. Its role is to provide review of the development of near-term (five-year) transmission plans to address evolving system needs and near-term inadequacies in the system.

ERCOT also completes a Long-Term System Assessment (LTSA) that provides a 10 to 20 year forward-looking assessment of transmission needs. This assessment does not provide specific recommendations for transmission projects. Rather it is used to guide the five-year planning process in two ways.

- First, the LTSA provides a longer term view of system reliability needs. Whereas in the five-year planning horizon a small transmission improvement may appear to be sufficient, the LTSA planning horizon may indicate that a larger project will be required. In this case, the larger project may be more cost-effective than multiple smaller projects, each being recommended in consecutive Five-Year Plans.
- Second, the LTSA can indicate system needs that require solutions that will take longer than 5 years to implement. In such cases, it is desirable to incorporate these projects into the 5-year evaluation process as early as possible.

In addition to the typical 10-year analysis required by Texas Statute, this document also describes a 20-year, forward-looking assessment funded by the Department of Energy that was conducted in parallel with similar assessments for both the Eastern and Western Interconnects.

[1] Public Utility Regulatory Act (PURA) §39.904

Using stakeholder-driven assumptions, a broad range of scenarios were developed to model both expected market conditions and likely resource additions over a 20-year planning horizon. These scenarios were then used to analyze future transmission needs. Based on this analysis, ERCOT has reached the following conclusions:

- The Houston Region will need at least one additional import path within the next ten years.
- Similarly, an additional circuit into the Lower Rio Grande Valley will likely be needed within the next ten years provided that no new generation resources are sited within this region.
- The retirement of legacy gas-fired resources in urban areas due to future market conditions or changing regulatory requirements would lead to an increased need for both expanded import capacity and dynamic reactive resources within the DFW and Houston regions.
- Higher voltage transmission solutions appear cost-effective in future scenarios with significant increases in renewable generation to connect low-cost resources that are concentrated at a significant distance from major load centers.
- Scenario analysis indicates that both natural gas generation and renewable resources are likely to be competitive across a broad range of potential future market outcomes. The prevalence of renewable generation technologies in many future scenarios indicates a need for further study of system requirements to reliably integrate variable generation. As a component of this analysis, ERCOT is currently using grant funding provided by the Department of Energy to implement a new analytical model that will assess the impact of future resource additions on the system's frequency response capability.
- Water availability analysis indicates that sufficient water resources are present within the state to allow the operation of existing and additional future thermal units in the event of extended drought. However, a consequence of extended drought conditions would likely be increased generation development in eastern Texas where surface water resources are more prevalent.

The above conclusions are based on high level assumptions and are intended to inform the five-year planning process, which provides a more detailed review of specific transmission projects. The technologies and locations of generation projects assumed in the analyses that support the above conclusions may not reflect all issues that necessarily must be considered and/or affect generation development decisions. Accordingly, this report is intended to provide guidance to ERCOT and ERCOT market participants in evaluating system needs and is not intended to suggest changes to market policy or support changes to market activities.

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1. Introduction

The Electric Reliability Council of Texas (ERCOT) is a membership-based 501(c)(4) nonprofit corporation, subject to oversight by the Public Utility Commission of Texas and the Texas Legislature. In 1999, the Texas Legislature restructured the Texas electric market and assigned ERCOT the responsibilities of maintaining system reliability through both operations and planning activities, ensuring open access to transmission, processing retail switching to enable customer choice and conducting wholesale market settlement for electricity production and delivery.

In fulfilling these responsibilities, ERCOT manages the flow of electric power to 23 million Texas customers – representing 85 percent of the state's electric load. ERCOT schedules power on an electric grid that connects 40,500 miles of transmission lines and more than 550 generation units. ERCOT also performs financial settlement for the competitive wholesale bulk-power market and administers retail switching for customers in competitive choice areas.

As part of its responsibility to adequately plan the transmission system, ERCOT must develop a biennial assessment of needed transmission infrastructure. Specifically, Section 39.904(k) of the Public Utility Regulatory Act (PURA) requires the Public Utility Commission of Texas (PUCT) and ERCOT to study the need for increased transmission and generation capacity throughout the state of Texas and report to the Legislature the results of the study and any recommendations for legislation. The report must be filed with the legislature not later than December 31 of each even-numbered year.

ERCOT develops two reports to meet this requirement:

- Annual Report on Constraints and Needs in the ERCOT Region – this report provides an assessment of the need for increased transmission and generation capacity for the next five years (2012 - 2017) and provides a summary of the ERCOT Five-Year Transmission Plan to meet those needs (provided under separate cover).
- Long Term System Assessment (LTSA) for the ERCOT Region – this report provides an analysis of the system needs in the tenth year and beyond. The longer-term view in this analysis is designed to guide near-term decisions.

Together, these reports provide an assessment of the needs of the ERCOT system through the next ten years and beyond. This iteration of the LTSA also provides a description of improvements being made to the long-term planning process at ERCOT using grant funding provided to all three grid interconnections in the United States by the Department of Energy (DOE).

2. ERCOT Transmission Planning

2.1 Current Planning Challenges

Planning the ERCOT transmission system is becoming increasingly challenging. The pace of regulatory, economic and technological change of the grid is accelerating. New resource technologies can be developed more quickly than traditional thermal generation, and reduced system generation reserve margins have reduced the time between when a generation project is announced and when it is needed to maintain system reliability. As a result, it is increasingly difficult to ensure that adequate transmission is available in time to move power from new generation sources to load sinks.

Reduced reserve margins also limit the flexibility of system operators to control transmission congestion through unit redispatch. This reduced system flexibility increases the need for transmission upgrades to resolve system congestion.

The challenge of planning adequate transmission may be increased by other factors. Changing environmental regulations (most notably new regulations regarding toxic emissions from coal plants, proposed requirements to reduce impacts of cooling water use on fish populations, coal-ash disposal regulations and greenhouse gas legislation) may lead to the retirement of existing generation. Ongoing drought conditions could result in reduced unit availability as existing units could be forced to reduce output during off-peak or even on-peak hours. An extended drought could result in the retirement of existing resources and could limit locations available for development of future resources. All of these factors could increase the need for new transmission improvements and increase the difficulty in assessing where new transmission improvements would best support system reliability.

Other challenges may emerge in the near future. Analysis documented in this report indicates that the future ERCOT resource fleet may be more dependent on natural gas than the existing generation fleet, as low natural gas prices are expected to limit the development of thermal generation using other fuel sources. This reduced diversity of dispatchable resources will increase the importance of understanding the effects of natural gas pipeline system operations on the electric grid. Increased development of renewable generation is likely under a range of future potential market conditions. The variability and forecasting limitations of these technologies can result in a need for system integration studies and adjustments to system operating procedures. Resources, both generation and demand-side, on the distribution system (non-networked circuits operated at a voltage below 69 kilovolts) may become increasingly prevalent on the system, resulting in a need to evaluate the potential impacts of distributed resources on transmission system operations. In the near future, ERCOT may be increasingly connected to other electrical grids: market participants are currently planning the development of large asynchronous ties between the ERCOT and the eastern and western interconnections. These projects will drive the need to better understand market dynamics outside of ERCOT, and to plan transmission accordingly to serve increased imports and exports.

The greatest challenge to planning the ERCOT system may be how to plan for the unexpected – the event or the trend that appears unlikely now, but could drive system needs more than any issue noted above. All these considerations indicate the need for a robust and dynamic suite of planning processes and toolsets -- a planning tradition that provides assessments of system needs using credible, well-vetted procedures and includes sufficient flexibility to capture a range of possible futures in which system conditions vary substantially from "business as usual."

2.2 ERCOT Planning Processes

The process of planning a reliable and efficient transmission system for the ERCOT Region is composed of several complementary activities and studies. The ERCOT administered System Planning activities comprise near term studies, including the Five-Year Transmission Plan, Regional Planning Group Submissions and review, and Generation Interconnection studies, and ongoing long-range studies, documented in the Long-Term System Assessment (LTSA). In addition to these activities, transmission service providers (TSPs) conduct analysis of localized transmission needs outside of the ERCOT Planning Process.

ERCOT performs its planning function in coordination with TSPs, ERCOT market participants, and other interested parties. ERCOT works with two primary market stakeholder committees in fulfilling its planning responsibilities:

- The Regional Planning Group is responsible for reviewing and providing comments on new transmission projects in the ERCOT region.
- The Planning Working Group is responsible for reviewing the processes and criteria used by ERCOT and by transmission service providers in planning improvements to the ERCOT transmission system.

For the purposes of improving its long-term planning processes, ERCOT created the Long-Term Planning Task Force in 2010, as a subgroup of the Regional Planning Group. This task force has a primary focus on long-range planning activities and assessments.

These planning studies are enabled through the development and maintenance of model representations of the ERCOT grid topology. ERCOT works with owners of transmission, generation and other resources to ensure that the models accurately represent the existing and expected future capability of the thousands of elements that collectively compose the grid. All planned system improvements, including local load-serving projects developed by TSPs outside the ERCOT planning process, are maintained in these system models so that resulting analyses accurately represent future system needs. Recent improvements to the ERCOT model development process have increased the consistency of model databases used to conduct real-time system and market operations, near-term outage management, and near-term and long-range system planning.

Development of the annual Five-Year Transmission Plan is the primary component of the ERCOT near-term planning process. As part of this assessment of region-wide reliability and economic transmission needs, ERCOT works with the TSPs and the RPG to plan improvements to meet system needs for the next five years. In the upcoming installment of the Five-Year Plan, this effort will be expanded to a review of the next six years of transmission needs. The resulting planned improvements address requirements included in the North American Electric Reliability Corporation (NERC) Reliability Standards, and the ERCOT Market Protocols, Operating Guides and Planning Guides. By evaluating system needs in a holistic fashion, that is, by comparing sets of projects that meet all system needs, ERCOT is able to ensure the cost-effectiveness of future system improvements.

Although the goal of the Five-Year Plan process is to review all grid improvement projects in concert, in practice it has not been possible for all necessary system improvements to be reviewed on the same timeline. As system conditions in portions of the grid change (for example recent significant load growth in the oil and gas producing regions of ERCOT), it is often necessary to review regional improvements outside of the Five-Year Plan process. The RPG review process is designed to provide an avenue for the endorsement of these types of projects.

Following the submittal of a proposed project by any RPG participant or market stakeholder, the RPG review process outlines an increasingly rigorous evaluation of the need for the project and cost-effectiveness, based upon project cost and the requirements for regulatory review. Projects that require an amendment to a TSP Certificate of Convenience and Necessity or that are expected to cost more than $50 million are independently reviewed by ERCOT. This independent review will often include an evaluation of project alternatives that achieve the system performance goals of the original project. The project alternative with the expected lowest total cost (including both project cost and expected system operation cost) over the life of the project is recommended, subject to consideration of the expected long-term system needs in the area (as identified in long-term studies), and consideration of the relative operational impacts of the alternatives.

The generation interconnection process is designed to ensure that new generation resources are connected to the existing grid in a reliable manner with sufficient local transmission capacity. Although ERCOT facilitates the interconnection process, the detailed system impact studies are conducted by the TSP that owns and operates the equipment to which the new resource will directly connect. These system impact studies are reviewed by ERCOT and by other interested TSPs. Generation interconnection studies are designed to provide adequate local transmission access and are not used to provide a new generator with full transmission capacity to load centers. As noted previously, regional system improvements are assessed through the Five-Year Plan and individual RPG project reviews.

The Long-Term System Assessment (LTSA) process is based upon scenario analysis techniques to assess the potential needs of the ERCOT System up to 20 years into the future. Due to the high degree of uncertainty associated with the amount and location of loads and resources in the 20-year timeframe, the role of the LTSA is not to recommend the construction of specific system upgrades. Instead, the role of the LTSA is to evaluate the system upgrades that are indicated under each of a wide variety of scenarios in order to identify upgrades that are robust across a range of scenarios or might be more economic than the upgrades that would be determined considering only near-term needs in the Five-Year Transmission Plan development. The LTSA process represents a planning simulation laboratory, in which analysts can model futures that appear possible, unlikely or even extreme in order to highlight fundamental connections between market and regulatory trends and likely system needs, and to assess the effectiveness and usefulness of new planning processes and techniques.

The LTSA guides analysis in shorter-term study horizons through scenario-based assessment of divergent future outcomes. As future study assumptions become more certain, the Five-Year Plan supports actionable plans to meet real near-term economic and reliability driven system needs. In support of stakeholder-identified or ERCOT-assessed projects, the RPG review process leads to endorsement of individual projects that maintain reliability or increase system economy. Finally, the Generator Interconnection Process identifies connection and delivery projects associated with the integration of new resources as they are developed in the ERCOT region. Collectively, these activities create a robust planning process to ensure the reliability and efficiency of the ERCOT transmission system for the foreseeable future.

2.3 ERCOT Planning Reports

The planning studies listed previously are documented in specific planning reports designed to describe the near-term and long-term stresses on and needs of the ERCOT transmission system. The main planning reports produced by ERCOT are: the Seasonal Assessment of Resource Adequacy (SARA); the Capacity, Demand and Reserves Report (CDR); the Constraints and Needs Report; the Five Year Transmission Plan; and the Long Term System Assessment (LTSA). These reports partially satisfy the annual reporting requirements of Public Utility Regulatory Act (PURA) Section 39.155(b), Public Utility Commission (PUC) Substantive Rule 25.361(c)(15) and Substantive Rule 25.505(c). Links to these reports are provided in Appendix 1.

The SARA report provides an assessment of expected resource adequacy for the upcoming two seasons. The SARA report presents a deterministic approach to considering the impact of potential variables that may affect the sufficiency of installed resources to meet the peak electrical demand on the ERCOT System during a particular season. Because this report evaluates expected system conditions less than 6 months into the future, specific information is often available (such as seasonal climate forecasts or anticipated common-mode events such as drought) which can be included to assess the impact on resource adequacy. Sensitivity analyses are developed by varying input assumptions based on historical data, adjusted for any known or expected changes.

The most recent SARA reports (analyzing expected resource adequacy in the Winter 2012-2013 and Spring 2013 seasons) indicate that sufficient resources are available to serve expected system loads across a range of expected system conditions. As noted in these reports, if a higher-than-normal number of forced generation outages occur during a period of record-breaking weather conditions, the ERCOT system could have insufficient resources available to serve resulting demands. While this combination of events is unlikely and would be outside expected planning conditions, the resulting insufficiency could require rotating outages to maintain the integrity of the system as a whole.

The Capacity, Demand and Reserves Report (CDR) documents the expected resource adequacy from one to ten years into the future. This report is based on the industry-standard method of comparing projected load (derived using forecasted economic growth and average weather conditions) to known future resources. A target reserve margin (excess capacity beyond forecasted loads) is developed through a separate loss-of-load analysis to cover the uncertainty in peak demand and resource availability to meet a one-in-ten-years loss-of-load event criterion on a probabilistic basis. Current and expected resources (both generation and demand-side) are accounted for using the methodology defined in Chapter 8 of the ERCOT Planning Guides[2].

The most recent CDR (published on December 10, 2012) indicates that the reserve margin in the ERCOT region is expected to be below the target reserve margin of 13.75% for the 2013 peak season and to remain below that target level for the duration of the reporting period. The planning reserve margin for the peak season of 2013 is expected to be 13.2%. For the peak season of 2014, the reserve margin is currently forecasted to be 10.9%. However, the CDR also notes that three combined-cycle projects are currently under construction and are scheduled to enter commercial operation in the third quarter of 2014. Given their current schedules, these units may be available to provide energy in test mode or may be commercially available by the time of system peak in 2014 (typically in August). As the units will not be available by June 2014, they are not included in the Planned Units (Not Wind) category for 2014. If all three units are available at the time of system peak, the effective planning reserve margin will be 13.6%.

Reduced system reserve margins increase the likelihood of the need to employ rotating system outages during peak load and other resource scarcity conditions in order to maintain overall system integrity. Reduced system reserves also affect system transmission needs. In general, available excess generation provides system flexibility to reduce congestion, in that excess generation can be dispatched up or down to control flows of electricity on congested system elements. During resource scarcity conditions, the availability of excess generation (overall operating reserves) that can be dispatched by system operators is limited, resulting in the increased need for available transmission capacity to resolve system congestion, especially in and around load centers.

The Constraints and Needs Report describes the recent and expected near-term future impact of system congestion. Developed annually, this report describes existing and potential constraints in the transmission system that pose reliability concerns or may increase costs to the electric power market and, ultimately, to Texas consumers. This report summarizes recently completed transmission projects, along with expected future improvements and an analysis showing how those improvements will affect future congestion. In addition, this report shows the need for future projects based on engineering analysis. This analysis includes a review of recent operations and nodal market results and the most heavily congested system elements. Future system needs analysis includes the assessment of the impacts of expected

[2] http://www.ercot.com/content/mktrules/guides/planning/current/08-060112.doc

load growth, future generation interconnections, and retirements. The Constraints and Needs report also summarizes the expected impacts of future transmission projects on system congestion as determined through the Five-Year Plan assessment process.

The Five-Year Transmission Plan report and the Long-Term System Assessment (LTSA) document the input assumptions, methodology and results of these two planning efforts. The Five-Year Transmission Plan report addresses region-wide reliability and economic transmission needs and includes the recommendation of specific planned improvements to meet those needs for the upcoming five years. When system simulations indicate a deficiency in meeting documented planning criteria, a corrective action plan, which typically includes a planned transmission improvement project, is developed.

In contrast, the Long-Term System Assessment (LTSA) does not provide actionable recommendations for specific transmission system improvements. Rather, the LTSA provides general guidance to near-term planning. The LTSA provides an evaluation of the benefits of system upgrades under each of a wide variety of scenarios and in this way identifies upgrades that are robust across a range of scenarios or might be more economic than would be determined if only the near-term needs (as in the Five-Year Transmission Plan development) were considered. The LTSA describes future scenarios that provide a likely boundary for future market conditions and an independent assessment of expected future resources and transmission needs in each future scenario.

The LTSA analysis is based on projections of certain factors that drive decisions on generation investment and system needs, such as the price of natural gas, technology incentives and environmental regulations. These projections are incorporated in an analysis of likely resource expansions (both type and location), which in turn is used to assess system transmission needs.

In addition to these reports, ERCOT has also conducted studies and developed reports in response to specific requests from the PUCT. These studies include assessments of the transmission improvements required to meet legislative mandates (such as studies in support of integrating wind generation in the Competitive Renewable Energy Zones) and the impacts of regulatory changes on expected availability of generation resources (such as recent studies on proposed environmental regulations). Examples of these reports are included in the list provided in Appendix 1.

2.4 Improving the Long-Term Planning Process

Planning for long-range transmission system needs in a deregulated energy market requires a methodology that assesses both commonality and the uniqueness of a wide range of future outcomes. In many instances, particular scenarios create future outcomes that bear little resemblance to any current or near-term study case. For example, twenty years ago, the preparation of an ERCOT future case with more than 10 GW of wind generation would have been considered extreme by many stakeholders, even though this is the resource portfolio serving the ERCOT region today. As it is impossible to know today which of the many possible futures will develop, long-range planning is used as a tool to influence near-term infrastructure improvement decisions through an understanding of commonalities of future system needs across a range of future possibilities. With the increased pace of change in system conditions, long-range planning is increasingly important to ensure adequate lead-time for the development of projects necessary to maintain system reliability.

The time horizon for actionable transmission planning in the ERCOT system is currently five years. For the past six years, every even-numbered year, ERCOT has conducted a 10-year study of system needs. However, this analysis has been limited in scope due to a lack of models, databases, and planning processes specifically designed to support the assessment of long-range system needs. In 2010, ERCOT received grant funding from the Department of Energy (DOE) through the American Recovery and Reinvestment Act (ARRA) to address this need for better long-range planning tools and processes. These funds have been used in a variety of ways to improve long-range planning.

Grant funding was used to develop a tool that simplifies the existing near-term ERCOT planning transmission topology database so as to highlight the need for large, inter-regional system upgrades while automatically resolving the need for smaller, local load-serving projects. This tool has allowed ERCOT to extend the long-range planning horizon beyond 10 years. Current studies such as this LTSA now include an assessment of the potential impacts of up to 20-years of load growth and resource development on the transmission system.

ERCOT used the DOE grant funding to evaluate new software packages, specifically PROMOD IV (PMIV) and the Promod Assistance Tool (PAT), which together provide more capability than ERCOT's existing tools to quantify the market viability of future resource additions. ERCOT used these tools, as well as new processes (developed by grant-funded staff) to better assess system needs over a longer study horizon. ERCOT worked closely with an expanded group of stakeholders to establish several scenarios, based upon underlying market and regulatory assumptions, to develop likely future resource additions based upon each resource technology's market competitiveness. As described in this LTSA, ERCOT developed each future resource portfolio into a model database, to facilitate evaluation of future transmission needs for each scenario.

Grant funding was used to procure additional databases needed to assess the potential impact of variable generation on the ERCOT system. Specifically, ERCOT procured wind generation and solar generation hourly output time series that are chronologically consistent with the 15 years of weather information used by ERCOT to develop load forecasts. Time-synchronized wind, solar, and weather datasets allow ERCOT and other researchers to develop more detailed assessments of the impacts of high levels of variable generation penetration and the benefits of additional technologies in maintaining system reliability.

ERCOT is also using the DOE grant funding to explore the effects of an increased amount of variable generation on the ability of a generation fleet to maintain system frequency. Kermit, a model developed by KEMA that simulates system operations at a multi-second granularity, is being tuned to simulate the existing ERCOT fleet. Kermit will be used in scenarios with increased variable generation to evaluate incremental balancing needs and to update relative resource economics in order to refine the long-term generation expansion process described in this report so as to more fully represent overall system needs.

The current drought in Texas highlights the need for further analysis of water usage by electrical generating facilities and the potential impacts of long-term, sustained drought conditions may have on system reliability. DOE grant funding has supported a detailed analysis of the impacts of an extended drought on the ERCOT system, adapting work completed by Sandia Labs for all of the western United States into a Texas-specific long-term drought scenario with several sensitivities.

ERCOT has also used DOE grant funding to support a Project Facilitator. The Facilitator is responsible for increasing stakeholder involvement in and overall awareness of the role of long-range planning in the ERCOT region. The Facilitator has increased the involvement of experts not traditionally engaged in transmission planning, thereby improving access to additional industry knowledge from stakeholders with knowledge of the ERCOT system. ERCOT has also engaged the Demand-Side Working Group and the Emerging Technology Working Group to build appropriate representations of varying technologies within long-term system assessments.

DOE grant funding is being used to support an evaluation of the current economic transmission expansion evaluation criteria used in the ERCOT planning process, and the appropriateness of this criteria for use in long-range planning. The grant funding is also supporting an analysis of the interconnectedness of natural gas and electric grid infrastructure. Continuing on previous analysis of the adequacy of natural gas pipeline capacity in ERCOT, a study is underway to evaluate how much natural gas pipeline expansion would be necessary to support future scenarios with high levels of new natural gas-fired generation.

In summary, DOE grant funding has allowed ERCOT to significantly improve the long-range planning process for the Texas Interconnection. New toolsets and new processes have been developed, and new databases have been acquired that allow ERCOT, in conjunction with key stakeholders through an enhanced regional planning process, to better understand future transmission needs and to better quantify the benefits of transmission expansion.

3. Future Scenario Analysis

The December 2012 Capacity, Demand, and Reserves Report (CDR) forecasts reserve margins for the next ten peak seasons. This outlook is based on the current status of existing units, the status of units in the generation interconnection queue, and the forecasted demand. The information regarding available generation capacity in the CDR reflects the effects of current and near-term expected market conditions, as generation owners can be expected to construct new generation resources to the extent that these investments will provide an adequate rate of return. However, given the current lead-time for developing new generation projects (three to four years for a combined-cycle unit, two years or less for quick-start gas generation and variable generation resources), the information in the CDR cannot be considered comprehensive for more than four years in the future and likely incomplete for years two through four. As load continues to grow, it is reasonable to expect that new resources will be developed. The question is, what types of resources will be developed, and where?

General modeling assumptions are made to facilitate near-term (five-year) transmission planning given incomplete knowledge of future generation resources. However, for long-range (10 – 20 year) transmission planning, detailed assumptions must be made about the type and location of future resources. This study includes the development of future resources through a scenario-based approach, in which specific market and regulatory assumptions are made to identify probable resource additions. These assumptions include an elevated gas price, the continuation of the renewable generation production tax credit, increased emission costs, and decreased water availability from drought conditions. The resources that are likely to be developed in each scenario are determined through an analysis of expected market conditions using an hourly system dispatch analysis.

3.1 Development of Future Scenarios

Deregulated wholesale electricity markets are intended, in part, to create efficient resource portfolios. An efficient resource portfolio, in economic terms, is one that rewards those who invest in technologies that are most favorable, or competitive, given the prevailing economics and anticipated future outcomes for each technology.

Inherently, uncertainty exists around the profitability of each technology assessed in this study. Fuel prices, future environmental and market regulation, competing technologies, and load growth all affect the profitability of both proposed and existing investments in resources. Accordingly, a long-term transmission plan designed to complement an unknown future resource mix efficiently must consider the likelihood of future technologies proliferating, their probable locations on the ERCOT grid, and relative proportions to the entire resource fleet. To mitigate uncertainty in resource development, a study approach that considers multiple scenarios was utilized.

The interplay of future energy trends is complex. The combination of numerous diverse market forces, changes in natural resource availability, development of new energy sources, and regulatory changes at the local, state, and federal levels make it impossible to predict how the electric system will change over the next 10 to 20 years. As such, in analyzing future system needs, it is necessary to create a variety of potential future scenarios that include assumptions around energy prices, consumption, supply, the advancement and penetration rate of emerging technologies, and the size and cost of energy resources. A full spectrum of probable outcomes based upon current assumptions is likely to be informative of transmission system needs. While the results of this scenario analysis are not definitive statements of what will happen, they do facilitate an understanding of the relationships between market changes and system needs.

ERCOT began the scenario development process by reviewing recently published studies, including reports published by the United States Energy Information Administration (EIA), the International Energy Agency (IEA), Shell, and ExxonMobil. These reports illustrated variants of current and potential future policies and market trends.

ERCOT also reviewed historical data from EIA and the British Petroleum (BP) Statistical Review of World Energy 2010 to develop an understanding of national and global historical trends and relationships. This evaluation included the review of historical production and consumption of energy commodities (crude oil, natural gas, and coal) by country, commodity prices, and economic indicators such as GDP, employment growth rates, and population growth rates.

Following an extensive number of meetings with stakeholders through the Long-Term Planning Task Force and review of numerous comments, a number of scenarios and associated sensitivities were developed for the long-term study. Due to time constraints, only six of these market futures have been completed and are included in this LTSA. The additional scenarios will be analyzed in the coming months and included in future reports.

To provide a reference point for the selection of other future scenarios and to evaluate the effectiveness of the tools used for this study, the Long-Term Study Task Force requested that ERCOT create a Business as Usual (BAU) scenario as the first scenario. This BAU scenario was developed to be consistent with the EIA Annual Energy Outlook (AEO). The BAU is based on the assumption that current policies and regulations will remain in place and that no new policies will be introduced. Commodity prices for natural gas, and coal were obtained from the

EIA AEO 2012 Reference Case (Appendix 2). The load forecast was developed using the ERCOT 2011 long-term load forecast model, based on Moody's 2011 Base Economic Forecast and 15-year average weather conditions.

In the initial stage of this study, wind generation was the only renewable resource that ERCOT had sufficient operational and cost data to fully represent in a model. As the study progressed, ERCOT gained additional information regarding other resources. This led to the development of the BAU with an expanded set of resource technologies (referred to as the BAU with All Tech scenario). The additional technologies included were solar, geothermal, compressed air energy storage (CAES), underground pumped hydro, and some demand response (DR) programs. The solar technology evaluated in the generation expansion process was utility scale photovoltaic (PV).

ERCOT and market stakeholders developed several sensitivities based on the BAU in order to evaluate the impacts of specific input assumptions on generation economics. These sensitivities included:

- Representation of additional non-wind renewable technologies,
- Retirement of all natural-gas-fired units over the age of 50,
- Updated wind patterns reflecting recent improvements in wind turbine technologies,
- Continuation of the Production Tax Credit (PTC) coupled with an elevated natural gas price forecast. (The PTC is a tax credit of approximately $22/Megawatt-hour (MWh; in 2012 dollars) that can be applied to some renewable energy projects for the first 10 years of operation. This tax credit is scheduled to expire in 2012, but can be extended by an act of Congress.)

Prompted by the recent idling and retirement of some older gas-fired units, some stakeholders expressed concern about the effect that additional unit retirements would have on the needs of the transmission system. In addition, a recent report developed by ERCOT indicated that the implementation of new cooling water intake structure requirements could lead to the retirement of almost 10,000 Megawatts (MW) of older gas-fired steam units in ERCOT[3]. As many of these legacy units are located in or near major load centers (many of which are non-attainment zones under the National Ambient Air Quality Standards) redevelopment of these sites with new generation was considered unlikely. The proximity of these legacy units to load centers means that they are relied upon to support system reliability during peak load conditions. As a result, the retirement of these units could increase the need for transmission system improvements.

[3] http://www.ercot.com/content/news/presentations/2011/ERCOT_Review_EPA_Planning_Final.pdf

To assess the impact of multiple retirements of resources located in urban areas, ERCOT developed a sensitivity to the BAU where natural-gas-fired units more than 50 years old are retired. The retirement of coal-fired generation was not included in this sensitivity because most coal-fired generation sites in ERCOT are not located in or around major load centers. As a result, existing coal-fired facilities could be used as locations for future brown-field generation. In this scenario approximately 13,000 MWs of existing gas-fired generation was retired by the simulated year 2032. The list of affected units and dates of retirement are provided in Appendix 3.

In May 2011, ERCOT procured new hourly wind generation patterns based on actual weather data from the previous 15 years. These updated wind patterns include new hourly wind output patterns for 130 hypothetical future wind generation units and were developed using power generation curves consistent with the most recent wind turbine technologies. The 130 profiles were distributed throughout Texas. Each profile is representative of the historical wind output in a specific county. These new wind profiles were incorporated in the Business as Usual with Updated Wind Shapes sensitivity.

A high natural gas price sensitivity was developed to assess the impact of increasing the price of this commodity on scenario results. In this sensitivity, the price of natural gas was increased by $5.00/Million British Thermal units (MMBtu) for all years, and the Federal renewable generation Production Tax Credit (PTC) was assumed to continue beyond 2012.

ERCOT stakeholders were also concerned about the impact that new regulations from the Environmental Protection Agency (EPA) would have on generation in the ERCOT region. The environmental scenario generally accounts for several proposed regulations, including the proposed Cross-State Air Pollution Rule, the Mercury and Air Toxics Standard, and possible greenhouse gas regulation, by imposing emissions costs for sulfur dioxide, nitrogen oxides, and carbon dioxide on generating units and by limiting construction of new coal units to integrated gasification combined-cycle units (IGCC).

In addition, the effects of an extended drought are assessed in the final scenario evaluated as part of this LTSA.

3.2 Resource Expansion Methodology

Determining the likely set of resource expansion units for each scenario requires a multi-step process. For this LTSA, the resource expansion analysis was conducted using PROMOD IV, an hourly economic dispatch model; MarketPower, a monthly project valuation model; a pro forma analysis tool; and an economic retirement analysis tool (Figure 1).

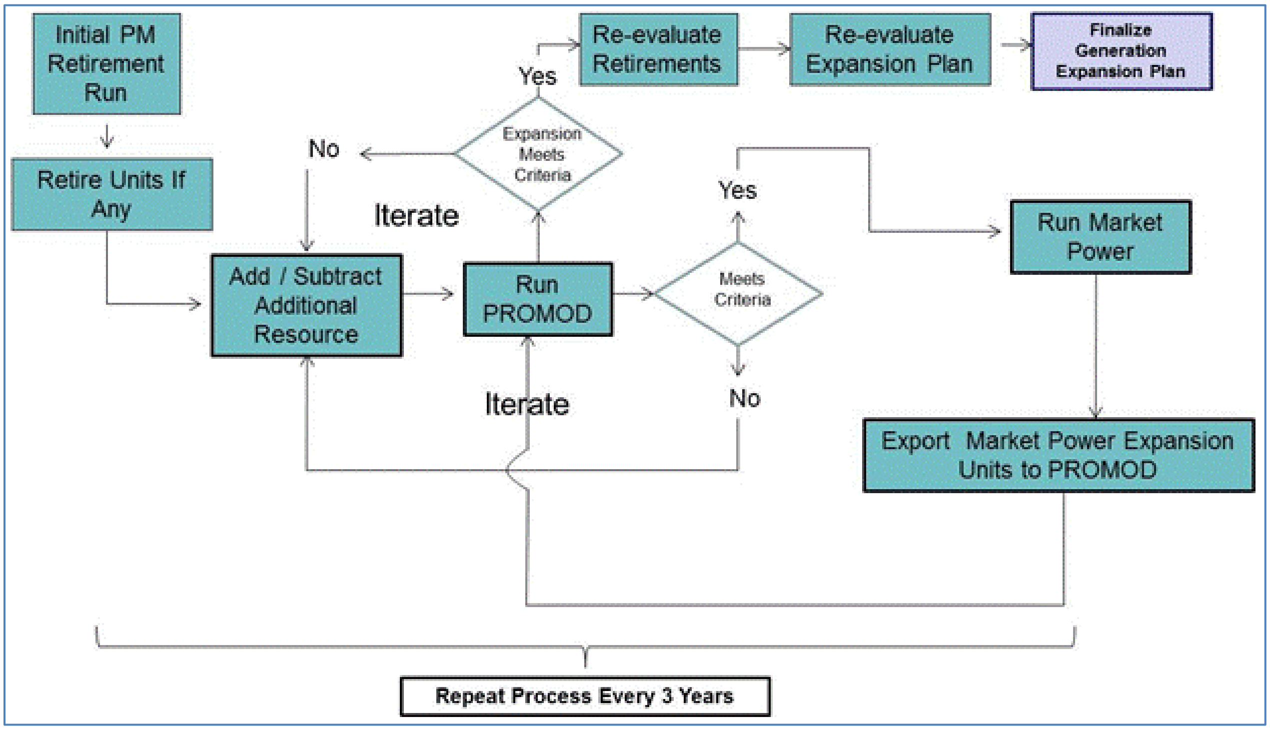


Figure 1: Generation Expansion Process Flow Chart

The energy-limited resources (such as wind or solar generation units) are modeled with an hourly generation pattern consistent with historical weather conditions for a specific location in the ERCOT region. Conventional resources are modeled using variable operation costs to determine an economic dispatch. MarketPower does not account for the hourly generation pattern of wind or solar units. As a result, the market viability of variable generation must be analyzed in an hourly production cost model (in this case PROMOD IV), so that the impact of the hourly generation pattern can be correctly assessed. However, MarketPower is much faster than PROMOD IV and can be used to quickly evaluate the likely market return of a number of generation resources for multiple years.

In addition, a pro forma analysis tool was developed to determine the revenue required for a resource to be considered viable in the market. This tool uses accounting principles with capital costs, fixed and variable operation and maintenance costs, energy produced, and a project financing structure to determine the annual revenue required for the life of the plant. The revenues resulting from the hourly dispatch from PROMOD IV are compared to the requirements of the pro forma analysis tool to make a final decision on which units remain as part of the generation expansion.

As part of the resource expansion process, existing and previously built resources' revenues were evaluated in a retirement analysis tool to determine their future economic viability. The economic retirement analysis tool is an equation that uses weighted values to account for age, efficiency of unit, and profitability.

The generation expansion process was completed using a single bus-type model, which means that it assumes a system with no transmission constraints. Using a transmission-constrained model would have significantly increased the amount of time required to conduct the resource expansion analysis. In addition, in ERCOT, generators do not pay for transmission upgrades. Rather, load customers are responsible to pay for all system upgrades. As a result, it is likely that the locations of future generation development in ERCOT will be more influenced by availability of fuel, water or renewable resource than the cost to upgrade transmission facilities. In order to most accurately reflect this feature of the ERCOT market in the scenario development process, ERCOT decided to conduct the resource expansion process in this study without regard to transmission constraints, to site the resulting future resources using a reasonable set of heuristics, and then to review all transmission needs caused by increased loads and new resources at the same time.

Many of the scenarios developed resulted in reserve margins significantly below the current ERCOT target reserve margin of 13.75%. Yet a certain amount of generation dispatch flexibility (provided by adequate reserve margins) is required in order to conduct transmission planning without exaggerating transmission needs. As a result, additional generation capacity (specifically combustion turbine units), sufficient to achieve a 13.75% reserve margin, was added to the generation expansion build-out before conducting transmission analysis. These administrative units did not provide a significant amount of energy in the models runs conducted as part of transmission planning (each unit had less than 1% capacity factor).

3.3 Resource Expansion Results

A brief description of the generation expansion results for each of the scenarios evaluated in this LTSA follows. Specific details for each scenario are provided in Appendix 4

3.3.1 BAU with All Tech

The BAU with All Tech scenario resulted in the addition of over 20,000 MWs of exclusively natural-gas-fired generation. This scenario is designed to simulate today's market conditions, extended 20 years into the future. The results are consistent with current market outcomes in that most of the new thermal generation in the interconnection queue is natural-gas-fired. In this BAU with All Tech scenario, 500 MW of industrial demand response and 2,200 MW of residential demand response were found to be economically viable given assumed market conditions. This scenario is also marked by significant reductions in future generation reserve margins and a corresponding increase in the number of scarcity-priced hours.

3.3.2 BAU with Retirements

The BAU with Retirements scenario included the retirement of approximately 13,000 MWs of older natural-gas-fired units. These units, listed in Appendix 3, consist primarily of gas-fired steam and combustion turbine units. These units are the most expensive units on the system to operate, and their operation is limited to peak system hours. Retiring these units reduced the system reserve margin, and increased the number of scarcity hours (hours when the market price is set by the System Wide Offer Cap), as evaluated by the hourly system dispatch model. Because these retired units were run infrequently, much of their capacity was replaced in the resource expansion process by gas-fired combustion turbines.

Also, because these system peak hours typically occurred during early to late afternoon hours (when there is high energy output from the sun), 10,000 MWs of solar PV units were also found to be economic. Some combined-cycle units and wind units were also built in this scenario. As in the BAU with All Tech scenario, the expected reserve margin as determined through this resource expansion process declined over time.

3.3.3 BAU with Updated Wind Shapes

The BAU with Updated Wind Shapes sensitivity was developed in order to assess the impact of the new wind patterns which were received following the completion of the analysis of the BAU with All Tech scenario. The updated shapes incorporate recent advances in wind turbine technologies, resulting in increased capacity factors and better economic results for potential wind units in the model results. The updated shapes also have diurnal patterns that better match weather conditions that drive the hourly customer load profiles. The added revenue from these updated hourly generation profiles leads to the addition of almost 17,000 MWs of wind by 2032, compared to no wind generation being added in the BAU with All Tech scenario.

Another interesting finding from this sensitivity is the trade-off noted between combined-cycle units and solar PV units. In the BAU with All Tech, over 13,000 MWs of combined-cycle units were found to be economic. But in the BAU with Updated Wind Shapes sensitivity only 3,600 MWs were economic. In contrast, no solar units were added in the BAU with All Tech scenario, and 10,000 MWs were added in the BAU with Updated Wind Shapes sensitivity. Both wind and solar units are modeled with a variable cost of $0/MWh. As a result, the model will dispatch these units before a combined-cycle unit in the hours that they are available to provide energy. The added renewable generation in this sensitivity results in lower market prices in many hours and lowers the revenue potential for all intermediate and base-load units (including the combined-cycle units). The addition of wind and solar did not seem to affect the economic viability of the combustion turbine units. The likely reasons for this are that the capital cost of the combustion turbine units is lower than wind, solar, and combined-cycle units and that combustion turbine units derive most of their revenue in the model from scarcity hours (i.e., hours in which little or no wind is available to serve load).

3.3.4 BAU with High Natural Gas Price

The BAU with high natural gas price sensitivity is based on the BAU with All Tech scenario, but includes continuation of the PTC, the updated wind shapes, and an increased natural gas price ($5/MMBtu higher in all years). This sensitivity demonstrates the impact of increased natural gas prices and the continuation of the PTC on wind economics. In comparison to the BAU with updated wind shapes, natural gas prices and the PTC improve the market viability of wind units significantly, yielding a wind generation build of over 35,000 MWs of additional wind units by 2032. The increased natural gas prices also lead to inclusion of 3,600 MWs of geothermal resources. Geothermal units can be considered a base load resource because they are estimated to run at a 75 percent capacity factor. For this study, the maximum technical potential of geothermal resources in ERCOT was set at 3,600 MWs based on information provided from Southern Methodist University.

The higher natural gas prices lead to increased dispatch costs for all gas units in the model and decreases the economic viability of new gas resources. Increased gas prices and an increase in the number of off-peak hours with wind on the margin reduced the economic viability of older, less efficient gas units. As a result of these market changes, approximately 5,000 MWs of existing natural-gas units were economically retired in this scenario. These market conditions also led to the development of 13,000 MWs of solar PV units in the sensitivity results. Calculated using wind resources counted at 8.7% of nameplate capacity, reserve margins in this sensitivity declined significantly, although there are other scenarios with more scarcity-priced hours.

3.3.5 Environmental Scenario

A similar result is seen in the Environmental Base scenario: a precipitous decline in reserve margins, but relatively few hours of scarcity pricing. In the Environmental Scenario, over 70,000 MWs of wind capacity is added, along with 18,000 MWs of solar PV. The maximum amount of geothermal resources was added, along with almost 3,000 MWs of combustion turbines and 2,000 MWs of industrial demand response (DR). The combination of high natural gas prices, continuation of the PTC, and increased emission costs (SO_2, NO_X, and CO_2) in this scenario resulted in large amount of renewable resources being built.

The extreme amount of renewable generation included in this scenario is partially a result of the use of an hourly system dispatch model to develop the resource expansion plan. This type of model is blind to intra-hour balancing requirements and the need for commitment of additional resources to limit the impact of variable generation forecasting error consistent with increased levels of renewable generation integration. Future analysis using the KERMIT tool will provide an assessment of the need for additional system dispatch capability in order to integrate levels of renewable resources seen in this and some of the other scenarios.

3.4 Drought Impact Analysis

In 2011, Texas had its worst single-year drought on record, an event that was widely publicized in the news media and was a concern for many water users, including power generators. The average rainfall across the state that year was 14.89 inches, the lowest on record and 0.1 inch below the previous record set in 1917. In addition, the 12-month period between October 2010 and September 2011 was the driest 12-month period ever recorded with an average rainfall of 11.18 inches across the state.

These drought conditions resulted in ERCOT developing an ongoing assessment process of generator water reservoir levels. Using the results of these assessments, monthly drought status updates are provided to ERCOT stakeholders and the impacts of drought conditions are included in the Seasonal Assessments of Resource Adequacy (SARA), which ERCOT issues quarterly. ERCOT also worked with the Western Electric Coordinating Council (WECC), Sandia National Laboratories (Sandia) and Argonne National Laboratory to study the effects of long-term drought on power generation facilities throughout the western United States. This study was based on an analysis of surface hydrology, streamflow modeling, and reservoir storage. Groundwater, wastewater, and brackish groundwater costs were also included in this analysis.

Initial review of survey data provided by the generators and the actual unit history from 2011 have shown that most generators are prepared or have contingency plans for moderate or even short duration severe droughts such as the conditions experienced in 2011. The more complex issue for generators in Texas appears to be a multi-year drought, such as the drought that occurred in Texas between 1950 and 1957. While the 1950 – 1957 drought was not as severe on an individual year basis as 2011, it is still the period of record for extended drought across most of the state.

To complete an assessment of the potential impacts of a multi-year drought, ERCOT contracted with Black and Veatch (B&V) to review and extend the Sandia results. B&V reviewed current water costs by ERCOT-designated weather zone by water-usage type, including agricultural, raw water, treated water and wastewater. Water cost information from municipalities and water authorities was reviewed. B&V also examined the need for additional infrastructure should new sources of water be required, and historical weather patterns by ERCOT weather zone.

This review evaluated three main combinations of ERCOT weather zones which roughly delineate the water availability by region as shown in Figure 2. In general, average annual rainfall amounts are highest in the east and southeast of the state, with rainfall averages decreasing to the west. Also shown in Figure 2 are the locations of existing ERCOT generating resources.

In order to include the impact of future drought conditions on likely resource development, projected water cost adders were developed for each technology. These additional costs were included in the generation expansion process. As an example, water-cost adders for combined cycle units across the weather zone regions are provided in Table 1.

By reviewing water supply availability data and reviewing annual and monthly rainfall patterns, reservoir/lake levels and withdrawals, and surface water temperatures, B&V developed assumed capacity derations to existing thermal generation units in the event of a long-term drought. Figure 3 shows the cumulative capacity derations of existing ERCOT resources over the last three years of an extended drought.

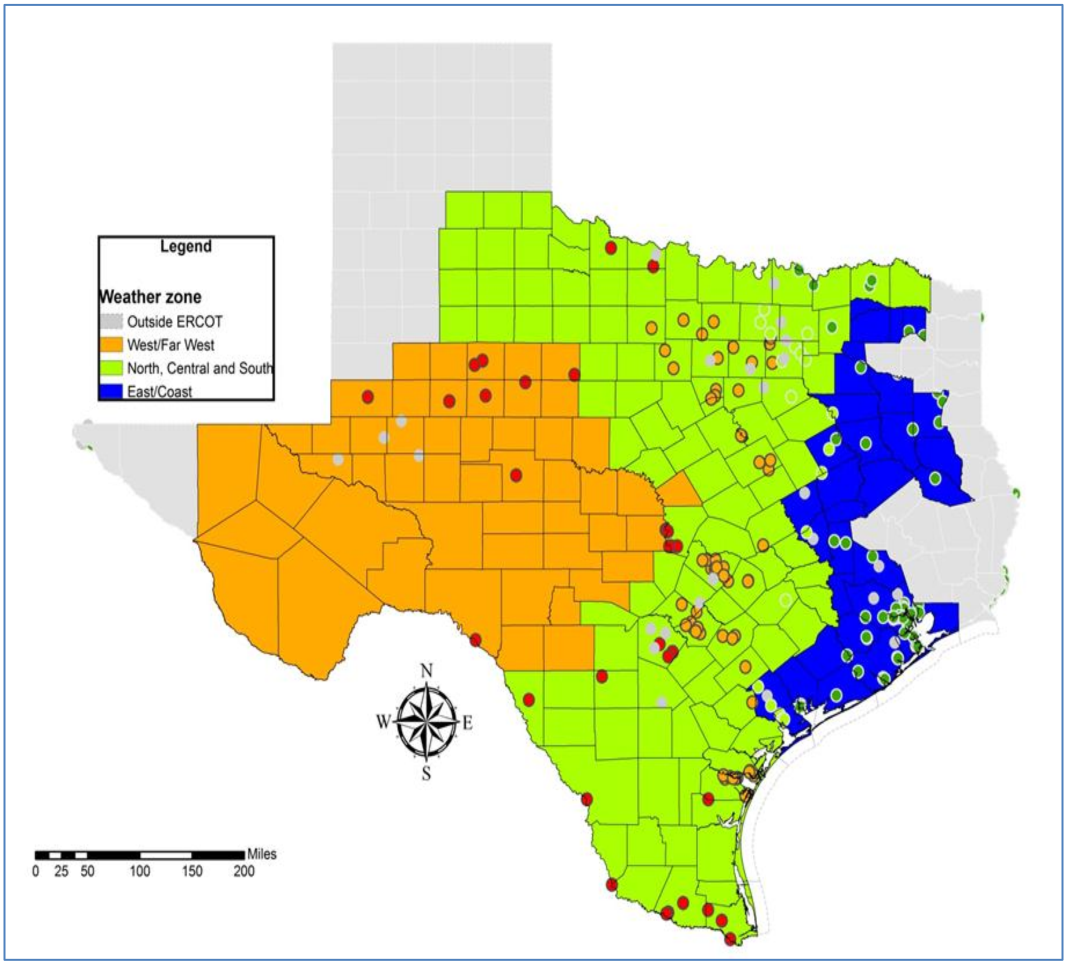


Figure 2: Water Cost Regions

Using this information, an Extended Drought scenario was developed. This scenario was based on resources defined in the BAU with All Tech scenario and included expected load growth consistent with Moody's 2011 base economic growth forecast.

The Extended Drought scenario included two changes from the BAU with All Tech scenario. First, capacity reductions for all existing thermal generation units were applied during the period of the drought (assumed to be from 2019 through 2025) due to lack of water at existing plant sites and increased intake/discharge water temperatures. Second, additional costs for acquiring water were included for new thermal generation expansion units.

Weather Zone	$/MWh
COAST	$0.22
EAST	$0.24
NORTH CENTRAL	$0.36
SOUTH CENTRAL	$0.38
NORTH	$0.44
SOUTH	$0.48
WEST	$0.63
FAR WEST	$0.76

Table 1. Water cost adders by weather zone for combined-cycle units

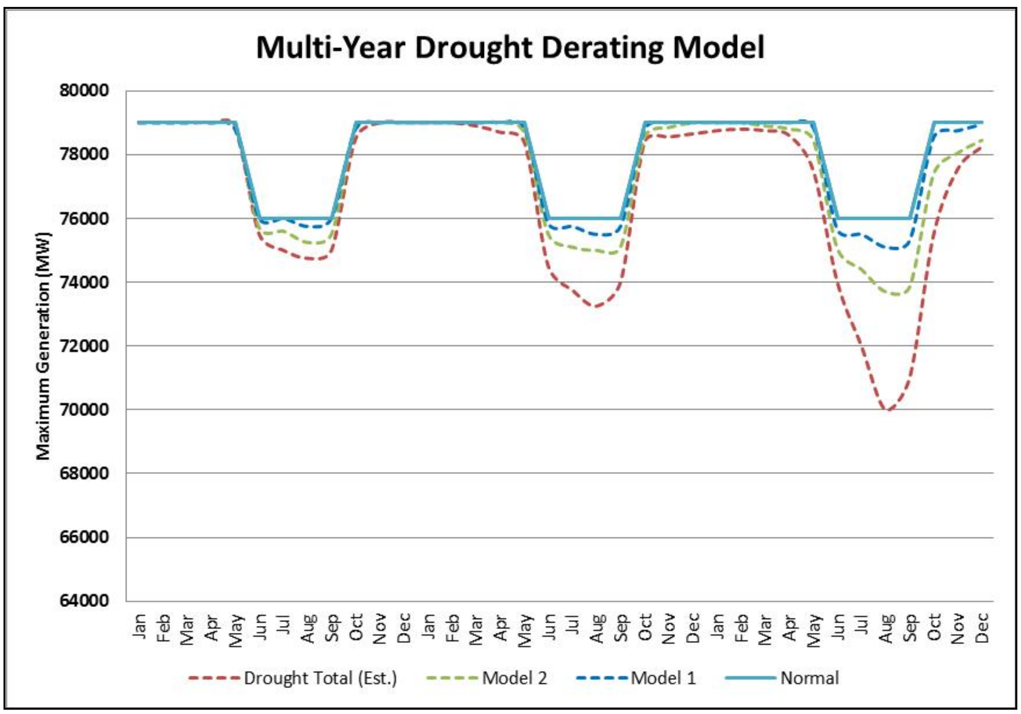


Figure 3: Multi-year drought capacity model results

Overall, the drought scenario analysis indicates that sufficient water resources are present within the state to allow the operation of existing and additional future thermal units. However, it is likely that extended drought conditions will lead to changes in geographic considerations for future thermal unit development. The increased availability of surface water resources in eastern Texas is likely to lead to a prevalence of generation development in that area.

The expansion plan for the Extended Drought scenario was the most diverse as it included combined cycles, combustion turbines, geothermal, wind, solar PV, and industrial demand response (DR). Despite including additional water costs to expansion units without dry-cooling technology, revenues of a combined cycle with dry-cooling technology were not competitive. Analysis indicates that the cost of water would need to rise to approximately $2.50/MWh for a combined cycle with dry-cooling to be built.

3.5 Assessment of Operational Reliability

Resource expansion studies conducted using hourly dispatch simulation models fail to capture the impact of future generation additions on the resulting system's ability to maintain operational reliability. In order to address this model limitation, ERCOT used grant funding from the Department of Energy (DOE) to procure a tool that will determine the ability of a portfolio of resources to meet current system balancing requirements. In scenarios where economic assessment of current and emerging technologies suggests increasing proportions of non-traditional resources are likely, ERCOT is developing scenario-specific studies using this tool.

System frequency response adequacy is a second-to-second metric driven by technology specific response and availability characteristics. Analyzing the ability of a resource mix to comply with current balancing metrics requires an equally granular second-by-second time series simulation of events. Accordingly, ERCOT has procured the Kermit model to assess the ability of the combined fleet to meet reliability metrics, including frequency response, Area Control Error (ACE), and disturbance control standards (DCS). This model has been calibrated against recent operational events. In the next stage of implementation, the model input database will be expanded to represent hypothetical future resource expansion scenarios.

Wind generation dominates future resource builds in scenarios with market or regulatory conditions favoring renewable resource additions. The Environmental Scenario suggests that over 70 GWs of wind generation may be present on the ERCOT system within the next 20 years (based solely on evaluation of hourly system dispatch). The resultant system simulation exhibits hourly net-load ramps in excess of 12 GW. The Environmental Scenario represents an opportunity to use the Kermit model to assess the ability of current ancillary service products and procurement practices to balance the net load changes in real-time, and to identify complementary regulation resources needed to meet existing balancing and frequency control standards.

As the cost of ancillary services increases with increased demand to balance intermittent renewable output, the economics of a resource portfolio may change. For example, if thermal dispatchable resources generate an increasing percentage of their revenue from ancillary services, then emerging storage technologies may become more competitive. Conversely, if no competitive procurement process can yield sufficient system ramping capability, then further integration of renewable resources may impair system reliability. Either study result should trigger a re-assessment of each technology assumed to be economic in a scenario. The re-assessment will consider the economy of every resource inclusive of ramping needs, ancillary service revenue, and the resultant competitiveness of each technology.

ERCOT is continuing this analysis as part of the DOE-funded planning enhancement activities and on-going long-range planning studies. Assessing both the system ancillary service needs and the resultant shift in resource economics is expected to indicate type and size of technologies required to maintain system balancing capability, and how system balancing (regulation service) revenues change the resource value proposition. This assessment could also help identify cost-effective changes to ancillary service procurement practices, should variable resource integration in ERCOT continue.

3.6 Discussion

The scenarios described above have been developed in order to provide potential resources to be included in transmission needs analyses. By developing a range of scenarios, the intent is to define the range of potential future outcomes rather than to predict what will occur. In addition to supporting the transmission planning process, the development of these future scenarios and assessing likely resource additions by scenario provides useful information on its own.

Perhaps the most notable feature of these scenario results is their similarity: natural gas generation and renewables dominate the expansion mix for all of the sensitivities. In sensitivities in which market prices are expected to stay low and no incentives are provided for renewable generation, most or all of the expansion units are fueled by natural gas. In scenarios with increasing market prices (due to increased fuel costs, emissions allowance prices, etc.) renewable generation additions are significant. As modeled, the capital costs for pulverized coal, integrated gasification combined-cycle, and nuclear units are too high for them to be competitive under the future scenarios evaluated.

The prevalence of renewable generation in future resource additions indicates a need for additional studies regarding the operational requirements for integrating higher levels of variable generation. The prevalence of natural-gas generation in scenario results and the potential reduction in diversity of thermal resources supports a recommendation for further studies regarding the inter-dependencies between the electrical grid and the natural gas pipeline system.

Another consistent result from the scenario analysis is declining reserve margins over time. There are several reasons for this result. The hourly load forecasts used in this scenario analysis are based on average weather conditions over the past 15 years. These average weather conditions do not include extreme conditions that would drive a greater than expected number of scarcity hours. During periods of resource scarcity (i.e., hours in which there is not enough generation capacity to serve load), prices are set administratively. In this scenario analysis, the market cap was set at $3,000/MWh (this cap on market prices was recently increased in the ERCOT market by the PUCT). These administratively-set scarcity prices are the primary source of income for peaking capacity and allow expansion units in the model to obtain sufficient revenue to provide an adequate rate of return on capital investment. The use of average weather conditions results in reduced return on investment in the model and thus lower reserve margins.

The hourly system modeling approach used in this scenario analysis also does not take into account scarcity conditions that occur in the sub-hourly real-time markets and does not include ancillary services revenue (for spinning reserves, regulation, and for non-spin service). These additional sources of unit revenue could provide sufficient economic justification for additional future units to be added had it been included in the analysis.

Overall, the results of this scenario analysis are generally consistent with the recently completed Brattle study of ERCOT market conditions (ERCOT Investment Incentives and Resource Adequacy, June 1, 2012[4]) which concludes that scarcity pricing, even with higher market price caps than used in this analysis, does not provide sufficient revenue to maintain the current ERCOT target reserve margin of 13.75%.

[4] http://www.ercot.com/content/news/presentations/2012/Brattle%20ERCOT%20Resource%20Adequacy%20Review%20-%202012-06-01.pdf

Reserve margins as low as those developed through economic analysis of future generation additions are insufficient to conduct a thorough analysis of transmission needs. In order to develop adequate input datasets for the transmission models, additional units (consisting entirely of low-capital cost combustion turbine units) were added to each scenario, as needed, as part of the development of the base transmission planning case. Even though they were required in order to evaluate the need for transmission improvements, these administrative units did not operate above a 1% capacity factor in the transmission analysis model runs.

Another feature of many of these scenario results is the amount of renewable units that get added to the existing resource mix. The reason for this is likely that these future renewable generation units are competing based on energy revenue in many hours against existing generation sources, much of which is natural-gas-fired combined-cycle units. As they have little or no variable costs to operate, the total cost of energy from renewable units results from the cost of construction and resulting capital investment costs. In scenarios in which the variable cost of energy from combined-cycle units exceeds the "all-in" (i.e., inclusive of capital costs) energy cost of renewable generation, renewable units are competitive with over half of the energy sources in the existing ERCOT fleet. These economics result in significant increases in renewable generation in some of the scenarios.

These scenario results also show the impact of improved wind turbine technologies. The initial scenarios were evaluated using older wind generation patterns, obtained by ERCOT in 2006 from AWS Truepower. New wind generation patterns were obtained from AWS Truepower in July 2011, and while these new patterns are modeled using similar locations and similar historical meteorological data as the old patterns, they incorporate power generation curves consistent with the latest turbine technologies. The result is increased annual capacity factors and more energy provided during peak hours for the expansion wind units. The resulting improved economic results for these expansion wind units led to an increase of 17 GWs of wind generation being economic in the scenario results (comparing the BAU with All Tech scenario to the similarly derived BAU with Updated Wind Shapes sensitivity). The Federal Production Tax Credit (PTC), a tax credit currently equal to approximately $22/MWh, increases these economic impacts in any scenario in which it is included.

The increased wind generation during peak hours also led to fewer scarcity hours, which, in the resource expansion analysis methodology developed for this study, are the primary source of revenue used to recover the capital costs of expansion thermal units. As a result, scenarios with aggressive expansion of renewable resources were also characterized by significantly reduced reserve margins (the amount of resources above the expected peak customer demand). To some extent these low reserve margins are a result of the use of the administratively determined capacity value of wind (currently set at 8.7% for the ERCOT region) in the reserve margin results as reported. Based on these scenario results, a review of the impacts of the new wind generation turbine technologies on the capacity value of wind may be warranted as part of the next round of loss-of-load studies.

In future studies, ERCOT will be able to use the results of the Kermit model to reflect the increased cost of ancillary services in scenarios with increased penetration of renewable generation (see Section 3.5 for more information on this software). Another area of interest is quantifying the risk associated with increased variable generation resources due to the inherent error in forecasting variable generation output hours or even one day in advance. Current production-cost modeling tools do not adequately account for this forecasting risk in assessing the need for additional committed generation resources, or in assessing the value of quick-start generation and dispatchable demand-side resources. These economic adjustments will likely result in additions of technologies that directly support reliable integration of renewables (such as energy storage units) in some scenarios or reduced additions of variable generation due to increased costs and the need to increase the commitment of dispatchable generation to maintain system reliability.

In the Environmental scenario, emissions costs were included to simulate the impacts of the recently proposed Cross-State Air Pollution Rule, the Mercury and Air Toxics Standard and potential limits on emissions of greenhouse gases. While these regulations are currently in various stages of development, implementation, or legal review, this scenario is intended to indicate their cumulative impacts. As the resulting emissions costs lead to increased operating costs for coal, combined cycle and combustion turbine units (and thus higher market prices in all hours), these assumptions lead to an aggressive expansion of renewable generation units. These results are consistent with the results from other scenarios.

4. Transmission Needs Analysis

4.1 Methodology

The base case for transmission analysis by scenario was developed from the final year of the Five-Year Transmission Plan. Loads in the case were increased as anticipated in the ERCOT Long Term Forecast for the region, disaggregated by weather zone, county, and bus. The network was simplified to increase focus on issues relevant to a long-term planning horizon (ten to twenty years).

Scenario-specific portfolios of incremental resources were added to the base case to support anticipated load growth. As described in Section 3, these portfolios were created based upon an economic assessment of the viability of emerging or existing resource technology given scenario-specific assumptions. The resources were installed in the case at bus locations presumed to be favorable to the technology (for example, wind resources would be installed at buses near favorable wind generation sites, thermal units would be installed in close proximity to fuel source, water, transmission, etc.) with favorable locational marginal prices (as simulated in a production cost model run).

ERCOT created a representation of the base case with increased system loading, Five-Year Transmission Plan transmission network, and existing and economically justified future resources in a load-flow model to simulate the desired years of study. Overloaded elements requiring upgrades regardless of system dispatch were addressed and documented as reliability upgrades. Reliability upgrades were compared to other alternatives that were found to resolve the same issues possibly at lower overall cost at later stages in the study.

ERCOT also studied voltage stability constraints, with emphasis on transfer limitations into major ERCOT load pockets. For each scenario, ERCOT determined the point at which incremental transfers into the relevant load pockets would be at or near voltage collapse, under contingency. This evaluation of interface limits was used to (1) identify options to support incremental transfers with reactive support devices and lines and (2) respect import limits corresponding to voltage stability. The voltage stability constraints imposed in each scenario are documented in Appendix 5.

At the completion of the analysis of upgrades required to maintain system reliability, each resulting "reliability case" was used as a starting case to identify opportunities to improve system economic efficiency. System analysis began in areas of high congestion where conceptual projects were designed to attempt to reduce system production costs sufficiently to offset each project's total cost to customers.

Reliability-driven projects and economic alternatives or supplements were documented separately and provided to near-term planning groups for consideration in shorter-term study horizons. Near-term planning studies (e.g. the Five-Year Plan) will reference long-term reliability constraints in the area of proposed projects.

Cost estimates for potential transmission projects used in this study do not reflect routing considerations, such as unknown obstacles, physical constraints, or public preferences. These routing obstacles can lead to significant project cost increases. Additionally, as the length of a proposed line increases, the impedance of the circuit increases. As impedance increases, the usefulness of the circuit as a new path between two or more points on the ERCOT system decreases. Reliability and economic benefits of a conceptual project decrease as costs and line length increase. To account for these potential deviations, the length (and impedance) of each conceptual project considered in this study that required new right-of-way was increased by 30% (based on analysis of recent transmission projects). In addition, to represent the cost disparity associated between urban and rural right-of way acquisition, estimates of per-mile costs for urban transmission expansion were increased by 40% over the costs of rural transmission expansion projects.

4.2 Study Results by Region

Transmission study results are presented by region across a range of scenarios, and then by scenario across the system as a whole. Detailed results are presented in Appendix 5. When viewed in isolation, the results from each scenario indicate transmission projects required to serve forecasted loads given scenario specific resource expansions (generation type and location). When viewed as a composite whole, these scenario results indicate underlying system needs that will have to be considered as part of future near-term studies.

4.2.1 Houston Metro Region

ERCOT observed the need for expanded import paths into the Houston Metropolitan Region in every scenario studied in the context of this LTSA. In most scenario base cases, existing import paths into Houston were overloaded within the 10-year initial planning horizon.

To develop a reliable base case for the 10- to 20-year horizon, new import pathways or upgrades to existing 345kV import paths into the Houston region were required. Although they were considered options for this long-term study, the upgrades of existing 345kV import lines into Houston may not be possible. The Houston region is highly dependent upon imported power, most notably from the north; though significant imports occur from the south and west (the eastern side of Houston borders the neighboring Eastern Interconnection with no synchronous ties to ERCOT). The Houston region's current dependence upon existing import lines would make scheduling the outages needed to facilitate an upgrade of an existing major import pathway difficult.

Many of the market scenarios studied included expansion generation near but not within the immediate Houston area (due to the siting limitations caused by NAAQS non-attainment status). Even so, the 345kV lines that carry imported power from north of the area into Houston, specifically both Singleton to Zenith lines, Roans Prairie to Kuykendahl, and Singleton to Tomball were consistently either overloaded or heavily congested. Imports into Houston from around the South Texas Project / Dow Chemical area (southwest of Houston) were also consistently overloaded in each scenario base case.

Additionally, voltage stability limits were exceeded in all of the studied scenarios. In the most extreme scenario, BAU with Retirements, in which legacy natural-gas fired units were retired upon their 50th anniversary of commercial operations, voltage collapse was imminent for certain single contingencies before 2022. ERCOT assessed a variety of system solutions to address this reliability need.

ERCOT considered multiple solutions to the Houston Import constraint to evaluate relative cost-effectiveness. Passive solutions, such as increased dynamic and static reactive support, were studied to the extent that such solutions were operationally achievable. Power factor assumptions, load distribution assumptions, and dynamic/static reactive resources may alter the timing of the need for new or expanded import paths. These solutions were particularly effective where stability limits were more constraining than the thermal limitations of the region and neighboring strong sources were far away. However, in certain scenarios, the reactive power consumption associated with heavily loaded, long lines exceeded what was generally acceptable as an operable level of static or dynamic reactive support. ERCOT worked closely with Transmission Service Providers (TSPs) to establish reasonable approximations of maximum achievable reactive support before investigating new transmission line solutions. Working collectively with TSPs, ERCOT developed solution sets inclusive of new lines and reactive support that achieved relevant reliability requirements.

Consistent with ERCOT's established planning processes, reliability base cases were used to evaluate opportunities to improve the economic efficiency of the ERCOT System. For the Houston Import issue, multiple projects in several scenarios not only maintained reliability but also returned production cost savings commensurate with the ERCOT economic planning criteria. Notably, Houston import projects were economic between 2022 and 2032 in several scenarios, including the unit retirements scenario and the high natural gas price scenario. In both scenarios, nearly all import options demonstrated cost-effectiveness when included in system topologies within the 10-year study horizon (see Appendix 5 for detailed project results.)

The results from the various scenarios evaluated are consistent and clear: the Houston Region will need incremental or expanded import capacity absent a significant amount of generation development within the area. Additional dynamic reactive support may delay the need, though certain scenarios demonstrated that the level of reactive support needed to ensure reliability without expanded imports may not be operationally achievable. For most scenarios no reliable dispatch was achievable without expanded Houston import paths. In several scenarios, Houston import projects returned production cost savings in excess of their total cost to consumers. ERCOT will continue evaluating Houston import options and ensure that the results are incorporated in shorter-term study horizons.

4.2.2 Dallas/Fort Worth Region

The Dallas/Fort Worth Region (DFW), unlike many other urban load pockets within ERCOT, does not have a well-defined boundary (from an electrical topology perspective). Characterized by two major cities with blurred borders and overlapping growth, DFW's expanded import needs are unique. Historic import corridors were typically east and southeast of Dallas and south of Fort Worth, where legacy gas and coal units provided significant support to the region. Transmission line connections to the DFW region from these plants were sized to accommodate the generators in an era of integrated resource planning.

The resultant topology is dependent on energy injections at or near existing sources for reliability. Generation expansion or repowering at existing plant locations could reduce the need for major transmission improvements. Given these considerations and the uncertainty inherent in planning adequate transmission for a deregulated wholesale electric marketplace, the benefits of an extra-high voltage loop around the DFW region were evaluated. Such a loop would provide new connection points for thermal generation, as well as contingency mitigation for the loss of any one connection to the loop. The resulting flexibility in the transmission system appeared to be most beneficial in scenarios in which future resources are likely to be developed south and east of DFW.

In contrast, scenarios modeling large increases in installed wind capacity in west Texas showed little need for expansive transmission projects in the south and eastern areas of DFW as less thermal generation was added in these areas. Full build-out of the Competitive Renewable Energy Zones (CREZ) created a strong generation source west of DFW and resulted in an efficient delivery of power through CREZ connections to DFW load. Scenarios without a strong western generation source required reliability upgrades to existing south and east import paths to accommodate forecasted load growth in the DFW region.

From a stability perspective, most scenarios demonstrated that incremental import paths into Dallas would be required outside of the 10-year study horizon. In several scenarios, moderate additions of static or dynamic reactive resources improved stability margins in a cost-effective manner. The most severe need for expanded imports into Dallas was observed in the Retirements Scenario, though it occurred after 2022. Multiple import paths were needed in Dallas before 2032 to support voltage stability.

From an economic perspective, congestion into Dallas was primarily located south and southeast of Dallas. This congestion was generally attributable to hypothetical generation expansion sites south and southeast of Dallas and the limited existing infrastructure to deliver the new, low cost resources to DFW load. No upgrades associated with this congestion were uniformly recognized across scenarios or consistently met ERCOT's economic criteria. Thus, it is expected that new import paths into the DFW area will be identified in a shorter-term planning horizon when generation siting location assumptions are better known.

4.2.3 Austin/San Antonio Region

The Austin Metropolitan region, as modeled, shows increasing dependence upon 138kV infrastructure connecting to the 345kV system east of the load pocket to serve growing loads to the extreme west of the load pocket. Disproportionate load growth in counties west of Austin led to an investigation of opportunities to introduce a western 345kV source to support future needs.

From a reliability and voltage stability perspective, the existing infrastructure with incremental upgrades to existing 138kV circuits was capable of supporting projected loads through the ten-year study horizon. Over the 20-year course of this study, several 138kV circuits became overloaded and required upgrades to create a reliable case. In light of these overloaded circuits, ERCOT investigated several options to bring new 345kV sources into the Austin Area. In this analysis these alternatives were not cost-competitive with upgrading existing 138kV infrastructure. However, the feasibility of the upgrades shown to be needed is not known at this time. Further analysis is required to verify the cost-effectiveness of these upgrades.

San Antonio (SA) is notably different from other load pockets within ERCOT, possessing a well-defined extra high voltage (EHV) loop around the metropolitan area. This loop is generally adequate to serve load growth in the region within the 10-year study horizon.

From an economic perspective, the "life-lines," (Hill Country – Marion, Skyline – Marion) connecting the EHV SA loop to the 345kV corridor which runs parallel to I-35 (Hutto to Clear Springs) exhibits significant congestion across multiple scenarios. Limited options to redispatch resources internal to the loop to offset post-contingent overloads for the loss of either of these two circuits resulted in significant congestion. This was most evident in the retirement scenario, where fewer thermal resources are available to alleviate congestion. Conversely, in wind-heavy scenarios, the CREZ connection west of San Antonio (at Kendall) delayed import needs to at least 2032. ERCOT assessed multiple options to add additional connectivity to the 345kV ring and mitigate the individual impact of a contingency to any 345kV circuit connection to the ring. System upgrades on all sides of the 345kV ring were evaluated. While all of the new connections to the 345kV ring evaluated did not provide sufficient economic savings to be considered economic, study results indicate that upgrading either of the existing 345kV connections would meet ERCOT's current economic criteria. At this time it is not known if upgrading these circuits is possible given the likely duration and outage requirements of such a project.

4.2.4 Lower Rio Grande Valley

The Lower Rio Grande Valley (LRGV) area is located at the southernmost portion of the ERCOT region along the international border with Mexico. It includes the cities of Edinburg, McAllen, Harlingen, and Brownsville. The LRGV area is experiencing high rates of population and economic growth and consequently a high rate of electric load growth. Currently, the load is primarily served by local natural gas generation and power imports from the rest of the ERCOT system. The two existing major 345kV import paths are the Ajo - Rio Hondo and the Lon Hill - North Edinburg 345kV lines.

The recent ERCOT independent review of the LRGV area indicated the need for a new 345kV line from Lobo to North Edinburg to improve the power transfer capability to the LGRV and to increase the maintenance window for the two existing 345kV circuits. The new circuit is scheduled to be in-service by 2016.

While the new connection from Lobo to North Edinburg will be constructed as a single-circuit, it will be placed on double-circuit capable towers. As the addition of a second circuit then becomes the most cost-effective option to increase import (and export) capability from the

LRGV area, ERCOT evaluated when the second circuit from Lobo to North Edinburg could become necessary to maintain local voltage stability. This study assumed that the recently Regional Planning Group (RPG)-approved Cross-Valley project is in-service. Transmission needs were evaluated with and without proposed block load additions assed by the RPG (based upon estimates provided by the Brownsville Public Utility Board).

This analysis indicates that the second circuit would be needed for voltage stability by 2021 without the addition of the block load, and assuming no new resources are sited in the region. Should the block load addition materialize, the second circuit will be needed earlier. Initial estimates of the block load addition provided at the time of this study indicated that up to 250 MW of industrial development is possible (although after the completion of this study, the block load estimate was revised to 150MW). Assuming the 250 MW block load addition, the second Lobo to North Edinburg circuit would be required as soon as 2016. With or without the block load addition, the second circuit would be required within the 10-year study horizon, assuming no new generation resources are developed in the LGRV area.

4.3 Study Results by Scenario

4.3.1 BAU with Retirements

ERCOT's robust marketplace has caused a repowering of much of the resource base that historically served load within the region. The remaining legacy units, built in a regulated era to serve major metropolitan areas within the ERCOT footprint, are notable exceptions. As Dallas, Houston, Austin, and San Antonio become increasingly urban, redevelopment and expansion of existing and/or new resource construction in these areas may face both public opposition and increased environmental scrutiny. These legacy units have become critical contributors to the reliability and stability of major ERCOT load centers. The BAU with Retirements scenario was developed to assess the impact on system transmission needs of the retirement of these older units.

In this scenario, retirement of gas-fired units over 50-years in age removed both reactive support and redispatch options from heavily loaded urban regions. As part of this scenario it was assumed that sites located within National Ambient Air Quality Standards non-attainment zones were not eligible for redevelopment. The resultant loss of resources is depicted in Figure 4.

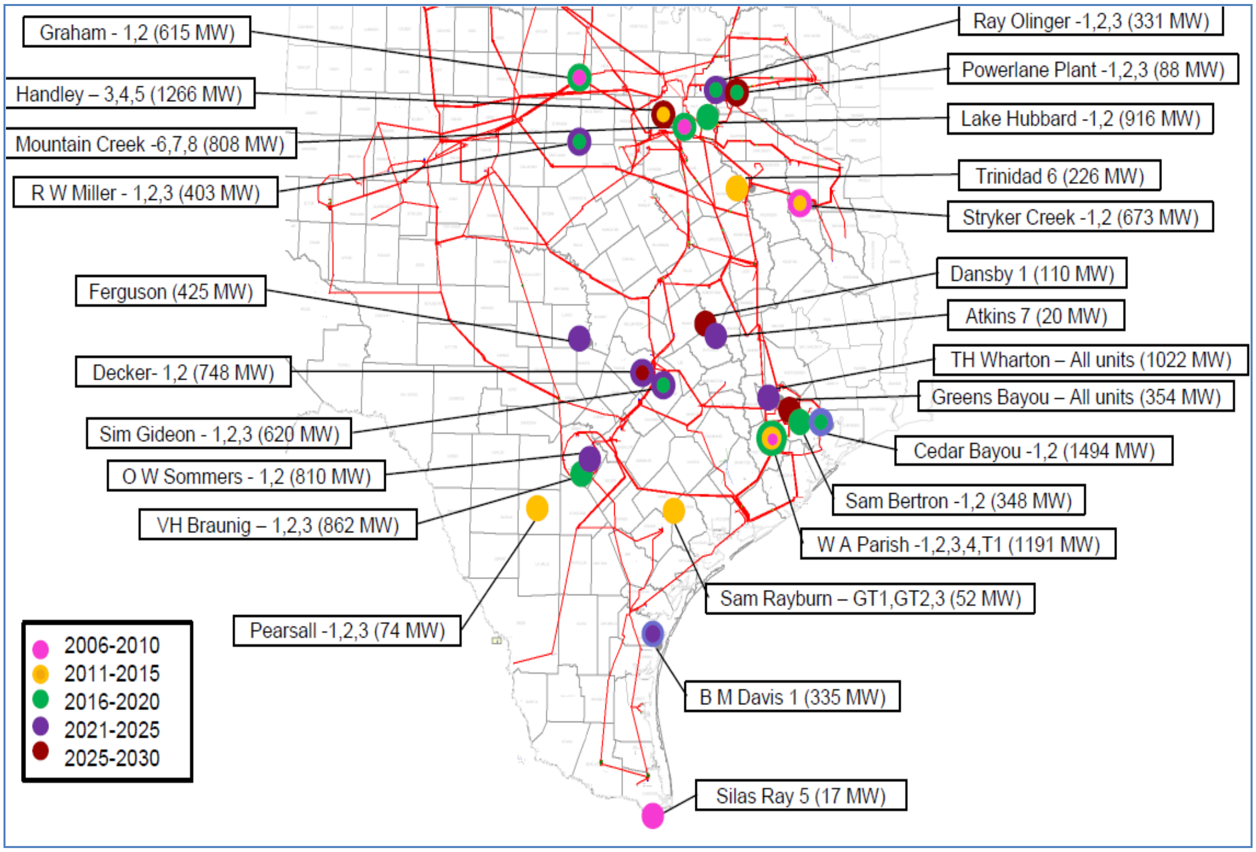


Figure 4: Location of Unit Retirements

All major ERCOT load pockets experienced significant resource retirements in this scenario. Each load pocket suffered a decrease in real and reactive power sources, decreasing both local generation and import capabilities on a pre- and post-contingent basis. In general, transmission needs (both for new import pathways and increased autotransformer capacity) increased by approximately 30%. The resultant loss of resources was most notable in the DFW and Houston metropolitan regions. The lack of critical reactive resources threatened stable operations as early as 2018 in the Houston region. Analysis conducted as part of this study indicates that the loss of this generation could not be offset by addition of dynamic reactive devices in the urban centers. Rather, new import pathways would be required.

This scenario was used to generally characterize the dependence upon legacy generation sites and to build an understanding of the relationship between urban unit retirements and additional transmission needs that can be used to study conditions in near-term studies after actual unit retirements are announced. The DFW and Houston metropolitan regions will each need multiple new import lines without timely and suitably located development of new sources of generation (i.e., a combination of continued operation of legacy resources, redevelopment of existing resources and/or development of new resources within each load pocket). The base case development for Houston included new import paths before 2022. Thereafter, new import lines would be needed by 2027 and 2030, to allow for approximately 2 GW of gas-fired resources to retire upon reaching 50 years of commercial operation. The DFW region was less affected. Base case development required the upgrade of one existing import path. DFW retirements were more prominent in the 2022-2032 timeframe, calling for incremental import paths by 2029 and 2032 for stability, following retirements of 1.4 GW of gas-fired capacity. Retirements in this scenario could affect reliability in the Austin and San Antonio regions by 2028 and 2024, respectively.

The retirements in all regions created significant increases in congestion rents. The Houston area import paths were among the most congested on the ERCOT system. Given the reliability need to increase import capability into the region for steady-state stability, conceptual economic projects were developed. Multiple Houston import projects were found to be economic by 2022.

The retirement scenario, though extreme, illustrates the dependencies and transmission needs associated with a hypothetical retirement of the "legacy" gas-fired generation. Should changing regulations, low natural gas prices, or resource competition threaten the economic viability of these units, transmission infrastructure expansion requirements would be significant. Houston would need multiple new import paths within the study horizon of this report. DFW would also need at least one expanded import path within the same time frame.

4.3.2 Scenarios with Increased Renewables

Several of the scenarios described in Section 3 result in large amounts of new renewable resources over the next 10 to 20 years. The transmission analysis of these futures was designed to identify complementary system needs to ensure a reliable, cost-effective integration of future renewable resources.

A significant expansion of wind resources is a feature of the BAU with Updated Wind Shapes, the BAU with High Gas Price, and the Environmental Scenario. General findings from these scenarios are as follows:

- A strong CREZ system with total wind resources nearing 18,500 MW capacity (as designed) greatly negates the need for south and eastern import pathways into the DFW metropolitan region.

- At wind levels beyond CREZ design specifications, remaining weak connections to the DFW region must be upgraded. CREZ facilities that were designed to be double-circuit capable, but built as a single circuit line, will require the second circuit to accommodate wind beyond original design specifications. In several resource expansion studies, this need occurred before the year 2022.
- If the northwestern-most portion of the Panhandle CREZ system becomes over-subscribed, voltage stability limits will constrain wind power delivery to the rest of the ERCOT system. Some of the highest-quality wind sites occur at the outer-most borders of the ERCOT system in the Panhandle region.
- Based on steady-state model analysis, if potential wind output from the Panhandle region exceeds 6 GW of exports, then one or more additional export lines from the Panhandle will have to be evaluated. Figure 5 depicts preliminary projects that are currently under review. The preliminary reliability and economic assessments of these projects is included in Appendix 5

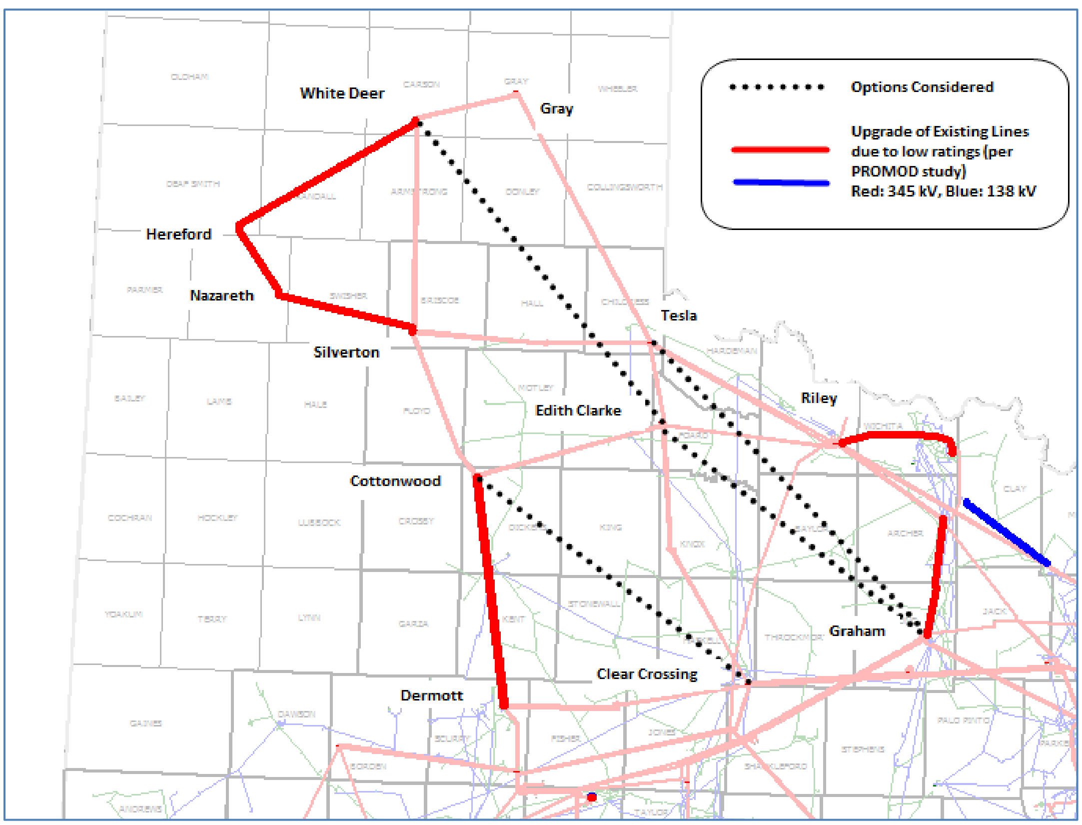


Figure 5: Panhandle Transmission Expansion Projects Reviewed

4.3.3 Extended Drought Scenario Analysis

Water availability and expenses (for new resources) modeled in an Extended Drought scenario steered thermal expansion resources to the eastern borders of the ERCOT system. The resulting concentration of thermal expansion units to the east and southeast of Dallas and to the north and northeast of Houston resulted in increased power flows on the existing import paths into both the Dallas and Houston load pockets. Further, without incremental resource development in the Southern Region of the ERCOT System, the Houston area became increasingly dependent upon the imports from the north.

Additionally, the Extended Drought scenario included an anticipated increase in peak loading, primarily associated with assumed increased air conditioning load. The net effect of the water costs and increased loading accelerated the need for an additional import circuits from the North into Houston and from the South into Dallas. If extreme drought conditions prevail and resource expansion is primarily in the Eastern Region of the ERCOT system, then new and upgraded imports in to Houston and Dallas will merit further study.

4.3.4 High natural gas prices

In this scenario ERCOT modeled a potential future in which natural gas prices return to levels comparable to those seen in 2008. With this significant increase in natural gas prices, resource expansion portfolios heavily favored renewable resources, including wind, geothermal, and solar-photovoltaic. New gas-fired thermal resources added to the scenario reduced the economic return derived from existing legacy gas-fired units, resulting in unit retirements.

From a transmission needs perspective, an increase in natural gas prices, as modeled in this scenario, would have a net effect of retiring urban/legacy gas units and expanding wind beyond the designed capacity of the CREZ System. Retiring urban/legacy gas-fired units would expedite the need for expanded import capacity in major load zones. Incremental resources connected to the CREZ system impose new stability constraints on delivery of Panhandle wind power to the rest of the ERCOT system.

Should wind interconnections in the Panhandle region exceed 10GW, coincident with high natural gas prices, higher-voltage transmission solutions become economically viable and merit further review. ERCOT studied various 500kV and HVDC options to determine the economic viability of such projects. Several projects demonstrated sufficient economic benefits (i.e., met ERCOT's current economic planning criteria) when utilized to connect Panhandle wind resources to Central Texas, DFW and Houston.[5] These results differ from recent near-term planning studies in which the cost of 500kV and 765kV has eclipsed the benefit to consumers using ERCOT's established economic planning criteria.

Increased natural gas prices also increased congestion rents as higher-cost marginal gas units were needed to relieve transmission constraints. Accordingly, multiple projects increasing imports into Houston, Dallas, and Central Texas demonstrated sufficient economic benefits to be considered viable alternatives.

[5] Note: These DC Production Cost Models did not consider operational or technical considerations for incorporating higher voltages and/or HVDC.

5. Conclusions

As described in this report, ERCOT has conducted an analysis of the needs of the ERCOT transmission system through the year 2032. Using stakeholder-driven assumptions, a broad range of scenarios were developed to model both expected market conditions and likely resource additions over a 20-year planning horizon. These scenarios were then used to analyze future transmission needs. Based on this analysis, ERCOT has reached the following conclusions:

- The Houston Region will need at least one additional import path within the next ten years.
- Similarly, an additional circuit into the Lower Rio Grande Valley will likely be needed within the next ten years provided that no new generation resources are sited within this region.
- The retirement of legacy gas-fired resources in urban areas due to future market conditions or changing regulatory requirements would lead to an increased need for both expanded import capacity and dynamic reactive resources within the DFW and Houston regions.
- Higher voltage transmission solutions appear cost-effective in future scenarios with significant increases in renewable generation to connect low-cost resources that are concentrated at a significant distance from major load centers.
- Scenario analysis indicates that both natural gas generation and renewable resources are likely to be competitive across a broad range of potential future market outcomes. The prevalence of renewable generation technologies in many future scenarios indicates a need for further study of system requirements to reliably integrate variable generation. As a component of this analysis, ERCOT is currently using grant funding provided by the Department of Energy to implement a new analytical model that will assess the impact of future resource additions on the system's frequency response capability.
- Water availability analysis indicates that sufficient water resources are present within the state to allow the operation of existing and additional future thermal units in the event of extended drought. However, a consequence of extended drought conditions would likely be increased generation development in eastern Texas where surface water resources are more prevalent.

The above conclusions, and this report in general, are based on high level assumptions and are intended to guide the five-year planning process, which provides a more detailed review of specific transmission projects. The technologies and locations of generation projects assumed in the analyses that support the above conclusions may not reflect all issues that necessarily affect generation development decisions. Accordingly, this report is intended to provide guidance to ERCOT and ERCOT market participants in evaluating system needs, and is not intended to suggest changes to market policy or support changes to market activities.

Appendix 1: ERCOT System Planning Reports

Recent System Planning Reports:

Report on the Capacity, Demand, and Reserves in the ERCOT Region, December 2012 (Winter Update)

Seasonal Assessment of Resource Adequacy for the ERCOT Region, Spring 2013

Seasonal Assessment of Resource Adequacy for the ERCOT Region, Winter 2012 - 2013

Report on Existing and Potential Electric System Constraints and Needs, December, 2012

These reports are available at http://www.ercot.com/news/presentations/ under the Operations and System Planning heading.

Reports on the impacts of pending environmental regulations:

Impacts of the Cross-State Air Pollution Rule on the ERCOT System, September 1, 2011
Link: http://www.ercot.com/content/news/presentations/2011/ERCOT_CSAPR_Study.pdf

Review of the Potential Impacts of Proposed Environmental Regulations on the ERCOT System (Revision 1), June 21, 2011
Link: http://www.ercot.com/content/news/presentations/2011/ERCOT_Review_EPA_Planning_Final.pdf

Analysis of Potential Impacts of CO2 Emissions Limits on Electric Power Costs in the ERCOT Region, May 12, 2009
Link: http://www.ercot.com/content/news/presentations/2009/Carbon_Study_Report.pdf

Reports on the transmission improvements necessary to support the designation of Competitive Renewable Energy Zones:

Competitive Renewable Energy Zones (CREZ) Transmission Optimization Study, April 2, 2008
Link: http://www.ercot.com/content/news/presentations/2008/ERCOT_Website_Posting.zip

Analysis of Wind Generation Impact on ERCOT Ancillary Services Requirements, March 28, 2008
Link: http://www.ercot.com/content/news/presentations/2008/Wind_Generation_Impact_on_Ancillary_Services_-_GE_Study.zip

ERCOT CREZ Reactive Power Compensation Study, December 3, 2010
Link: http://www.ercot.com/content/news/presentations/2011/CREZ%20Reactive%20Power%20Compensation%20Study.pdf

Appendix 2: Commodity Prices for Scenarios

Natural Gas and Coal Prices by Scenario

Year	Base NG	High NG	Low NG	Coal
2012	$ 4.19	$ 9.19	$ 2.19	$ 2.12
2013	$ 4.33	$ 9.33	$ 2.33	$ 2.16
2014	$ 4.32	$ 9.32	$ 2.32	$ 2.18
2015	$ 4.55	$ 9.55	$ 2.55	$ 2.21
2016	$ 4.64	$ 9.64	$ 2.64	$ 2.25
2017	$ 4.77	$ 9.77	$ 2.77	$ 2.29
2018	$ 5.01	$ 10.01	$ 3.01	$ 2.33
2019	$ 5.23	$ 10.23	$ 3.23	$ 2.40
2020	$ 5.42	$ 10.42	$ 3.42	$ 2.45
2021	$ 5.74	$ 10.74	$ 3.74	$ 2.50
2022	$ 6.13	$ 11.13	$ 4.13	$ 2.56
2023	$ 6.44	$ 11.44	$ 4.44	$ 2.61
2024	$ 6.72	$ 11.72	$ 4.72	$ 2.68
2025	$ 6.97	$ 11.97	$ 4.97	$ 2.73
2026	$ 7.36	$ 12.36	$ 5.36	$ 2.79
2027	$ 7.70	$ 12.70	$ 5.70	$ 2.86
2028	$ 7.88	$ 12.88	$ 5.88	$ 2.92
2029	$ 8.00	$ 13.00	$ 6.00	$ 2.99
2030	$ 8.26	$ 13.26	$ 6.26	$ 3.06
2031	$ 8.70	$ 13.70	$ 6.70	$ 3.13
2032	$ 9.19	$ 14.19	$ 7.19	$ 3.20

Appendix 3: Unit Retirement Scenario

Unit Retirements in the BAU with Retirements Scenario

Name	Category	Area	Maximum Capacity (MW)	Commission Date	Retirement Date
Mountain Creek 6	ST Gas	NORTHCEN	122	2/1/1956	12/1/2006
Silas Ray 5	ST Gas	SOUTHERN	17	5/1/1951	12/1/2006
Mountain Creek 7	ST Gas	NORTHCEN	118	3/1/1958	12/1/2008
Stryker Creek 1	ST Gas	EAST	171	6/1/1958	12/1/2008
W A Parish 1	ST Gas	COAST	174	6/1/1958	12/1/2008
W A Parish 2	ST Gas	COAST	174	12/1/1958	12/1/2008
Graham 1	ST Gas	NORTHCEN	225	12/1/1960	12/1/2010
Pearsall 1	ST Gas	SOUTHERN	25	5/1/1961	12/1/2011
Pearsall 2	ST Gas	SOUTHERN	25	7/1/1961	12/1/2011
Pearsall 3	ST Gas	SOUTHERN	24	9/1/1961	12/1/2011
W A Parish 3	ST Gas	COAST	278	3/1/1961	12/1/2011
Handley 3	ST Gas	NORTHCEN	395	7/1/1963	12/1/2013
Sam Rayburn GT 1	CT Gas	COAST	13	1/3/1963	12/1/2013
Sam Rayburn GT 2	CT Gas	COAST	13	1/3/1963	12/1/2013
Sam Rayburn 3	ST Gas	COAST	26	7/1/1965	12/1/2015
Sim Gideon 1	ST Gas	SOUTHCEN	140	5/1/1965	12/1/2015
Stryker Creek 2	ST Gas	EAST	502	12/1/1965	12/1/2015
Trinidad 6	ST Gas	EAST	226	5/1/1965	12/1/2015
Sam Bertron 2	ST Gas	COAST	174	4/1/1956	1/1/2016
Powerlane Plant 1	ST Gas	NORTHCEN	20	8/1/1966	12/1/2016
V H Braunig 1	ST Gas	SOUTHCEN	220	3/1/1966	12/1/2016
Mountain Creek 8	ST Gas	NORTHCEN	568	7/1/1967	12/1/2017
Powerlane Plant 2	ST Gas	NORTHCEN	26.5	8/1/1967	12/1/2017
Ray Olinger 1	ST Gas	NORTHCEN	78	7/1/1967	12/1/2017
T H Wharton G 1	CT Gas	COAST	13	7/1/1967	12/1/2017
W A Parish T1	CT Gas	COAST	13	7/1/1967	12/1/2017
Sam Bertron 1	ST Gas	COAST	174	3/1/1958	1/1/2018
R W Miller 1	ST Gas	NORTHCEN	75	10/1/1968	12/1/2018
Sim Gideon 2	ST Gas	SOUTHCEN	140	3/1/1968	12/1/2018
V H Braunig 2	ST Gas	SOUTHCEN	230	4/1/1968	12/1/2018
W A Parish 4	ST Gas	COAST	552	6/1/1968	12/1/2018
Graham 2	ST Gas	NORTHCEN	390	6/1/1969	12/1/2019
Cedar Bayou 1	ST Gas	COAST	745	12/1/1970	12/1/2020
Lake Hubbard 1	ST Gas	NORTHCEN	392	6/1/1970	12/1/2020
Lake Hubbard 2	ST Gas	NORTHCEN	524	11/1/1970	12/1/2020
V H Braunig 3	ST Gas	SOUTHCEN	412	5/1/1970	12/1/2020
Decker Creek 1	ST Gas	SOUTHCEN	320	7/1/1971	12/1/2021
Ray Olinger 2	ST Gas	NORTHCEN	107	1/1/1971	12/1/2021
Cedar Bayou 2	ST Gas	COAST	749	3/1/1972	12/1/2022
O W Sommers 1	ST Gas	SOUTHCEN	410	4/1/1972	12/1/2022
R W Miller 2	ST Gas	NORTHCEN	120	7/1/1972	12/1/2022
Sim Gideon 3	ST Gas	SOUTHCEN	340	5/1/1972	12/1/2022
Atkins 7	CT Gas	EAST	20	5/1/1973	12/1/2023
B M Davis 1	ST Gas	SOUTHERN	335	5/1/1974	12/1/2024
O W Sommers 2	ST Gas	SOUTHCEN	400	1/1/1974	12/1/2024
T H Wharton 3	Combined Cycle (Existing)	COAST	332	8/1/1974	12/1/2024
T H Wharton 4	Combined Cycle (Existing)	COAST	332	8/1/1974	12/1/2024
Thomas C Ferguson 1	ST Gas	WEST	425	8/1/1974	12/1/2024
R W Miller 3	ST Gas	NORTHCEN	208	8/1/1975	12/1/2025
Ray Olinger 3	ST Gas	NORTHCEN	146	6/1/1975	12/1/2025
T H Wharton GT 51	CT Gas	COAST	58	11/1/1975	12/1/2025
T H Wharton GT 52	CT Gas	COAST	59	11/1/1975	12/1/2025
T H Wharton GT 53	CT Gas	COAST	58	11/1/1975	12/1/2025
T H Wharton GT 54	CT Gas	COAST	56	11/1/1975	12/1/2025
T H Wharton GT 55	CT Gas	COAST	58	11/1/1975	12/1/2025
T H Wharton GT 56	CT Gas	COAST	56	11/1/1975	12/1/2025
Greens Bayou 73	CT Gas	COAST	54	12/1/1976	12/1/2026
Greens Bayou 74	CT Gas	COAST	54	12/1/1976	12/1/2026

Unit Retirements (Cont'd).

Name	Category	Area	Maximum Capacity (MW)	Commission Date	Retirement Date
Greens Bayou 81	CT Gas	COAST	54	12/1/1976	12/1/2026
Greens Bayou 82	CT Gas	COAST	64	12/1/1976	12/1/2026
Greens Bayou 83	CT Gas	COAST	64	12/1/1976	12/1/2026
Greens Bayou 84	CT Gas	COAST	64	12/1/1976	12/1/2026
Handley 4	ST Gas	NORTHCEN	435	10/1/1976	12/1/2026
Handley 5	ST Gas	NORTHCEN	436	10/1/1977	12/1/2027
Dansby 1	ST Gas	EAST	110	9/1/1978	12/1/2028
Decker Creek 2	ST Gas	SOUTHCEN	428	1/1/1978	12/1/2028
Powerlane Plant 3	ST Gas	NORTHCEN	41.9	8/1/1978	12/1/2028

Appendix 4: Resource Expansion Analysis Results

BAU with All Technologies (BAU All Tech) (S1)

Description	Units	2014	2017	2020	2023	2026	2029	2032
CC Adds	MW	-	400	800	3,200	2,800	2,400	3,600
CT Adds	MW	-	700	3,100	800	600	1,300	900
Coal Adds	MW	-	-	-	-	-	-	-
Nuclear Adds	MW	-	-	-	-	-	-	-
CAES Adds	MW	-	-	-	-	-	-	-
Geothermal Adds	MW	-	-	-	-	-	-	-
Gravity Power Adds	MW	-	-	-	-	-	-	-
Solar Adds	MW	-	-	-	-	-	-	-
Wind Adds	MW	-	-	-	-	-	-	-
Annual Capacity Additions	MW	-	1,100	3,900	4,000	3,400	3,700	4,500
Cumulative Capacity Additions	MW	-	1,100	5,000	9,000	12,400	16,100	20,600
Retirements	MW	-	-	-	-	-	-	-
Residential Demand Response	MW	-	2,200	2,200	2,200	2,200	2,200	2,200
Industrial Demand Response	MW	500	500	500	500	500	500	500
Reserve Margin	%	8.32	2.80	2.79	3.04	2.89	2.39	1.33
Coincident Peak	MW	74,148	81,316	85,114	88,805	92,234	96,276	100,744
Average LMP	$/MWh	34.73	55.97	61.88	69.49	77.66	83.06	94.11
Natural Gas Price	$/mmbtu	4.32	4.77	5.42	6.44	7.36	8.00	9.19
Average Market Heat Rate	MMbtu/MWh	8.04	11.73	11.42	10.79	10.55	10.38	10.24
Natural Gas Generation	%	41.3	46.4	48.6	50.4	52.2	54.0	56.1
Coal Generation	%	36.0	33.2	32.0	30.7	29.6	28.4	27.3
Wind Generation	%	10.3	9.0	8.6	8.3	8.0	7.7	7.4
Scarcity Hours	HRS	-	17	17	16	20	21	21
Unserved Energy	GWhs	-	29.9	22.0	38.2	40.3	42.7	59.5
SO2	Tons	354,033	354,439	357,113	356,594	356,561	356,502	357,857
CO2	(k) Tons	229,961	247,892	251,225	264,772	272,112	280,358	290,395
NOx	Tons	129,480	138,280	139,958	143,322	143,939	145,780	148,097

BAU All Tech with Retirements (S2)

Description	Units	2016	2019	2022	2025	2028	2032
CC Adds	MW	800	3,600	1,300	800	2,000	-
CT Adds	MW	1,700	2,400	4,700	3,800	2,000	5,200
Coal Adds	MW	-	-	-	-	-	-
Nuclear Adds	MW	-	-	-	-	-	-
CAES Adds	MW	-	-	-	-	-	-
Geothermal Adds	MW	-	-	-	-	-	-
Gravity Power Adds	MW	-	-	-	-	-	-
Solar Adds	MW	-	-	2,000	3,000	2,000	3,000
Wind Adds	MW	-	-	-	-	-	1,500
Annual Capacity Additions	MW	2,500	6,000	8,000	7,600	6,000	9,700
Cumulative Capacity Additions	MW	2,500	8,500	16,500	24,100	30,100	39,800
Retirements	MW	3,068	2,249	4,109	2,543	1,796	-
Cumulative Retirements	MW	3,068	5,317	9,426	11,969	13,765	13,765
Residential Demand Response	MA	2,200	2,200	2,200	2,200	2,200	2,200
Industrial Demand Response	MW	500	500	500	500	500	500
Reserve Margin	%	0.8	0.8	(1.6)	(0.7)	(1.9)	(1.0)
Coincident Peak	MW	80,104	83,588	88,083	90,677	94,827	100,744
Average LMP	$/MWh	54.83	59.32	63.27	71.79	79.74	90.89
Natural Gas Price	$/mmbtu	4.64	5.23	6.13	6.97	7.88	9.19
Average Market Heat Rate	MMbtu/MWh	11.82	11.34	10.32	10.30	10.12	9.89
Natural Gas Generation	%	44.9	47.41	49.0	50.2	51.6	52.6
Coal Generation	%	33.9	31.9	31.0	30.2	29.4	28.1
Wind Generation	%	10.4	9.76	9.4	9.2	9.0	9.6
Solar Generation	%						
Scarcity Hours	HRS	15	22	16	18	20	24
Unserved Energy	GWhs	18	30	21	36	51	43
SO2	Tons	356,148	355,184	356,498	356,399	357,745	357,859
CO2	(k) Tons	224,284	252,516	259,336	264,152	271,086	279,479
NOx	Tons	135,712	136,282	137,352	138,184	140,030	142,519

BAU All Tech with Updated Wind Shapes (S3)

Description	Units	2016	2019	2022	2025	2028	2032
CC Adds	MW		1,600				2,000
CT Adds	MW	1,190		1,190	1,700	1,360	1,700
Coal Adds	MW						
Nuclear Adds	MW						
CAES Adds	MW						
Geothermal Adds	MW						
Gravity Power Adds	MW						
Solar Adds	MW		1,500	3,000	2,000	1,000	2,500
Wind Adds	MW	300	1,886	4,782	2,291	3,818	3,778
Annual Capacity Additions	MW	1,490	4,986	8,972	5,991	6,178	9,978
Cumulative Capacity Additions	MW	1,490	6,476	15,448	21,439	27,617	37,595
Retirements	MW	-	-	-	-	-	-
Residential Demand Response	MW	-	-	-	-	-	-
Industrial Demand Response	MW	-	-	-	-	-	-
Reserve Margin	%	0.00	(0.80)	(2.37)	(1.95)	(4.00)	(4.35)
Coincident Peak	MW	80,104	83,588	88,083	90,677	94,827	100,744
Average LMP	$/MWh	50.52	57.87	63.02	70.03	77.12	87.99
Natural Gas Price	$/mmbtu	4.64	5.23	6.13	6.97	7.88	9.18
Average Market Heat Rate	MMbtu/MWh	10.89	11.07	10.28	10.05	9.79	9.58
Natural Gas Generation	%	44.0	44.1	40.9	39.9	38.7	38.5
Coal Generation	%	35.2	33.3	32.0	30.9	29.8	28.2
Wind Generation	%	9.5	10.8	14.5	16.2	18.7	20.3
Solar Generation	%	-	0.7	2.0	2.8	3.1	3.9
Scarcity Hours	HRS	15	18	21	28	30	37
Unserved Energy	GWhs	20.4	29.4	31.6	48.3	57.1	87.9
SO2	Tons	356,096	355,301	356,347	356,442	357,140	357,409
CO2	(k) Tons	246,956	250,747	248,318	249,700	251,057	255,536
NOx	Tons	276,450	276,541	273,803	273,774	274,846	273,963

Extended Drought (S5a)

Description	Units	2016	2019	2022	2025	2028	2032
CC Adds	MW	-	2,400	-	-	-	1,200
CT Adds	MW	9,010	510	-	170	510	2,890
Coal Adds	MW	-	-	-	-	-	-
Nuclear Adds	MW	-	-	-	-	-	-
CAES Adds	MW	-	-	-	-	-	-
Geothermal Adds	MW	300	700	1,500	1,100	-	-
Gravity Power Adds	MW	-	-	-	-	-	-
Solar Adds	MW	-	2,500	2,000	2,000	2,000	2,500
Wind Adds	MW	523	1,211	3,680	2,738	4,533	346
Annual Capacity Additions	MW	9,833	7,321	7,180	6,008	7,043	6,936
Cumulative Capacity Additions	MW	9,833	17,154	24,334	30,342	37,385	44,321
Retirements	MW	-	-	-	-	-	-
Residential Demand Response	MW	-	-	-		-	-
Industrial Demand Response	MW	-	-	-	-	500	500
Reserve Margin	%	2.89	2.74	1.73	0.19	(2.22)	(1.75)
Coincident Peak	MW	86,113	91,068	94,728	98,666	103,502	108,981
Average LMP	$/MWh	52.78	59.19	63.42	69.38	77.82	88.05
Natural Gas Price	$/mmbtu	4.64	5.23	6.13	6.97	7.88	9.18
Average Market Heat Rate	MMbtu/MWh	11.38	11.32	10.35	9.95	9.88	9.59
Natural Gas Generation	%	45.1	44.6	42.4	38.2	35.9	38.2
Coal Generation	%	33.1	31.5	31.4	29.1	28.2	26.7
Wind Generation	%	10.8	12.4	17.3	20.4	23.3	22.2
Solar Generation	%	-	1.1	1.9	2.6	3.3	4.0
Scarcity Hours	HRS	22.0	24.0	25.0	15.0	30.0	27.0
Unserved Energy	GWhs	25.5	27.5	39.4	9.5	38.7	38.0
SO2	Tons	356,652	355,660	355,081	356,699	353,838	359,705
CO2	(k) Tons	254,938	250,014	245,345	243,602	243,465	251,304
NOx	Tons	279,508	275,042	270,869	269,274	269,997	274,402

BAU All Tech with High Natural Gas Price (S7)

Description	Units	2016	2019	2022	2025	2028	2032
CC Adds	MW	-	-	-	-	-	-
CT Adds	MW	-	-	-	-	680	2,210
Coal Adds	MW	-	-	-	-	-	-
Nuclear Adds	MW	-	-	-	-	-	-
CAES Adds	MW	-	-	-	-	-	-
Geothermal Adds	MW	1,500	1,500	600	-	-	-
Gravity Power Adds	MW	-	-	-	-	-	-
Solar Adds	MW	-	-	15,500	500	500	1,500
Wind Adds	MW	38,901	8,768	5,260	8,167	3,523	5,845
Annual Capacity Additions	MW	40,401	10,268	21,360	8,667	4,703	9,555
Cumulative Capacity Additions	MW	40,401	50,669	72,029	80,696	85,399	94,954
Retirements	MW	-	6,938	14,303	-	-	-
Residential Demand Response	MW	-	-	-		-	-
Industrial Demand Response	MW	-	-	500	500	500	500
Reserve Margin	%	5.07	(5.10)	(16.05)	(16.95)	(18.91)	(19.86)
Coincident Peak	MW	80,104	83,588	88,083	90,677	94,827	100,744
Average LMP	$/MWh	69.48	72.19	90.05	86.22	95.96	101.85
Natural Gas Price	$/mmbtu	9.55	10.01	10.74	11.72	12.70	13.70
Average Market Heat Rate	MMbtu/MWh	7.28	7.21	8.38	7.36	7.56	7.43
Natural Gas Generation	%	19.7	18.3	24.0	22.2	22.7	23.2
Coal Generation	%	23.2	19.7	6.3	5.8	5.6	5.3
Wind Generation	%	45.1	50.8	50.2	55.0	55.4	55.6
Solar Generation	%	-	-	6.8	6.7	6.7	6.9
Scarcity Hours	HRS	-	4.0	26.0	19.0	15.0	14.0
Unserved Energy	GWhs	-	2.0	46.4	35.4	22.1	33.2
SO2	Tons	217,810	192,720	23,108	23,003	21,436	21,696
CO2	(k) Tons	148,543	135,939	86,273	83,035	86,014	90,442
NOx	Tons	171,238	156,730	83,051	80,534	83,277	86,848

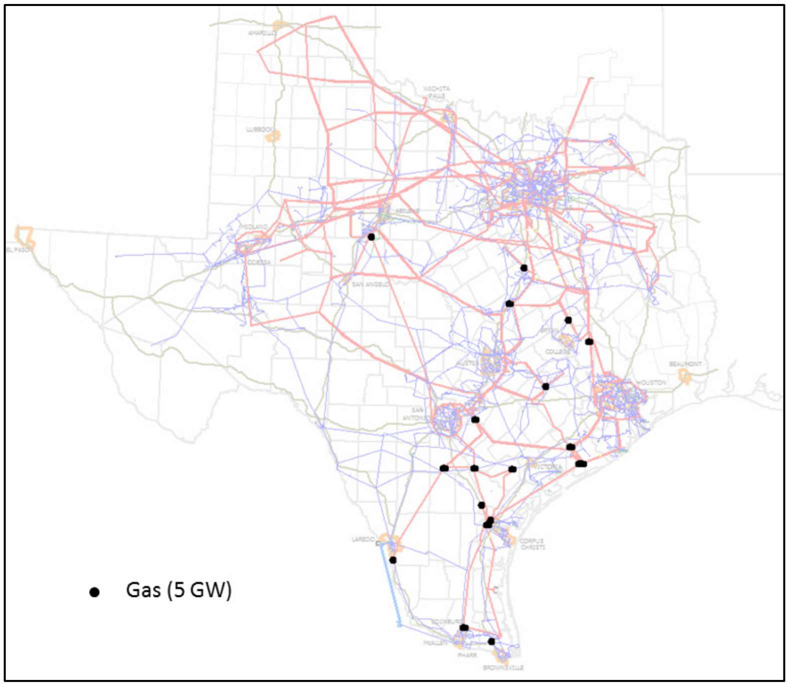
Environmental (S8)

Description	Units	2016	2019	2022	2025	2028	2032
CC Adds	MW	-	-	-	-	-	-
CT Adds	MW	-	-	-	-	-	400
Coal Adds	MW	-	-	-	-	-	-
Nuclear Adds	MW	-	-	-	-	-	-
CAES Adds	MW	-	-	-	-	-	-
Geothermal Adds	MW	-	1,500	1,500	600	-	-
Gravity Power Adds	MW	-	-	-	-	-	-
Solar Adds	MW	-	-	6,000	2,000	2,000	3,000
Wind Adds	MW	17,621	820	2,337	3,907	5,234	6,056
Annual Capacity Additions	MW	17,621	2,320	9,837	6,507	7,234	9,456
Cumulative Capacity Additions	MW	17,621	19,941	29,778	36,285	43,519	52,975
Retirements	MW	-	718	4,174	-	-	-
Cumulative Retirements	MW	-	718	4,892	4,892	4,892	4,892
Residential Demand Response	MW	-	-	-	-	-	-
Industrial Demand Response	MW	-	-	-	-	-	-
Reserve Margin	%	3.7	0.3	(4.5)	(4.1)	(7.8)	(11.0)
Coincident Peak	MW	80,104	83,588	88,083	90,677	94,827	100,744
Average LMP	$/MWh	58.47	66.52	75.14	78.59	85.41	95.24
Natural Gas Price	$/mmbtu	9.55	10.01	10.74	11.72	12.70	13.70
Average Market Heat Rate	MMbtu/MWh	6.12	6.65	7.00	6.71	6.73	6.95
Natural Gas Generation	%	27.3	27.81	24.8	22.9	22.5	22.5
Coal Generation	%	33.6	32.14	30.6	29.2	27.9	25.9
Wind Generation	%	28.3	27.55	28.0	29.6	31.7	33.5
Solar Generation	%	0.0	0.01	2.6	3.4	4.0	5.0
Scarcity Hours	HRS	-	2	10	13	18	30
Unserved Energy	GWhs	-	2	14	19	33	38
SO2	Tons	347,741	348,521	346,179	343,510	340,324	335,050
CO2	(k) Tons	209,175	213,191	207,738	205,647	204,504	205,314
NOx	Tons	242,368	246,138	240,107	237,557	236,897	236,855

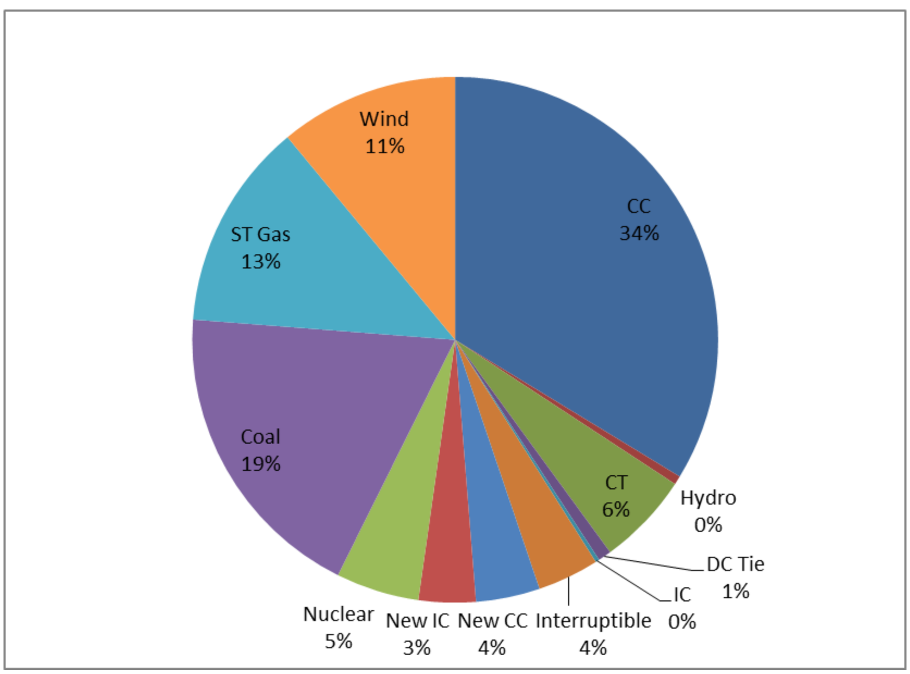
Appendix 5: Transmission System Needs Analysis Results

Scenario: Business as Usual with All Technologies - 2022

New Resources:



Annual Generation Energy Mix:



Demand Response:

City	Capacity (MW)	
	Industrial	Residential/Commercial
Austin	60	275
Dallas	160	733
Houston	200	734
San Antonio	80	458

Peak load:

Hour: 8/4/2022 hour 16

System load (coincident peak): 89214 MW

Thermal & Hydraulic output: 86298 MW

Peak renewable:

Hour: 4/22/2022 hour 8

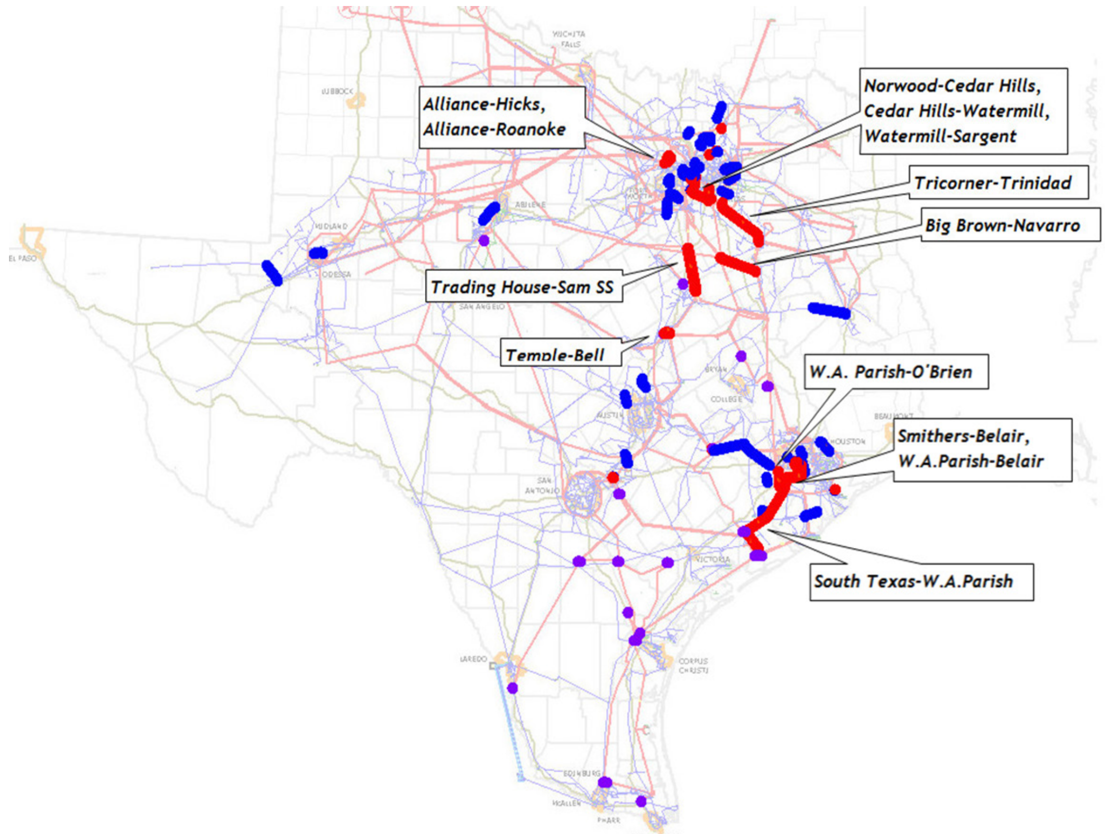
System load: 49447.8 MW

Renewable output: 9488.8 MW

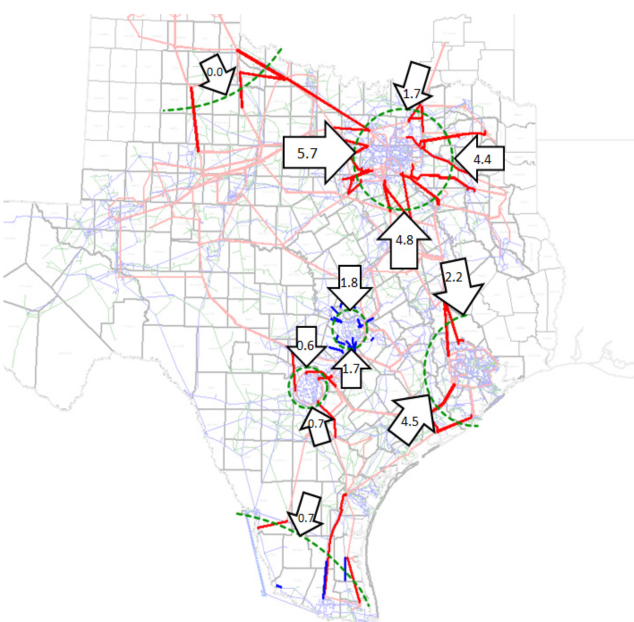
Import limits determined by AC voltage stability analysis:

Load Center	Interface Limits (MW)	Potential year of voltage instability	Critical Contingencies (Under G-1)
Dallas	18890	2022	Trinidad-Tricorner-Watermill
Houston	8827	2022	Roans Prairie-Kuykendahl & Singleton-Tomball
Austin / San Antonio	3033	2027	Hill Country-Marion & Skyline-Marion
Valley	Not tested since incremental future generation in the region will only improve the system stability. Instead, previous interface limit was imposed at 2512 MW		

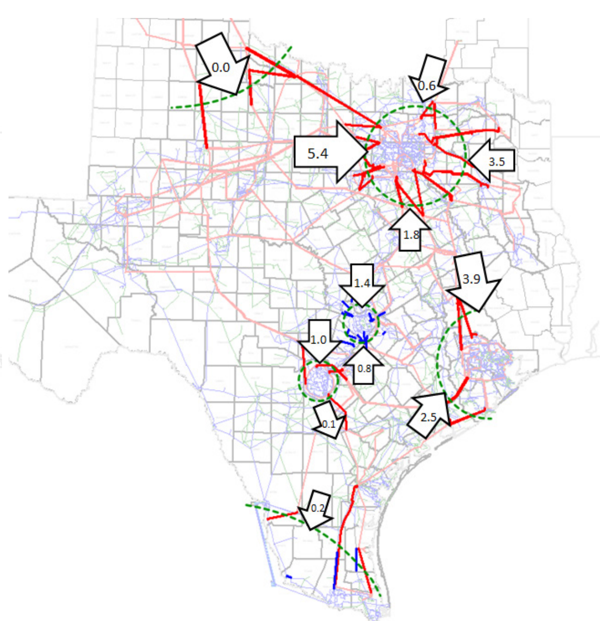
Base Case Overloads:



System flows at peak load hour:

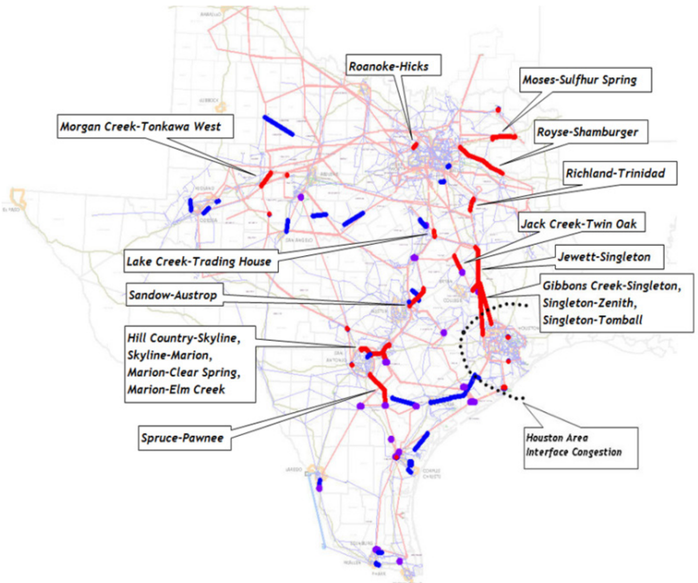


System flows at peak wind hour:



*All numbers are in GW

Congestion map:

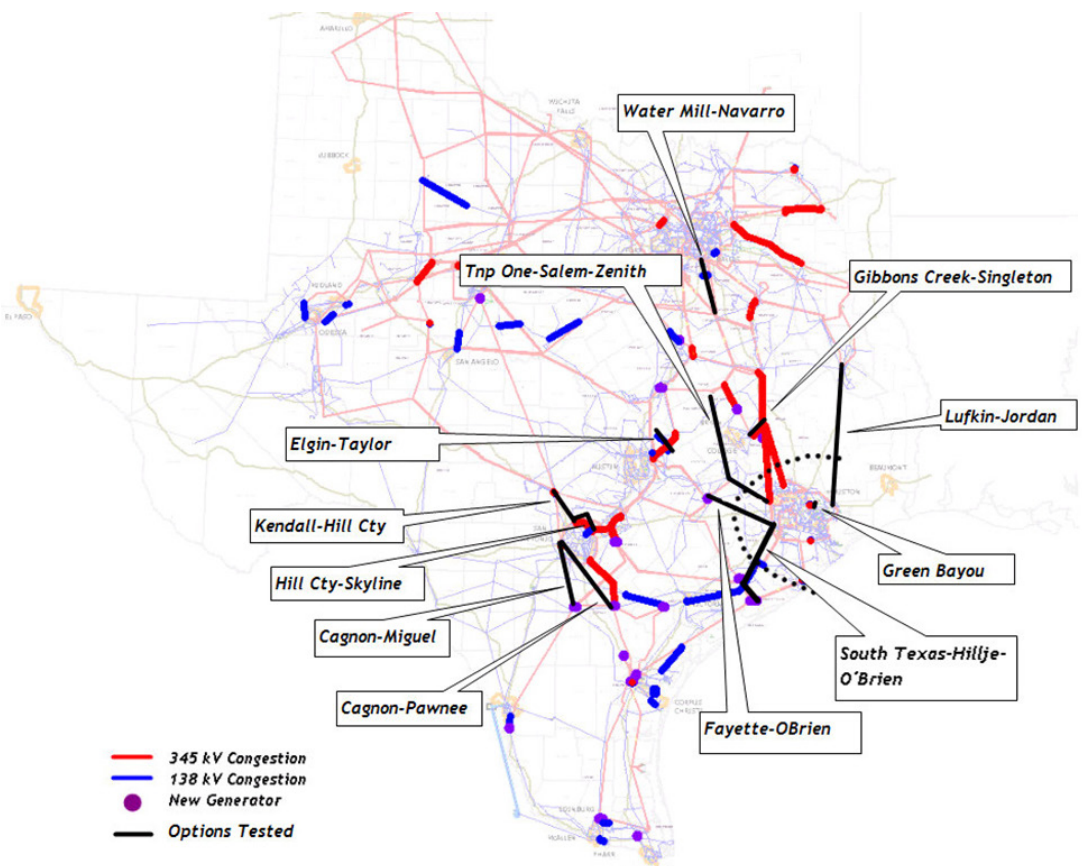


Most congested Elements:

FROM	TO	Name (FR)	Name (TO)	Congestion Cost ($M)
5211	5371	HILL COUNTRY	SKYLINE	99
40700	40716	GREENS BAYOU	GREENS BAYOU	41
967	44645	GIBBONS CREEK	SINGLETON	26
3650	3658	ELGIN SS	TAYLOR	21
7046	7150	KENDALL	KENDALL	19

* Grey items are transformers

Economic Projects Tested



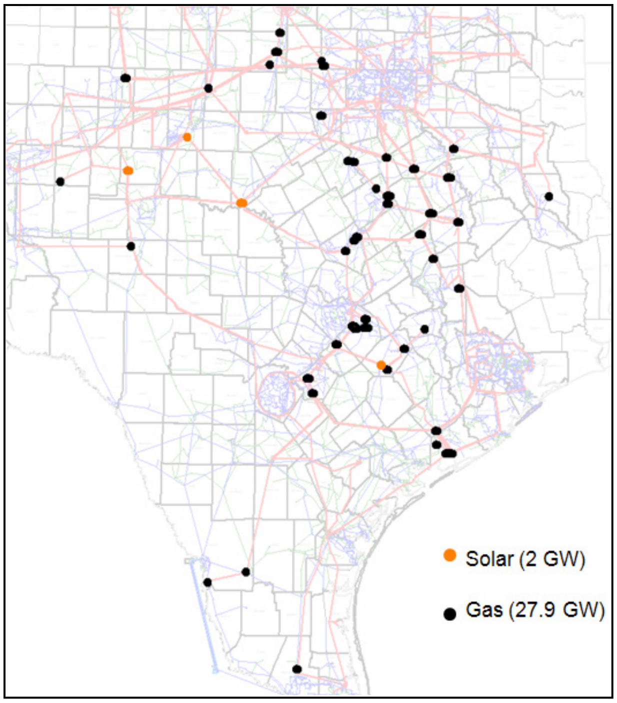
Economic Results

Tested Project	Capital cost	Reliability benefit	Adjusted Capital Cost for Reliability Benefit	Production Cost Savings	1/6 of Adjusted Capital Cost	Meet ERCOT Economic Criteria?
Watermill-Navarro	150.2	-67.0	217.2	0.2	36.2	No
Fayette-O Brien	241.7	-108.8	132.9	0.6	22.2	No
Lufkin-Jordan	430.2	36.7	466.9	4.1	77.8	No
TNP One-Salem-Zenith	444.6	-105.3	339.3	6.2	56.6	No
Upgrade Gibbons Creek-Singleton	23.8	n/a	n/a	0.5	4.0	No
Upgrade Green Bayou 345/138 kV	11.9	n/a	n/a	2.8	2.0	Yes
Upgrade S. Texas-Hillje, and Hillje-O'Brien	254	-54.1	199.9	4.1	33.3	No
Cagnon-Miguel	193.3	87.4	280.7	3	46.8	No
Cagnon-Miguel & Cagnon 345/138 kV	217.1	n/a	n/a	4.5	36.2	No
Cagnon-Pawnee	241.7	137.3	379.0	3.7	63.2	No
Cagnon-Pawnee & Cagnon 345/138 kV	265.4	n/a	n/a	4.9	44.2	No
Kendall-Hill Country	145	n/a	n/a	-8.2	24.2	No
Upgrade Elgin-Taylor	15.3	n/a	n/a	1	2.6	No
Upgrade Hill Country-Sky	30.3	n/a	n/a	1.2	5.1	No

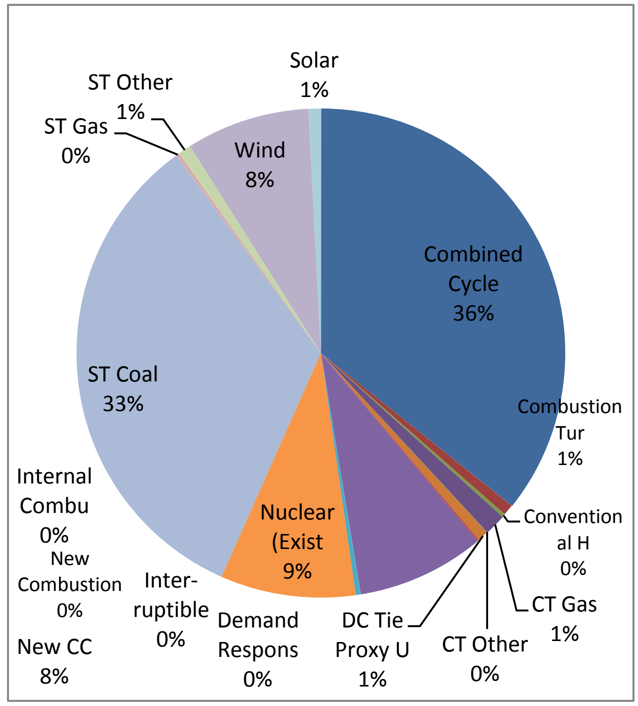
*All numbers are in millions in 2022.

Scenario: Business as Usual with Retirements - 2022

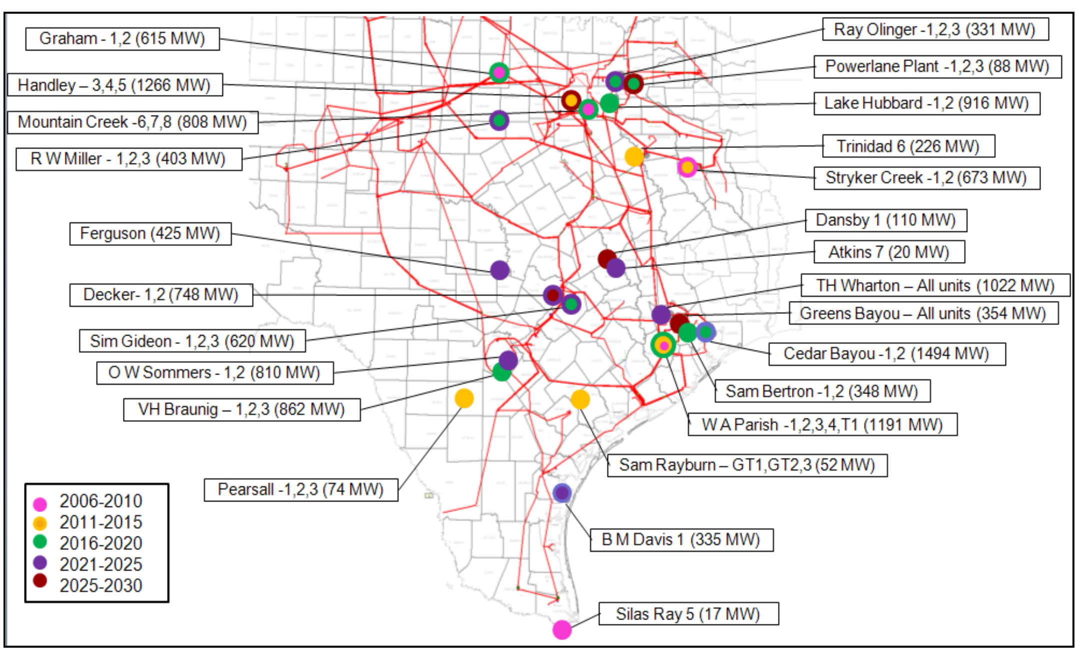
New Resources



Annual Generation Energy Mix:



Retirement Resources (Natural gas units over 50 years old)



Peak load:

Hour: 8/4/2022 hour 16

System load (coincident peak): 89214 MW

Thermal & Hydraulic output: 85159 MW

Peak renewable:

Hour: 3/23/2022 hour 4

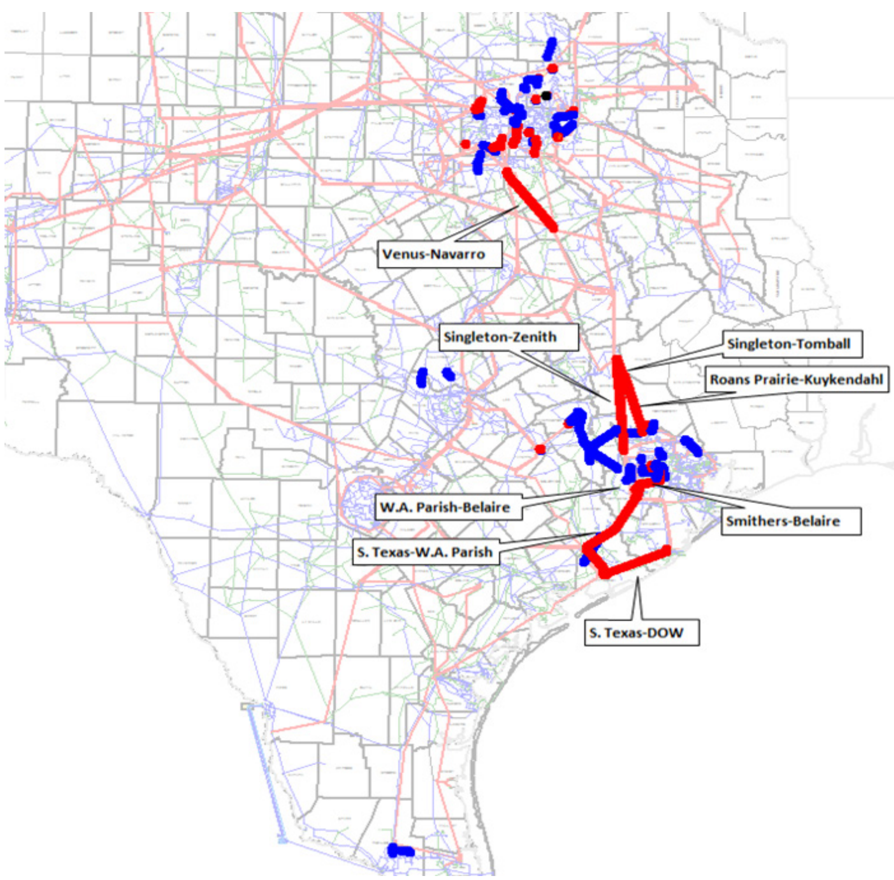
System load: 38126 MW

Renewable output: 9281 MW

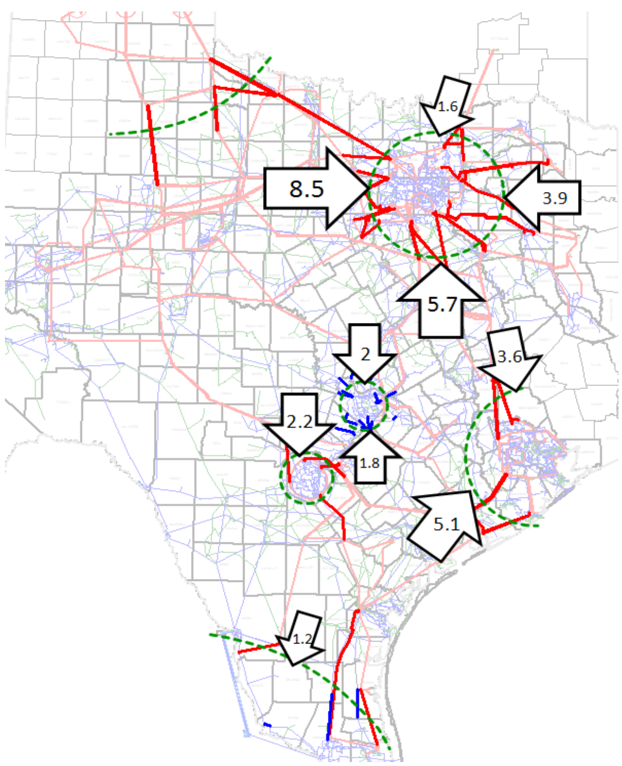
Import limits determined by AC voltage stability analysis:

Load Center	Interface Limits (MW)	Potential year of voltage instability	Critical Contingencies
Dallas	19949	2022	Tricorner/Watermill
Houston	8735	2019	Singleton-Zenith
San Antonio	4048	2028	Hill Country - Marion & Skyline - Marion
Austin	3839	2028	Elm Creek-South Texas
Valley	Not tested since incremental future generation in the region will only improve the system stability. Instead, previous interface limit was imposed at 2512 MW		

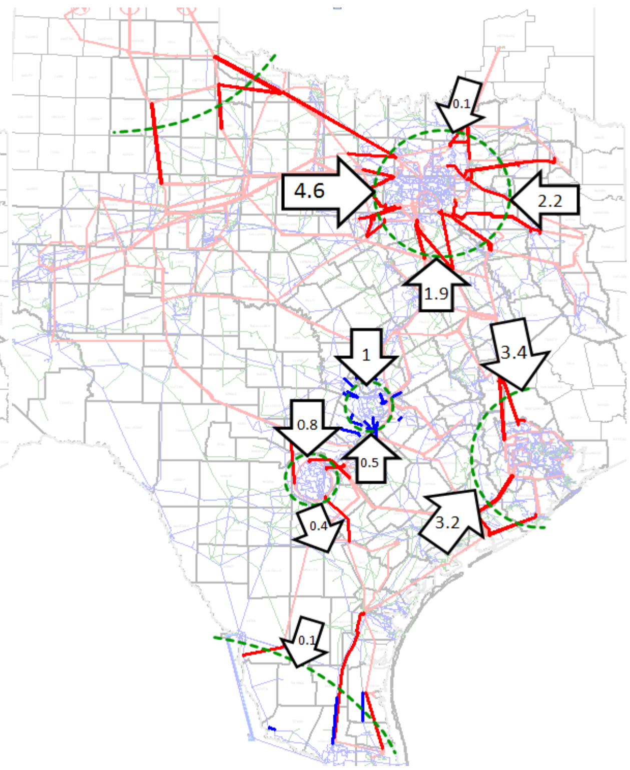
Base Case Overloads:



System flows at peak load hour:

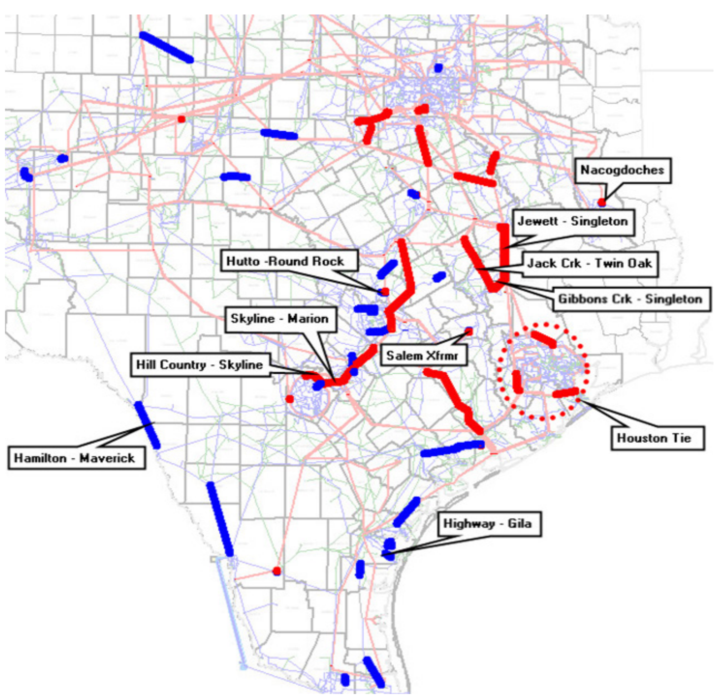


System flows at peak wind hour:



*All numbers are in GW

Congestion map:

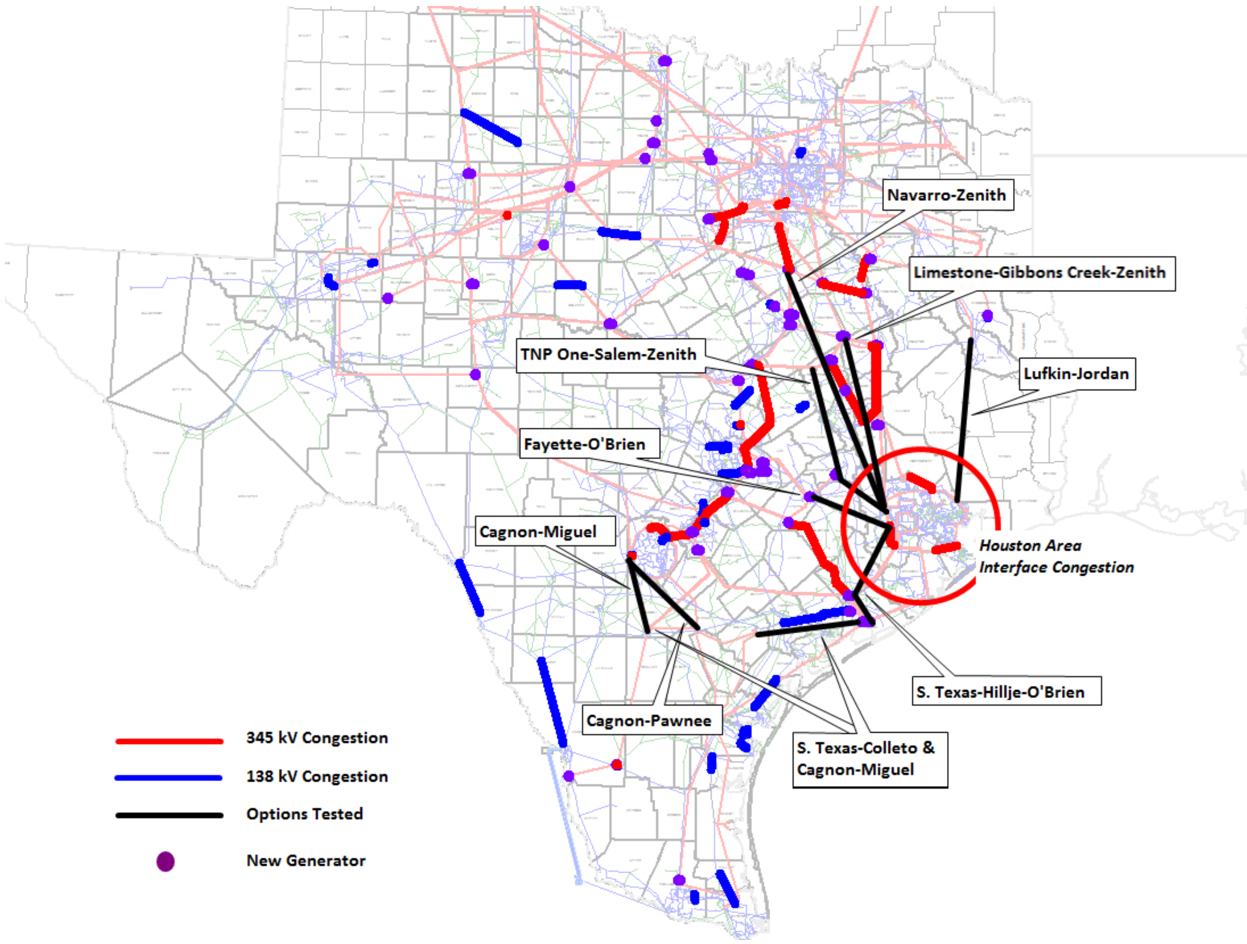


Most congested Elements:

FROM	TO	Name(FR)	Name(To)	Congestion cost($M)
Houston Tie				457.91
5211	5371	HILL COUNTRY	SKYLINE	74.01
8255	8692	HAMILTON RD	MAVERICK	59.22
5371	7044	SKYLINE	MARION	43.82
967	44645	GIBBONS CRK	SINGLETON	27.66
3666	3670	HUTTO SW	ROUND ROCK	27.44
7058	7289	SALEM	SALEM	21.04
3391	44645	JEWETT	SINGLETON	19.42
975	3400	JACKCREEK	TWIN OAK	16.37

*Grey items are transformers

Economic Projects Tested (All Black lines 345kV Double Circuit except for Hays Kendall)

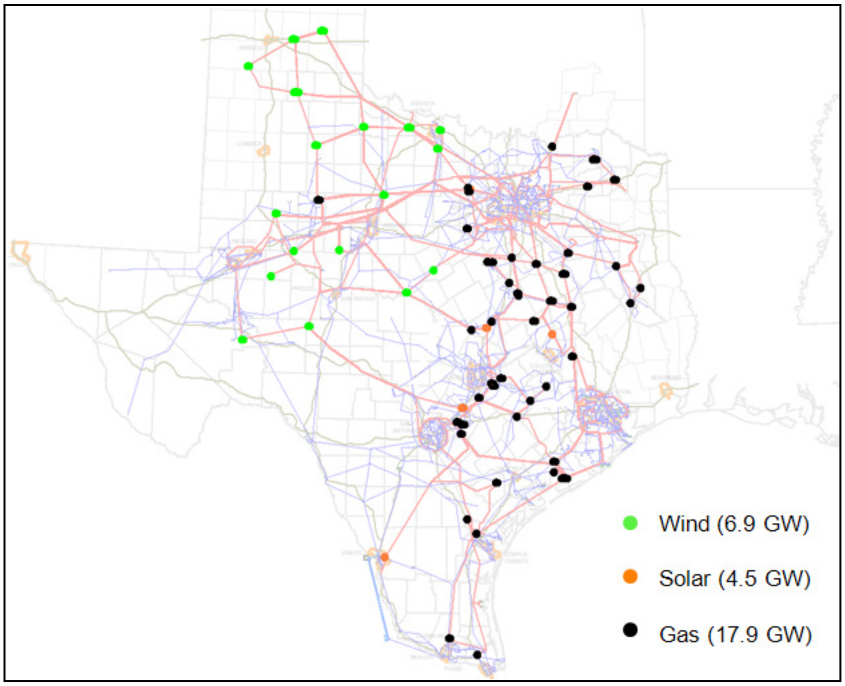


Economic Results

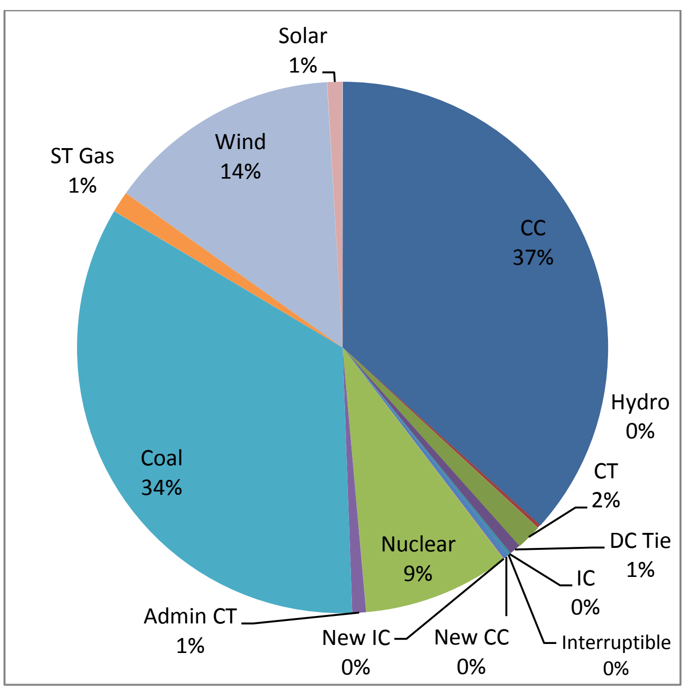
Tested Project	Capital cost	Reliability benefit	Adjusted Capital Cost for Reliability Benefit	Production Cost Savings	1/6 of Adjusted Capital Cost	Meet ERCOT Economic Criteria ?
Fayette-O Brien	241.7	345.2	-103.5	30.8	-17.3	YES
Lufkin-Jordan	439.1	138.5	300.6	28	50.1	NO
TNP One-Salem-Zenith	444.6	520.4	-75.7	37.5	-12.6	YES
Hillje-Obrien and South Texas-Hillje upgrade	265.3	262.3	3	28.3	0.5	YES
Navarro-Zenith	597.8	101.1	496.7	29.7	82.8	NO
Limestone - Gibbons Creek -Zenith	327.2	361.6	-34.4	40.9	-5.7	YES

Scenario: Business as Usual with Updated Wind Shapes - 2022

New Resources



Annual Generation Energy Mix:



Peak load:

Hour: 8/4/2022 hour 16

System load (coincident peak): 89214 MW

Thermal & Hydraulic output: 84231 MW

Peak renewable:

Hour: 3/26/2022 hour 22

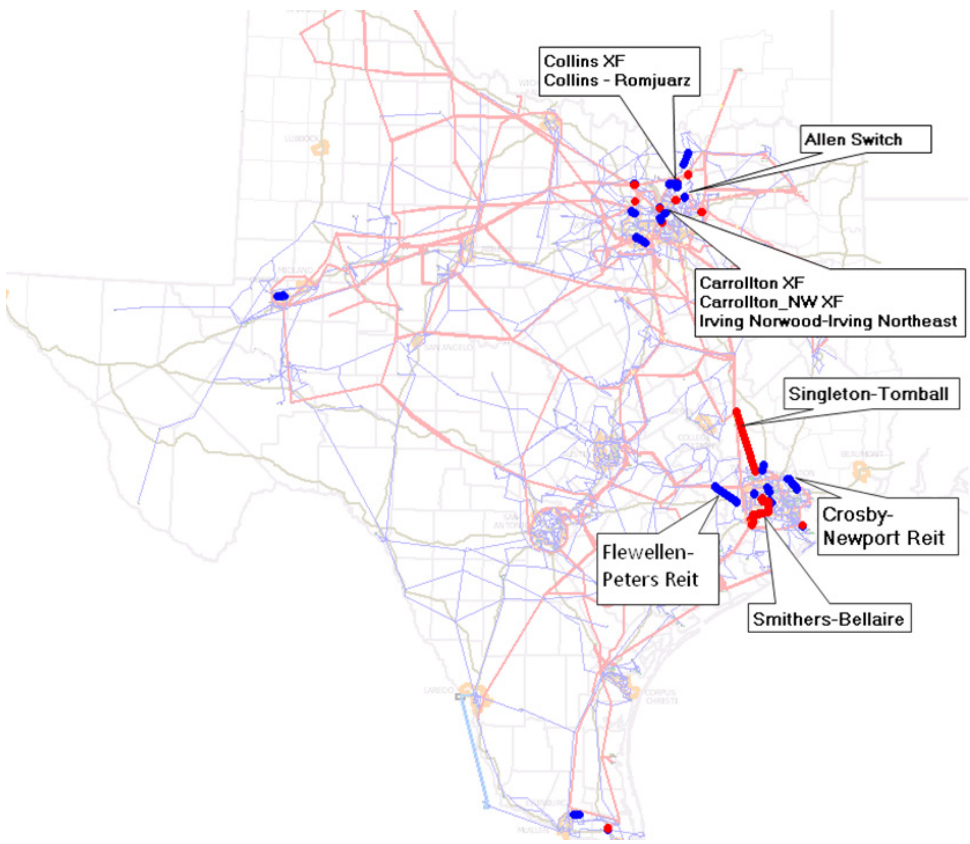
System load: 40382 MW

Renewable output: 14525 MW

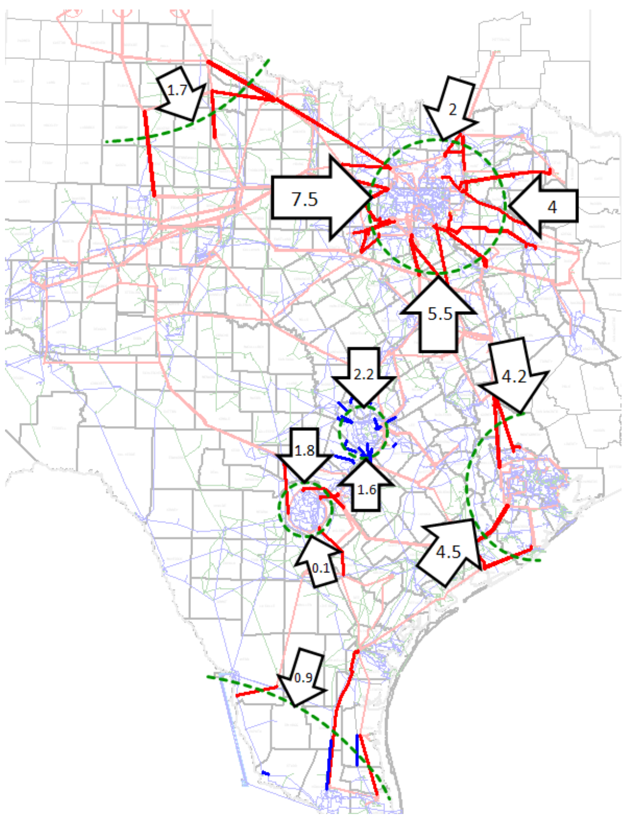
Import limits determined by AC voltage stability analysis:

Load Center	Interface Limits (MW)	Potential year of voltage instability	Critical Contingencies (Under G-1)
Dallas	20318	2026	Parker-Hicks sw/Eagle mountain
Houston	9440	2028	Roans Prairie-Kuykendhal & Singleton-Tomball
San Antonio	3796	2030	Hill Country-Marion
Austin	4572	Beyond 2032	Elm Creek-South Texas
Valley	Not tested since incremental future generation in the region will only improve the system stability. Instead, previous interface limit was imposed at 2512 MW		

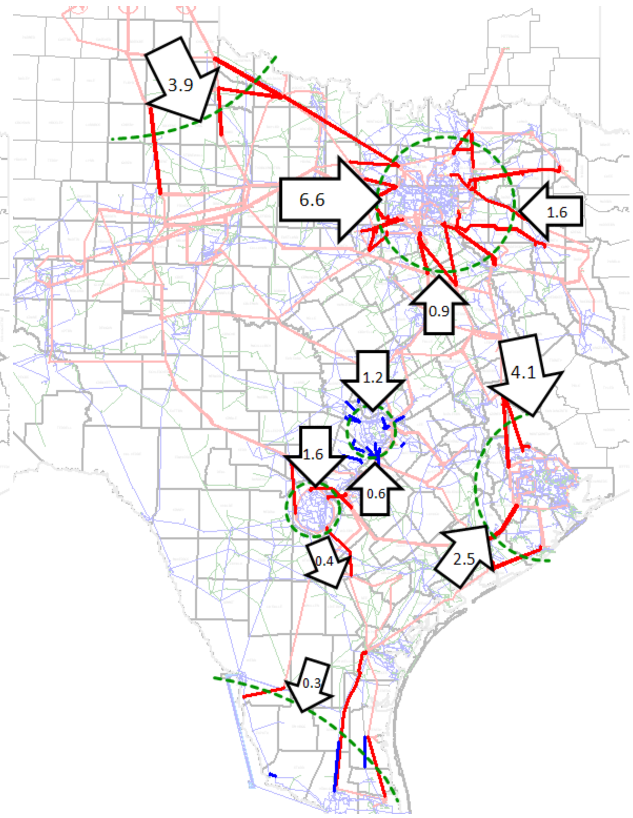
Base Case Overloads:



System flows at peak load hour:

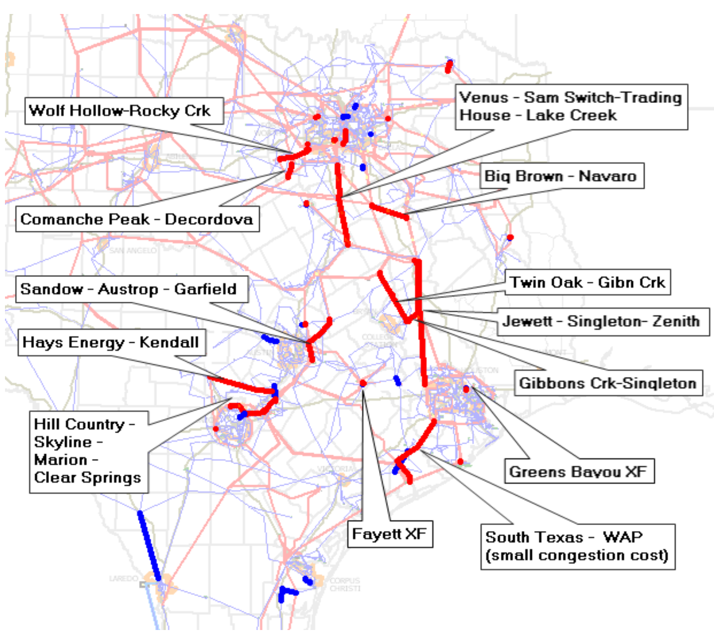


System flows at peak wind hour:



*All numbers are in GW

Congestion map:

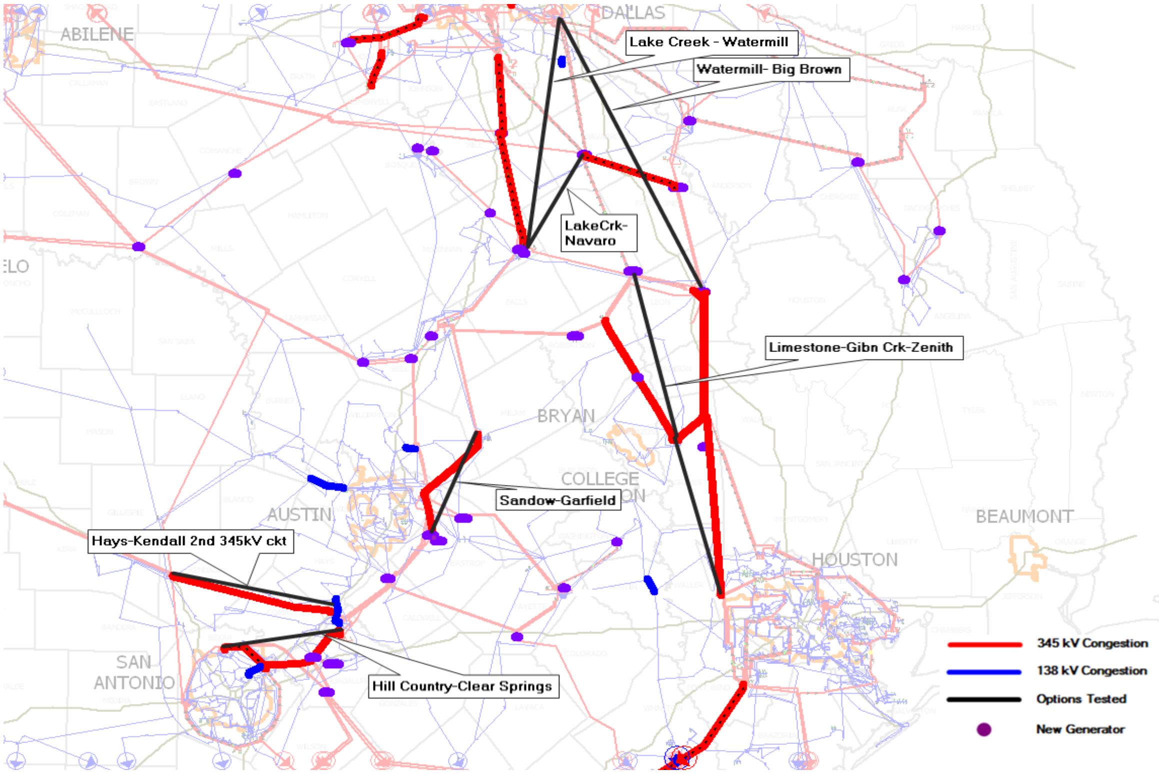


Most congested Elements:

FROM	TO	Name (FR)	Name (TO)	Congestion Cost($M)
40700	40716	GREENS BAYOU	GREENS BAYOU	$64.98
44645	44900	SINGLETON	ZENITH	$64.79
8255	8692	HAMILTON RD	MAVERICK	$63.69
7057	7286	FAYETTEVILLE	FAYETTEVILLE	$52.34
1876	1880	WOLF HOLLOW	ROCKY CREEK	$39.48
967	44645	GIBBONS CRK	SINGLETON	$38.19
44645	44900	SINGLETON	ZENITH	$33.58
1876	1880	WOLF HOLLOW	ROCKY CREEK	$21.74
7043	7046	HAYS ENERGY	KENDALL	$18.08

*Grey items are transformers

Economic Projects Tested (All Black lines 345kV Double Circuit except for Hays-Kendall)

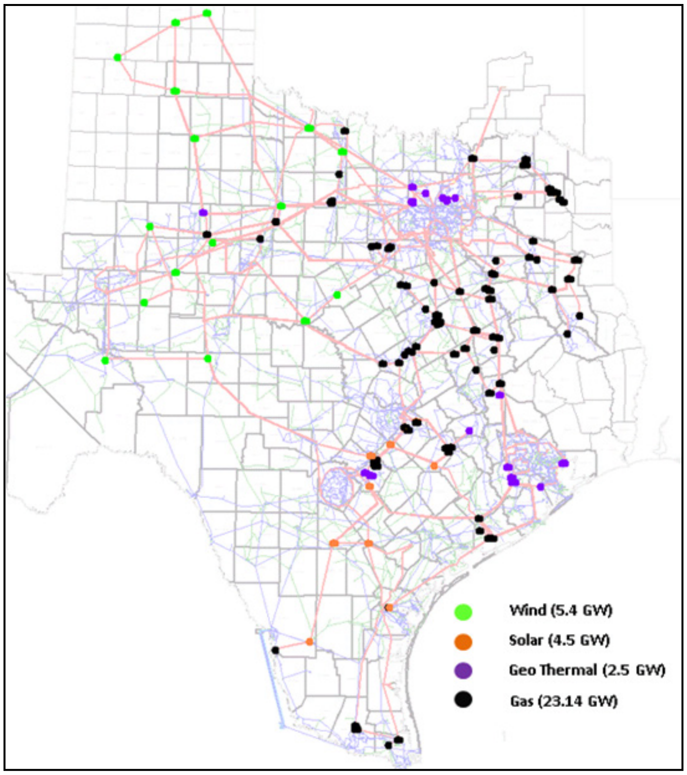


Economic Results

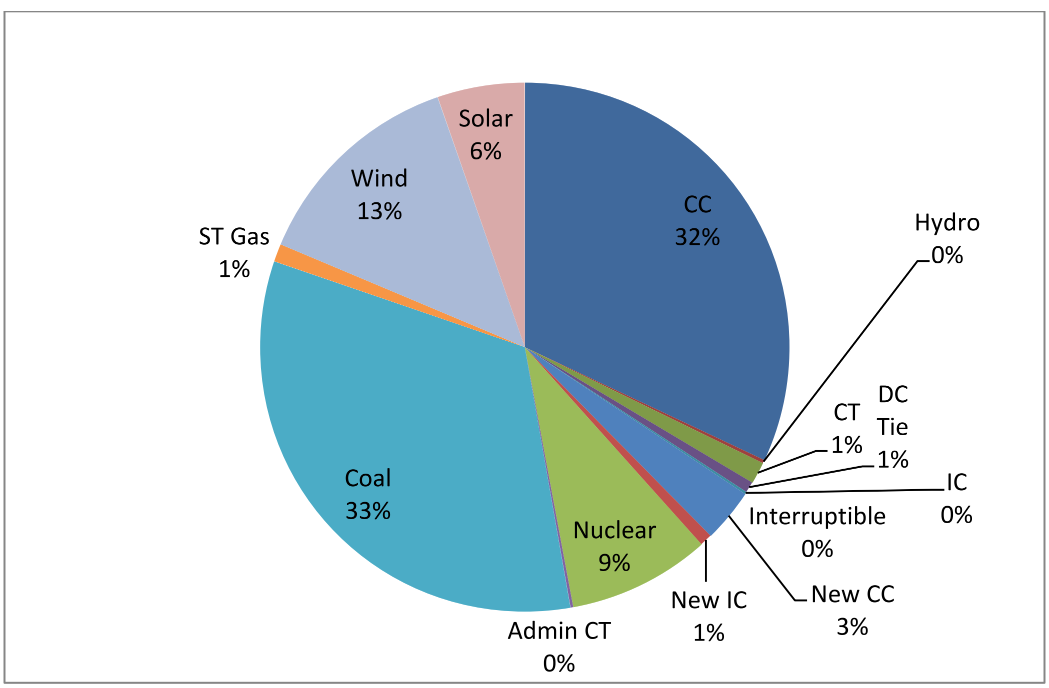
Tested Project	Capital cost	Reliability benefit	Adjusted Capital Cost for Reliability Benefit	Production Cost Savings	1/6 of Adjusted Capital Cost	Meet ERCOT Economic Criteria ?
Limest-Gibn Crk- Zenith	327.2	120.6	206.6	36.6	34.4	Yes
Watermill-Big Brown	208.2	23.1	185.1	0.1	30.9	No
Lake Creek - Navaro	104.1	42.1	62.0	1.7	10.3	No
LakeCrk -wtm	297.4	19.0	278.4	0.4	46.4	No
Clear Spring - Hill County	104.1	0.0	104.1	4.1	17.4	No
Hays - Kendall 2nd 345kV ckt	41.8	0.0	41.8	3.2	7.0	No
Sandow - Garfield	133.8	0.0	133.8	4.0	22.3	No

Scenario: Extended Drought - 2022

New Resources



Annual Generation Energy Mix:



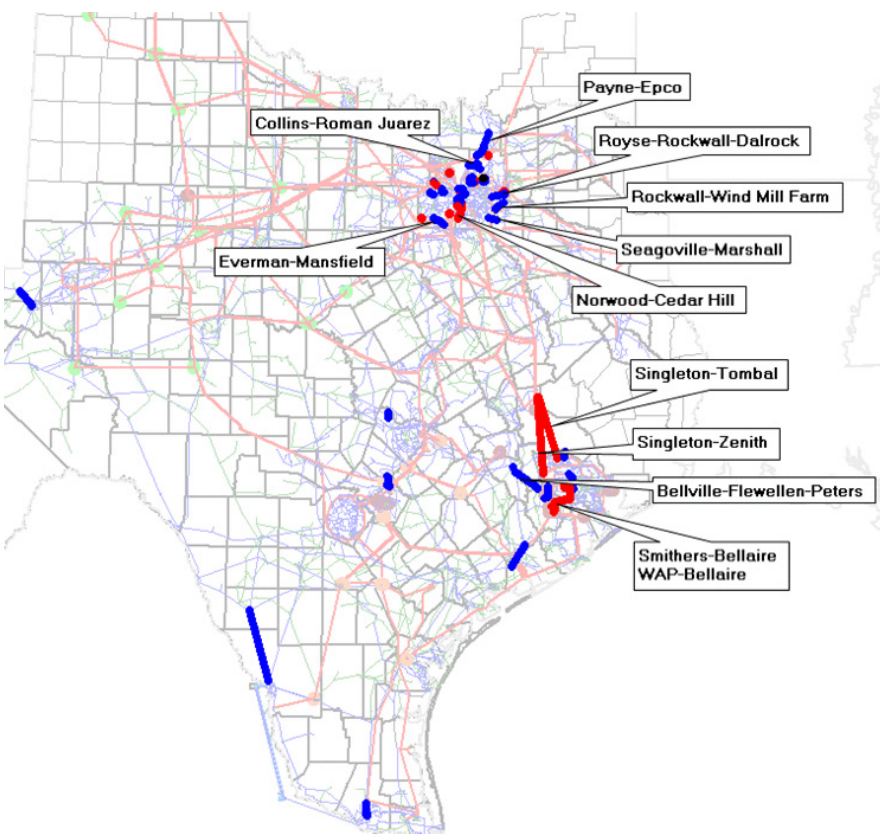
Peak load:
Hour: 8/16/2022 hour 16
System load (coincident peak): 92613 MW
Thermal & Hydraulic output: 82442 MW

Peak renewable:
Hour: 3/15/2022 hour 23
System load: 39645 MW
Renewable output: 15749 MW

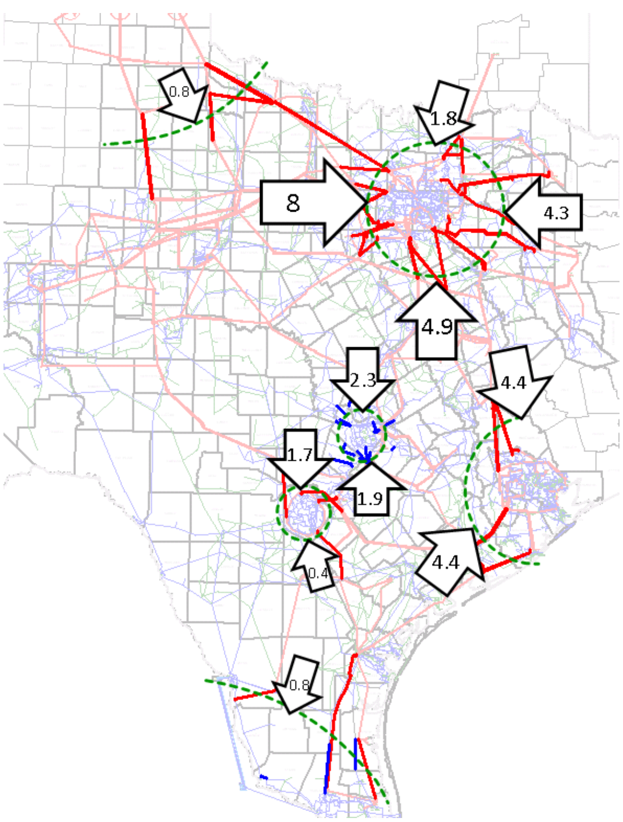
Import limits determined by AC voltage stability analysis:

Load Center	Interface Limits (MW)	Potential year of voltage instability	Critical Contingencies (Under G-1)
Dallas	18890	202	Trinidad-Tricorner/Watermill
Houston	8827	2024	Roan-Kuykendahl & Singleton-Tomball, Fayette-Zenith, Hillje-W.A. Parish, or South Texas-Dow
San Antonio	3033	2028	Hill Country - Marion & Skyline - Marion
Austin	3839	2028	Elm Creek-South Texas
Valley	Not tested since incremental future generation in the region will only improve the system stability. Instead, previous interface limit was imposed at 2512 MW		

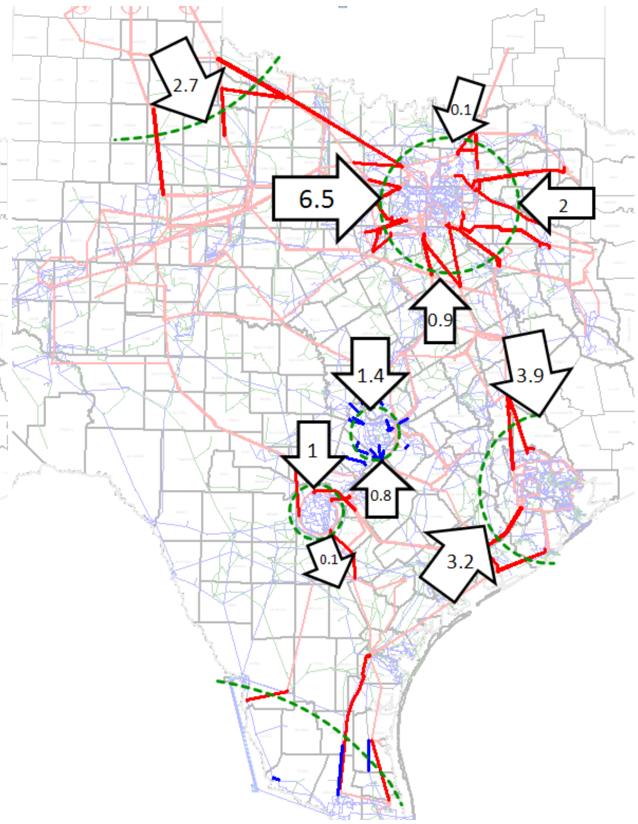
Base Case Overloads:



System flows at peak load hour:

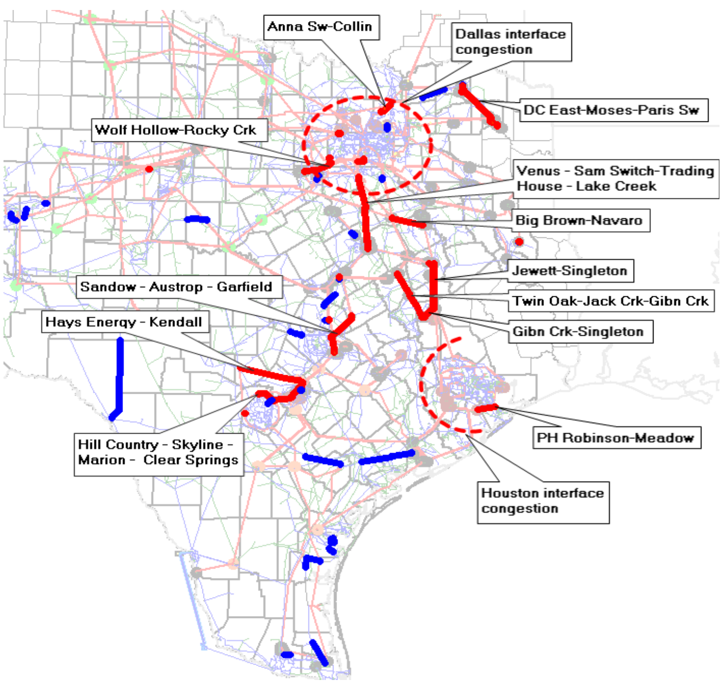


System flows at peak wind hour:



*All numbers are in GW

Congestion map:

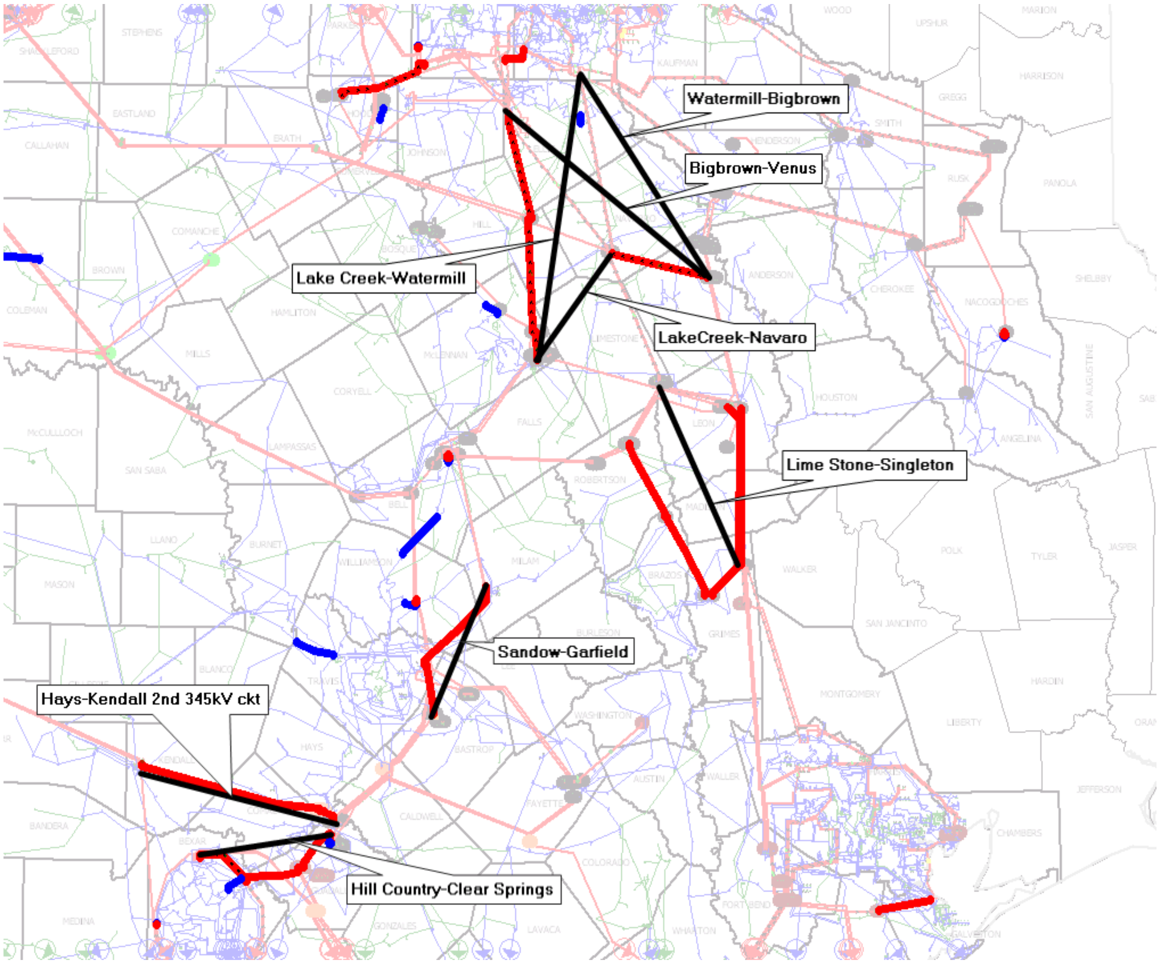


Most congested Elements:

FROM	TO	Name (FR)	Name (TO)	Congestion Cost($M)
8257	8259	HAMILTON RD	CAUTHORN	$79.14
975	3400	JACK CREEK	TWIN OAK SW	$64.27
967	44645	GIBBONS CRK	SINGLETON	$52.78
3391	44645	JEWETT	SINGLETON	$43.00
5211	5371			$41.91
I:DFW Ties				$40.00
1876	1880	WOLF HOLLOW	ROCKY CREEK	$30.63
3666	3670	HUTTO	ROUND ROCK NE	$28.79
2372	2373	COLLIN 345	ANNA SWITCH	$24.61
871	1695	COBISA_T1	MONTICELLO	$24.02
71067	71065	SWEETWATER	SWEETWATER	$17.40
7043	7046	HAYS ENERGY	KENDALL	$16.47

*Grey items are transformers

Economic Projects Tested (All Black lines 345kV Double Circuit except for Hays Kendall)

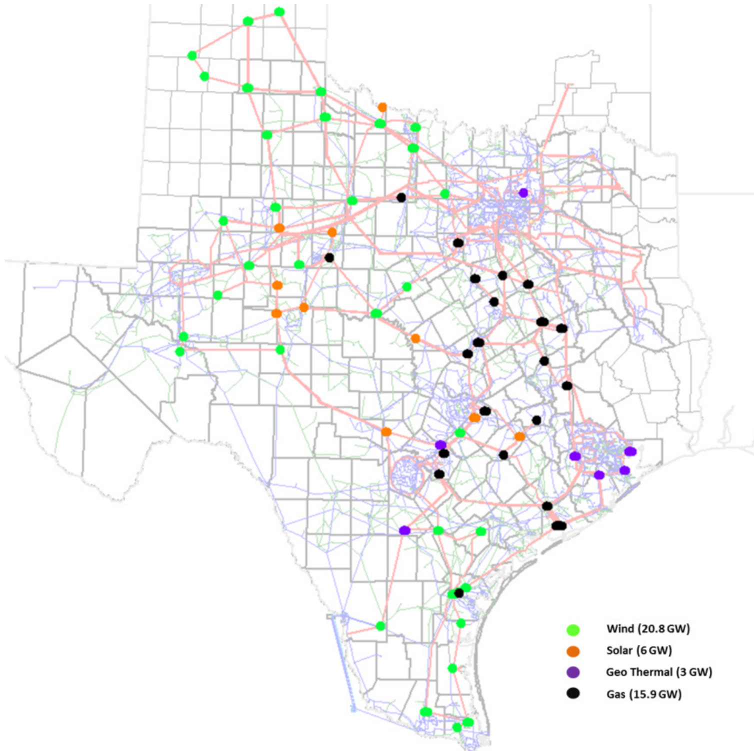


Economic Results

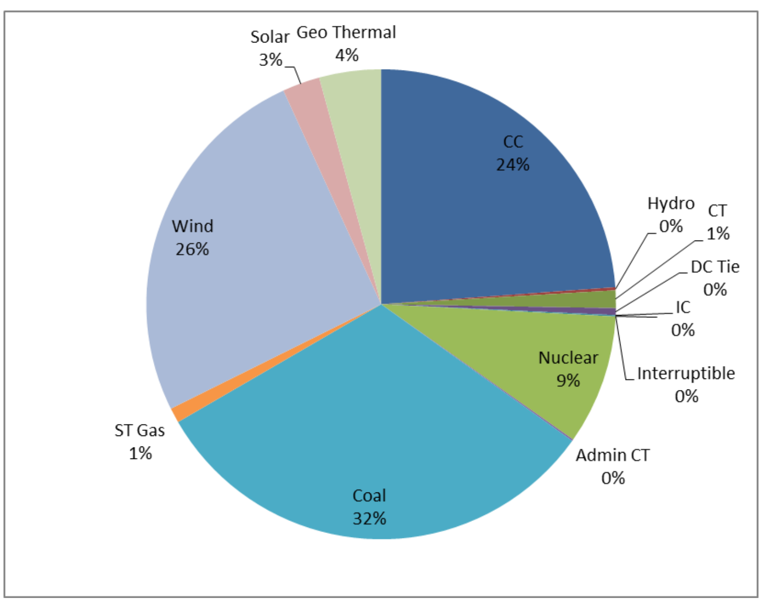
Tested Project	Capital Cost	Reliability benefit	Capital Cost Adjusted for Reliability Benefit	Production Cost Savings	1/6 of adjusted Capital Cost	Meet ERCOT Economic Criteria ?
Limestone-Singleton	163.6	9.7	153.9	26.1	25.6	**Yes**
Watermill-Bigbrown	208.2	153.0	55.2	0.6	9.2	**No**
Bigbrown-Venus	223.1	0.0	223.1	0.2	37.2	**No**
LakeCreek-Navaro	104.1	9.7	94.4	0.3	15.7	**No**
Lake Creek-Watermill	297.4	19.5	278.0	1.3	46.3	**No**
Clear Spring-Hill Country	104.1	0.0	104.1	3.1	17.4	**No**
Hays-Kendall	41.8	0.0	41.8	4.0	7.0	**No**
Sandow-Garfield	133.8	9.7	124.1	5.1	20.7	**No**

Scenario: Business as Usual with High Natural Gas Price - 2022

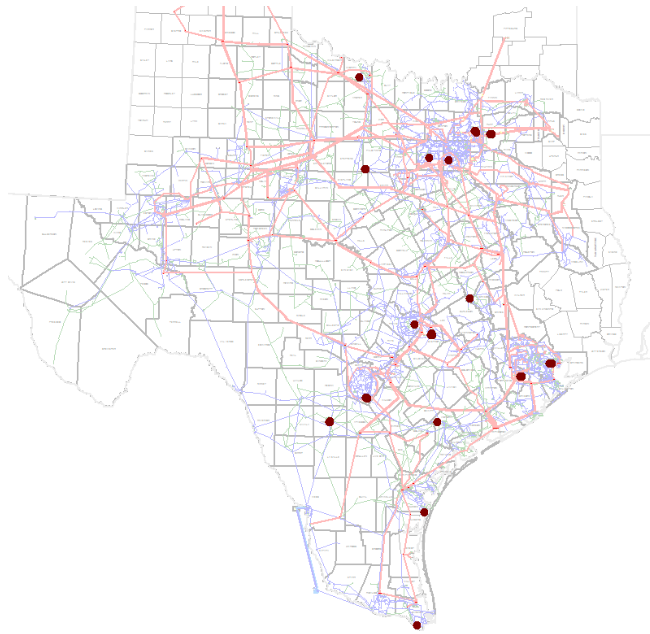
New Resources



Annual Generation Energy Mix:



Economic Retirement Resources



Sam Bertron 1/2
Mountain Creek 6/7
Pearsall 1-3
Powerlane Plant 1-3
RW Miller 1 - 2
Ray olinger 1 - 3
Sam Rayburn 3
Silas Ray
Witchita Falls 1
Barney Davis 1
Dansby 1
Decker Creek 2
Handley 3
Sim Gideon 1-3
VH Brauning 1-3
WA Parrish 1 -3

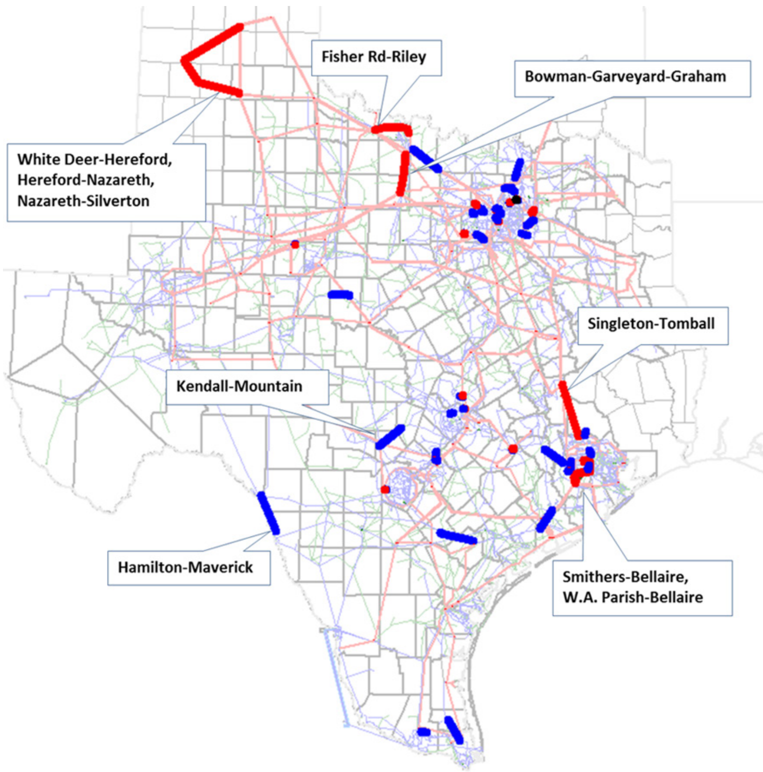
Peak load:
Hour: 8/4/2022 hour 16
System load (coincident peak): 89214 MW
Thermal & Hydraulic output: 70350 MW

Peak renewable:
Hour: 4/28/2022 hour 18
System load: 58017 MW
Renewable output: 22252 MW

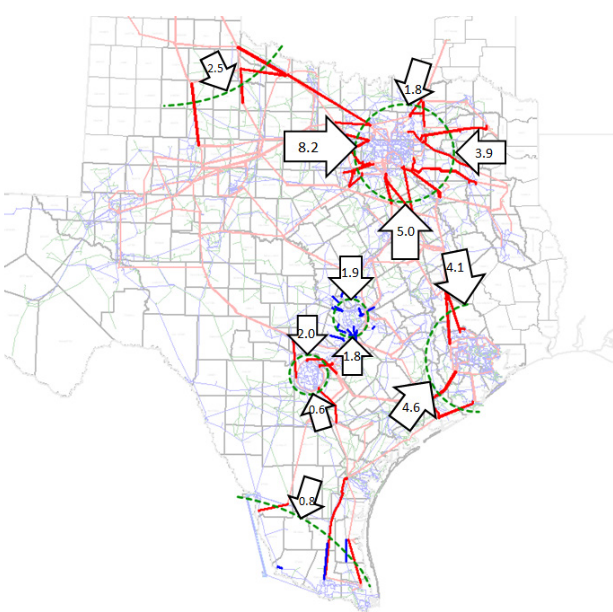
Import and Export limits determined by AC voltage stability analysis:

Area	Interface Limits (MW)	Potential year of voltage instability	Critical Contingencies (Under G-1 for Houston)
Dallas	19914	2025	Navarro-Watermill
Houston	9267.3	2028	Roans Prairie-Kuykendahl & Singleton-Tomball
Austin	4579	Beyond 2032	Hutto-Saladoss
San Antonio	3803	2031	Hill County - Marion and Skyline - Marion
Panhandle	6014.6	N/A	Dermot-Cottonwood
Valley	Not tested since incremental future generation in the region will only improve the system stability. Instead, previous interface limit was imposed at 2512 MW		

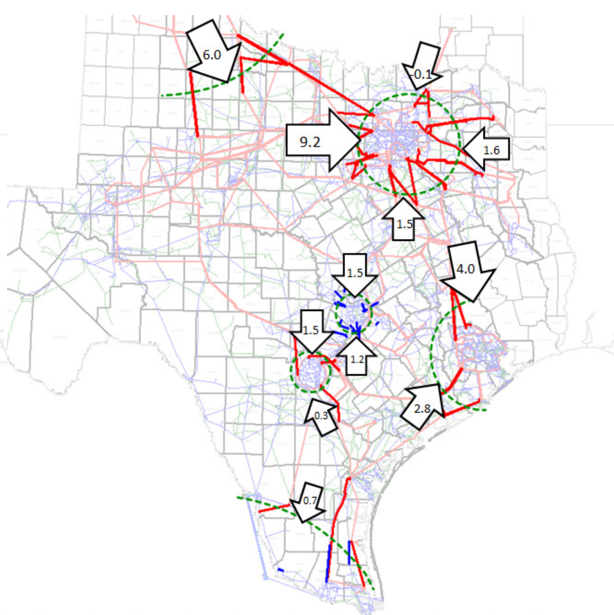
Base Case Overloads:



System flows at peak load hour:

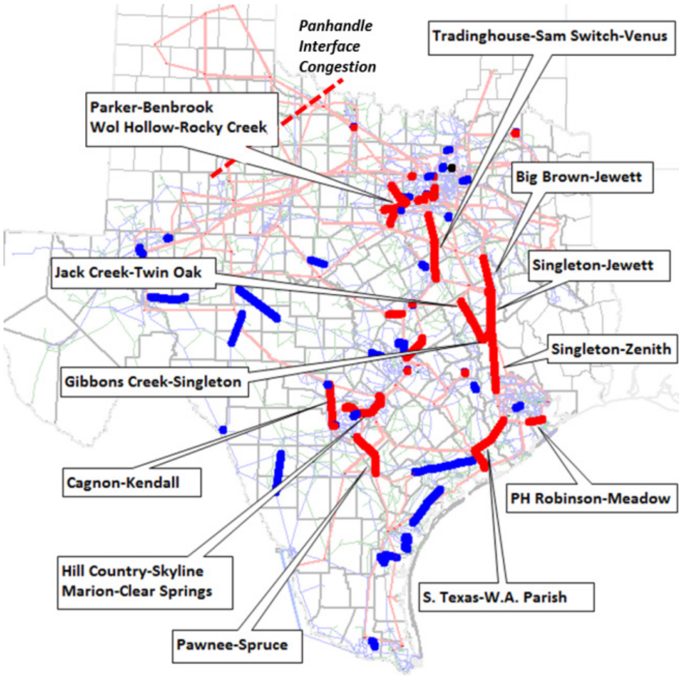


System flows at peak wind hour:



*All numbers are in GW

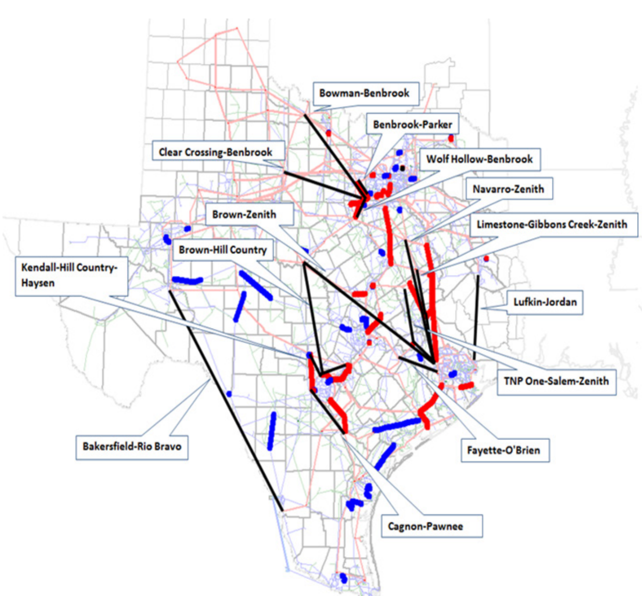
Congestion map:

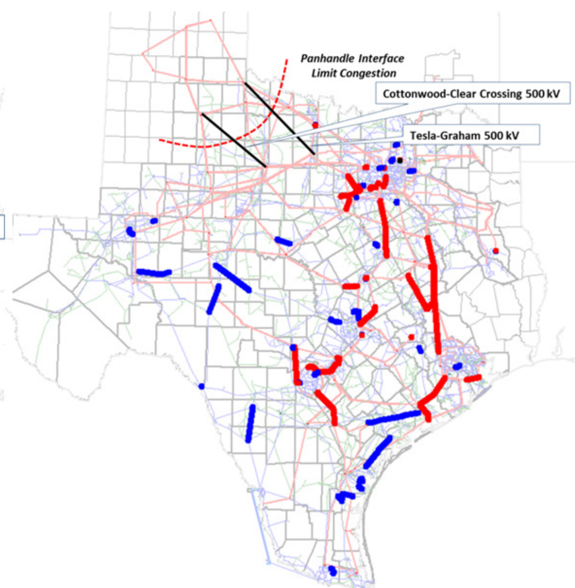


Most congested Elements:

FROM	TO	Name (FR)	Name (TO)	Congestion Cost ($M)
Panhandle Interface Limit				745
44645	44900	SINGLETON	ZENITH	446
1436	1873	PARKER	BENBROOK	193
3668	3670	ROUND ROCK	ROUND ROCK NORTHEAST	158
1855	2081	ALLIANCE	HICKS	108
3390	44645	JEWETT SOUTH	SINGLETON	102
967	44645	GIBBONS CREEK	SINGLETON	91

Economic Projects Tested





Economic Results

Tested Project	Capital cost	Reliability benefit	Adjusted Capital Cost for Reliability Benefit	Production Cost Savings	1/6 of Adjusted Capital Cost	Meet ERCOT Economic Criteria?
Bowman-Benbrook	$435.0	$ (188.90)	$623.9	$15.0	$104.0	No
Clear Crossing-Benbrook	$531.6	$ (145.30)	$676.9	$30.0	$112.8	No
Parker-Benbrook	$80.5	$ (145.30)	$225.8	$37.0	$37.6	Yes
Wolf Hollow-Benbrook	$162.6	$ (145.30)	$307.8	$28.0	$51.3	No
Fayette-O'Brien	$241.7	$ (52.33)	$294.0	$37.0	$49.0	No
TNP One-Salem-Zenith	$444.6	$ (73.15)	$517.8	$232.0	$86.3	Yes
Limestone-Gibbons Creek-Zenith	$391.4	$ (20.87)	$412.3	$274.0	$68.7	Yes
Brown-Zenith	$860.3	$ 25.99	$834.3	$236.0	$139.0	Yes
Lufkin-Jordan	$439.1	$ 13.72	$425.4	$190.0	$70.9	Yes
Navarro-Zenith	$597.8	$ (57.60)	$655.5	$208.0	$109.2	Yes
Cagnon-Pawnee	$241.7	$ 23.12	$218.5	$4.0	$36.4	No
Kendall-Hill Country-Haysen	$338.3	$ 60.03	$278.3	$26.0	$46.4	No
Brown-Hill Country	$507.5	$ 4.57	$502.9	$125.0	$83.8	Yes
Bakersfield-Rio Bravo	$978.7	$ 27.40	$951.3	$94.0	$158.5	No
Cottonwood-Clear Crossing, Tesla-Graham 500 kV	$970.7	$ 15.82	$954.9	$117.0	$159.1	No

*All numbers are in millions in 2022.