



ERCOT Interconnection

Long-Term Transmission Analysis 2012 – 2032 Final Report

Electric Reliability Council of Texas, Inc.

Topic A and B Final Report

Volume 2

December 2013

Federal Acknowledgement and Disclaimer

This material is based upon work supported by the Department of Energy [National Energy Technology Laboratory] under Award Numbers DE-OE-0000340 and DE-OE-0000341.

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Appendix S ERCOT Solar Generation Patterns

ERCOT Solar Generation Patterns

Project Summary Report

URS Report to ERCOT

ERCOT Solar Generation Patterns

Project Summary Report

March 8, 2013

URS

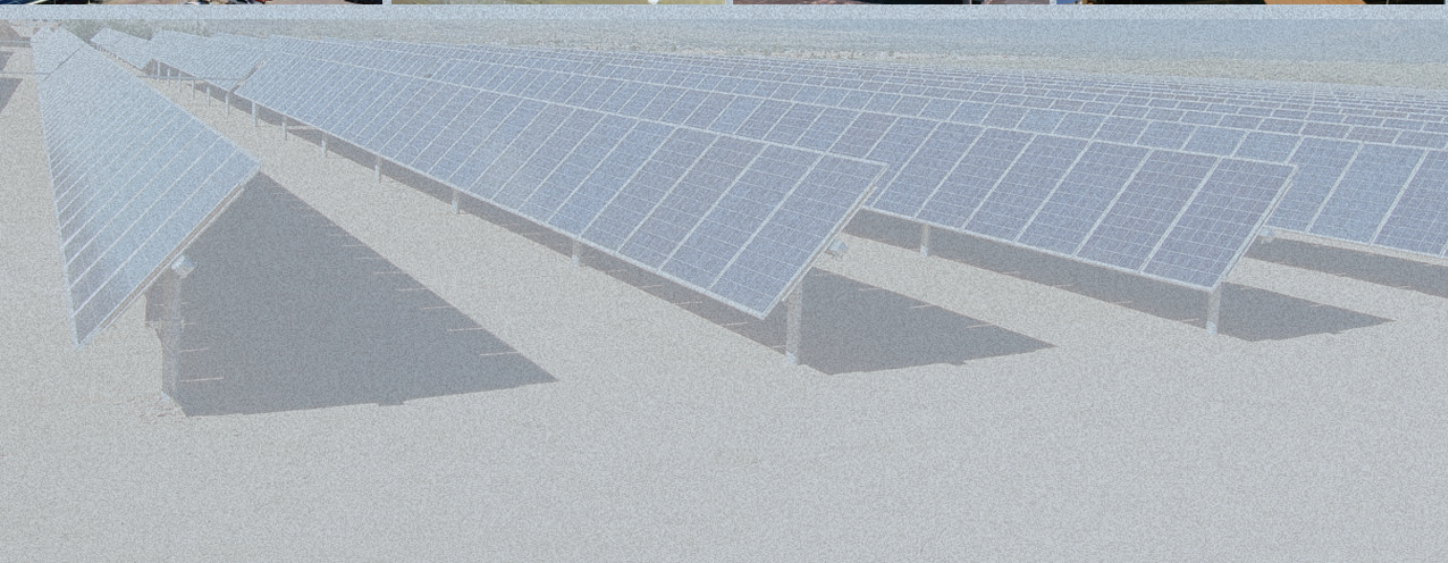


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Project Overview

In order to better understand the potential implications of widespread installation of solar electricity generation capacity across Texas and assist in long-range planning efforts, ERCOT requires detailed estimates related to the magnitude and timing of electricity production from potential solar installations of different sizes, technologies, and geographical locations. Using 20 years of historical meteorological and solar radiation data (1991-2010), URS utilized specialized modeling software to generate 20 years of estimated hour-by-hour electricity output for four solar technologies in each of the 254 counties in Texas. The resulting database provides a robust tool by which ERCOT can incorporate different solar deployment scenarios into its existing models.

The project was divided into five Tasks:

- **Task 1: Data Collection**
 - Collection of historical meteorological and solar radiation data for Texas
 - Conversion of data into format compatible with modeling software
- **Task 2: Model Development**
 - Configuration of individual models for four solar technologies: fixed tilt crystalline (1 MW), single-axis tracker (1MW), concentrating solar power (50MW), and rooftop residential (5 kW).
 - Group each of the 254 Texas counties with a Class I or Class II weather station based on proximity, solar radiation profile, elevation, and other factors.
- **Task 3: Run model simulations**
 - Feed raw meteorological and solar radiation data through the configured models to produce hour-by-hour DC and AC production estimates for the years 1991-2010, plus a single “typical meteorological year (TMY)” for each raw dataset.
 - With 34 weather stations included in the analysis and each weather station having 20 years of data plus a TMY year, the result of Task 3 is 2,856 ($43 * 21 * 4$) individual data files each representing a full year of hourly electricity production estimates based on the configuration of the associated technology.
- **Task 4: Sensitivity and Uncertainty Analysis**
 - QA/QC of the produced data
 - Variance analysis through comparison of results using nearby weather station data
 - Statistical variability calculations for a sampling of sites
- **Task 5: Prepare Final Report and Presentation**

This report describes the processes and methodologies used in collecting and generating the data and summarizes the results of the final production model data output. It is organized into four sections:

- 1: Solar Radiation & Meteorological Data
- 2: Extrapolation of Weather Station Data
- 3: Solar Production Modeling
- 4: Statistical Analysis

1: Solar Radiation & Meteorological Data

URS collected both historic and typical weather and solar radiation data for weather stations across Texas to use as inputs to the solar models. The historical weather data was obtained in the National Climatic Data Center (NCDC) format and the typical year data was obtained in the TMY3 format. Both of these sets of weather data are part of the 1991-2010 National Solar Radiation Database (NSRDB) and were downloaded from the US Department of Energy National Renewable Energy Laboratory (NREL) website. The NSRDB 1991-2010 update contains 20 years of historical weather data for a total of 89 weather stations across Texas. URS downloaded all available historical data for Texas and data from four additional stations in adjacent states. TMY3 data developed as part of the NSRDB 1991-2010 update was available for 61 of the weather stations in Texas and all four of the stations in neighboring states. URS created a directory for each of the historical NSRDB weather stations following the naming convention, “Station_Name-USAFStationIdentifier” within the directories “NSRDB Historical Weather Files” and “NSRDB Historical Weather Files-notInTX”. Similarly, URS created directories for each of the typical year weather stations, which are a subset of the NSRDB stations, following the naming convention, “Station_Name-USAFStationIdentifier-StationQualityClassification” within the “TMY3 Files” and the “TMY3 Files-notInTX” directories.

The collected weather data contains records of the ambient conditions for each hour of the year. The solar radiation data and ambient conditions data are the primary drivers of the energy production models. The energy production models are most sensitive to the selection of parameters within the weather data files that are presented in Table 1. The highlighted rows distinguish weather data input values with particular influence on energy production models of photovoltaic (PV) and concentrating solar power (CSP) electricity generating systems. Some psychrometric parameters not included as raw data in the weather input files are calculated by the energy production model from the available parameters when necessary.

Table 1: Typical Required Weather Data for Solar Simulations

Entry	Units
Dry-bulb temperature	°C
Dew-point temperature	°C
Relative humidity	%
Wind speed	m/s
Wind direction	deg
Atmospheric pressure	mbar
Global horizontal radiation	W/m ²
Direct normal radiation	W/m ²
Direct horizontal radiation	W/m ²

Source: System Advisory Model (SAM) Weather Data Documentation- 12/7/2011

National Solar Radiation Database (NSRDB)

The 1991-2010 National Solar Radiation Database is a collection of measured and modeled solar radiation data with accompanying meteorological fields for a period of 20 years for weather stations across the United States. The current NSRDB data set is an update to a dataset for 1991-2005, which was released in 2007. The most current dataset (1991-2010) was released in 2012.

The NSRDB data is almost entirely composed of data generated by the NREL Meteorological-Statistical Model (METSTAT). NREL used ground-based measurements of weather data from the weather stations included in the NSRDB dataset as inputs to the METSTAT model to produce values for the ground-level solar radiation. NREL used actual measured ground radiation, available for a limited number of sites, to validate the METSTAT model. When available, the measured data is included in the NSRDB data files in addition to the modeled ground level radiation data. No additional measured solar data beyond 2005 were included in the 1991-2010 update.

NREL's objective was to produce the 1991-2010 NSRDB as a serially complete dataset for the entire period of record. To accomplish this goal NREL employed four levels of data-filling methods. These are short-term interpolation, up to 5 hour gaps and gaps at night; medium-term filling, gaps up to 24 hours; long-term filling, gaps up to 1 year; last-ditch filling, gaps greater than a year. NREL used the quantity of data filling required to produce a serially complete dataset as a contributing factor when determining the uncertainty of the NSRDB dataset. The results of the uncertainty analysis contribute to the classification of a weather station as Class I, Class II, or Class III.¹

The NCDC provided all of the meteorological data used to input the NSRDB dataset. The University of Texas Solar Energy Laboratory, University of Oregon Solar Radiation Monitoring laboratory network, and other similar radiation monitoring networks provided the ground-level solar radiation measurements.

The 1991-2010 NSRDB dataset is available in multiple formats from different sources. URS has downloaded data in the (NCDC) format from the NREL website.²

For a complete list of the fields in the NCDC formatted 1991-2010 NSRDB dataset and an in depth description of data sources and the data production methodology please refer to the *National Solar Radiation Database 1991-2010 Update: User's Manual*.³

¹ National Solar Radiation Database 1991-2010 Update: User's Manual, Stephen Wilcox, 2010, p. 50-51.

http://rredc.nrel.gov/solar/old_data/nsrdb/1991-2010/#doc

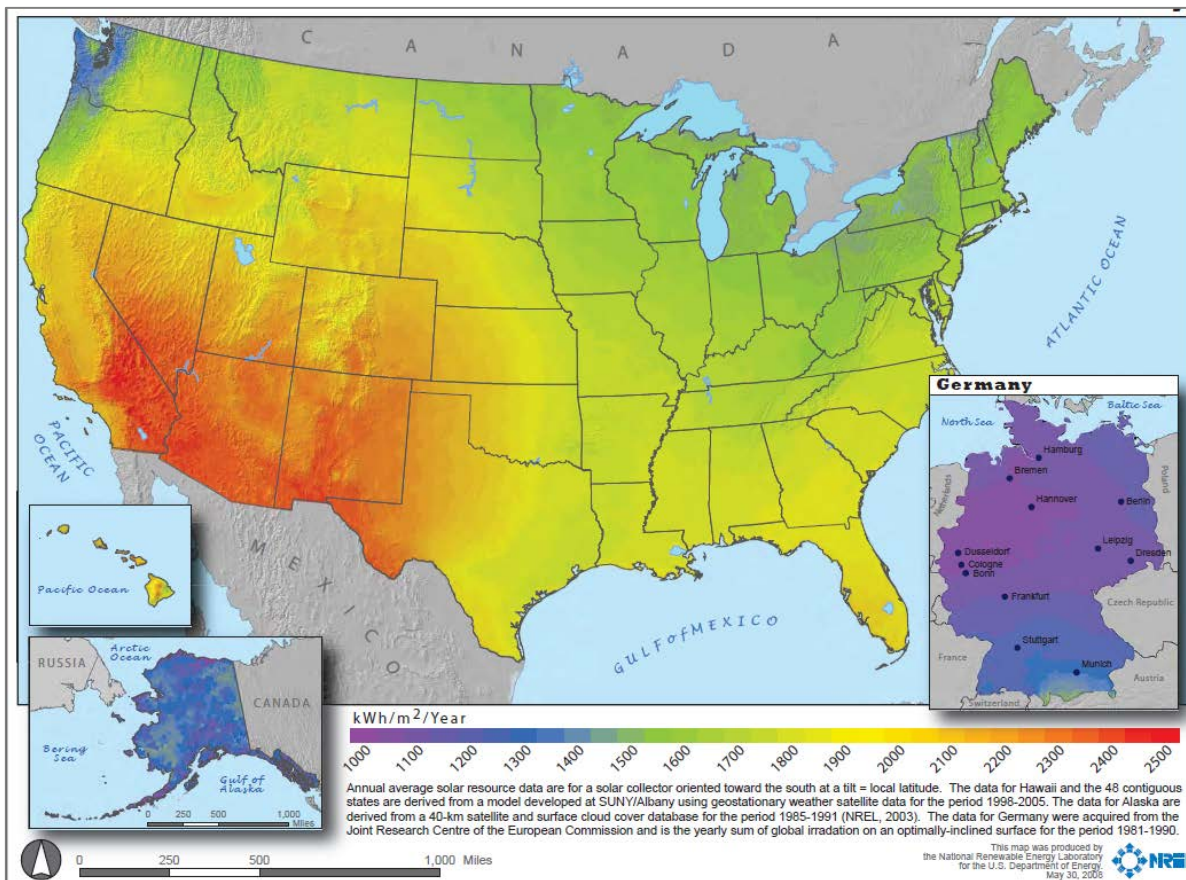
² "Distribution of the NSRDB is authorized through the National Climatic Data Center (NCDC), which has experienced some ingest and cataloging delays for the updated NSRDB. To expedite release of this data set to users, NREL has received temporary authorization for distribution of all NSRDB products."

http://rredc.nrel.gov/solar/old_data/nsrdb/1991-2010/

³ National Solar Radiation Database 1991-2010 Update: User's Manual, Stephen Wilcox, 2010,

http://rredc.nrel.gov/solar/old_data/nsrdb/1991-2010/#doc

Figure 1: Photovoltaic Solar Resource in US and Germany



Source: US DOE, National Renewable Energy Laboratory

Typical Meteorological Year (TMY)

A typical meteorological year (TMY) dataset provides hourly values of solar and weather data for a year, which typify the conditions of a particular geographic location for a significant period of time. The TMY3 data that URS downloaded and used as inputs for the solar energy production models is based on data produced by the 1961-1990 NSRDB, Version 1.1 and the 1991-2005 NSRDB update.⁴

The TMY3 datasets are created using a modified procedure first developed by Sandia National Laboratories. The procedure to create the TMY3 dataset compares months based on 10 daily indices. These indices are the Max Dry Bulb Temperature, Min Dry Bulb Temperature, Mean Dry Bulb Temperature, Max Dew Point Temperature, Min Dew Point Temperature, Mean Dew Point Temperature, Max Wind Velocity, Mean Wind Velocity, Global Radiation, and Direct Radiation. The TMY3 process selects the historical month with values for these indices most closely matching the

⁴ User's Manual for TMY3 Data Sets, S. Wilcox and W. Marion, May 2008, p.1, <http://www.nrel.gov/docs/fy08osti/43156.pdf>.

typical values of the entire time period with available data. Where discontinuities are created between months due to this process, they are smoothed for 6 hours on each side.⁵

The resulting TMY dataset contains time-series meteorological measurements and modeled solar values representing typical years for each hour of the year. Building designers are the most frequent users of these TMY files. The TMY format provides a useful input to models of building physics that can assist in sizing building mechanical systems for typical weather. As an input to solar energy production models, TMY files produce an estimate for the solar energy produced in a typical year. However, energy production models produced with TMY input files do not account for year-to-year fluctuations in the solar resource caused by volcanic eruptions, El Niño and La Niña cycles, and sun spot cycles.⁶

Data Format Conversion

URS used the NREL System Advisor Model (SAM) to model the four solar technologies and generate annual estimates of their energy production. SAM reads weather data files that are in the TMY2, TMY3 or the EPW format. The NCDC-formatted NSRDB data was converted to the TMY3 format for use as an input to SAM. The conversion process was automated using Bash shell scripts and Unix programming languages, including AWK and SED.

URS developed a script to automate the process of converting each of the 1,860 (20 years for each of the 93 weather stations) annual weather data files from the NCDC NSRDB format to the TMY3 format. Each of the NSRDB formatted historical weather files is named with the convention “NSRDB_StationData_yyyymmdd_yyyymmdd_USAFStationIdentifier.csv”, where the first date is the first day of record and the second date is the last day of record. The *USAFStationNumber* is the United States Air Force Station Identifier. The weather file format conversion script produces a file with the same name, but the file extension “.tm3”. *Please note that although the extension assigned to the converted NSRDB historical weather files is the same as the TMY3 files, the converted file is not a typical year file.* The “.tm3” file extension is used to denote that the converted weather file is in the same format as the typical year file.

The conversion process reformats the date and time stamp to the TMY3 format and reorders the fields (columns) in the NCDC formatted NSRDB data to match the TMY3 fields. The conversion process includes measured solar radiation data in the converted file when available. The TMY3 file format contains 68 fields while the NCDC NSRDB data format contains only 49 fields. Fields present in the TMY3 file for which no data was available in the NSRDB data were filled with a value of “-9900” indicating a missing value. A table of the conversion process which shows the field labels for both file formats is included in Appendix I. Due to the differences in the conventions used for fields indicating the source of the data, many of these fields are filled with the TMY3 flags for missing data. Similarly, some of the uncertainty fields are filled with the TMY3 flag for undefinable uncertainty. Where available uncertainties provided as percentages were carried through the conversion process. In part to maintain a record of these flags the conversion process generates a report file for each weather file converted. The report file contains 6 header rows above the weather data in the TMY3 format, but with the original NSRDB source and uncertainty flags. The header rows provide a summary ‘map’ to the conversion process. The report files follow the naming convention,

⁵ User’s Manual for TMY3 Data Sets, S. Wilcox and W. Marion, May 2008, <http://www.nrel.gov/docs/fy08osti/43156.pdf>.

⁶ P50/P90 Analysis for Solar Energy Systems Using the System Advisor Model, A. Dobos, P. Gilman, M. Kasberg, June 2010.

"NSRDB_StationData_yyyymmdd_yyyymmdd_USAFStationIdentifier-convReport.rep". Please note that all files with the ".tm3" and the ".rep" are comma-separated value files.

The weather data was further processed prior to use as inputs to the SAM energy production models because SAM only simulates 8,760 hours per year. This limitation prevents SAM from correctly processing leap years. SAM uses the data for February 29th if it is present within a weather input file, but will fail to process the data for December 31st. To maintain consistency between simulations URS archived the leap year weather files and generated a copy of the annual weather file without the data for February 29th. The archived leap year weather files were appended with the ".leap" extension, but remain in the comma-separated value format.

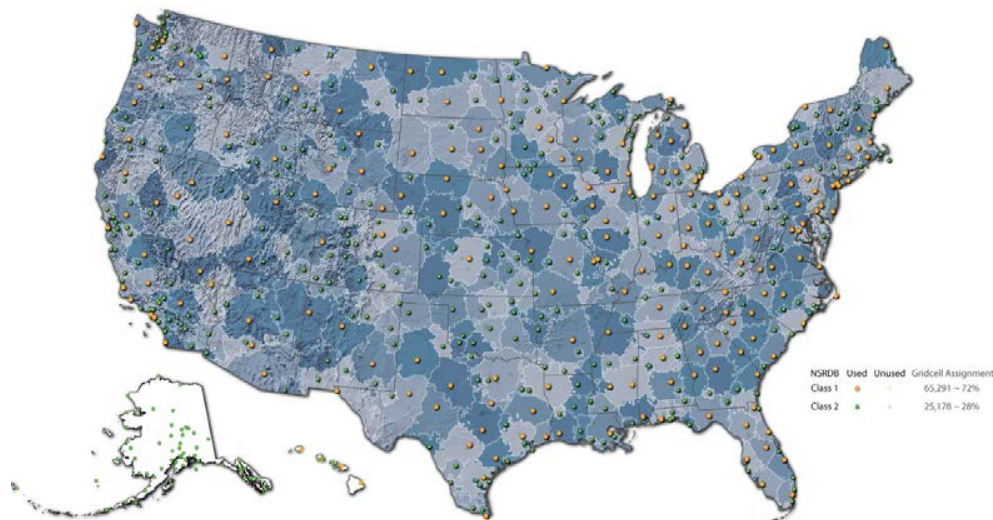
2: Extrapolation of Weather Station Data

ERCOT requested meteorological and solar production data spanning at least 15 years for each county in Texas. The meteorological data originates from NSRDB weather stations which are classified according to the quality of the historical dataset associated with that station. Class I Stations have a complete period of record (all hours 1991–2010) for solar and key meteorological fields and have the highest quality solar modeled data (16 sites in Texas). Class II Stations have a complete period of record but significant periods of interpolated, filled, or otherwise lower-quality input data for the solar models (37 in Texas). Class III Stations have some gaps in the period of record but have at least 3 years of data that might be useful for some applications (36 in Texas). Since at least 15 years of high-quality data was required for this analysis, only Class I and Class II weather station data was used. With 53 Class I and II weather stations in Texas and 254 counties, an extrapolation process was developed by URS to create groups of counties around each weather station. This section of the report describes the methodology used to develop the weather station-county groupings and provides a summary of the results.

Grouping Methodology

In 2011 NREL generated a map of the United States that delineates “areas of influence” around each NSRDB Class I and II weather station in the country. The purpose of this delineation is to provide an indication of which solar radiation and meteorological dataset is most appropriate for modeling a given solar installation’s location. The zones around each weather station were defined by NREL to a granularity of 10km² using solar radiation profile, elevation and proximity as the main variables in an algorithm used to group each 10km² grid to the Class I or II weather station that represents the best match for that grid (see Figure 2).

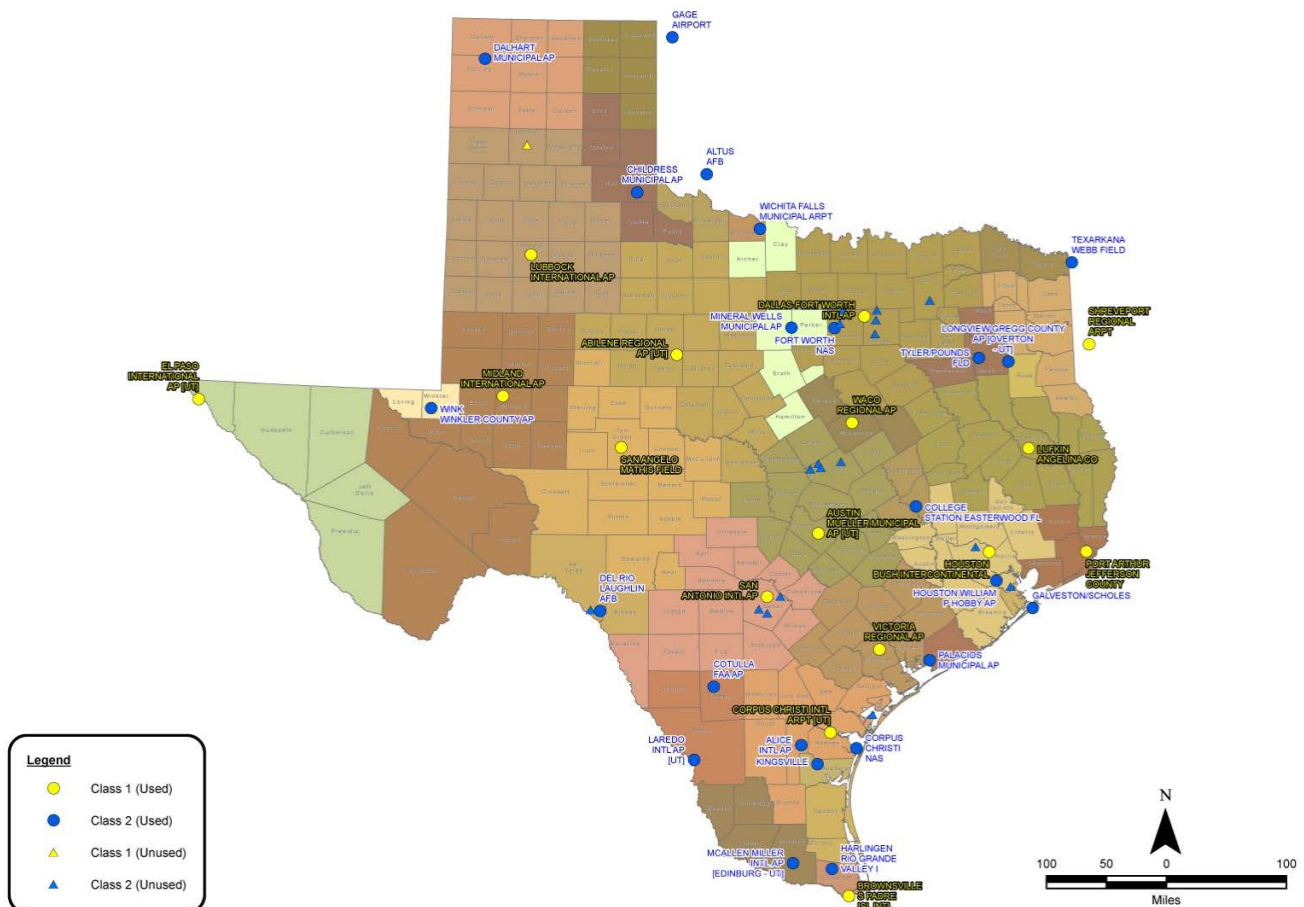
Figure 2: NREL NSRDB Weather Station "Areas of Influence" Map



Source: US DOE, National Renewable Energy Laboratory

Because of overlapping “areas of influence” caused by the close proximity of several weather stations in Texas, 19 of the 53 Class I and II weather stations in Texas were excluded due to redundancy from the NREL map. URS used the information contained in the NREL map as the basis for grouping each county to the most representative of the 34 Class I or II NSRDB weather stations. This was done by calculating the percentage of geographical coverage of each county by different “areas of influence” and assigning a county to the one weather station that represented the highest percentage of its total coverage. For example, if a county contained 45% of Zone A, 30% of Zone B, and 25% of Zone C, the county was assigned to Weather Station A. Four weather stations from outside of Texas were identified as the best fits for some border counties. Figure 3 below shows the location of both the used and unused Class I and II weather stations in Texas along with the corresponding counties that have been grouped with the 34 “used” weather stations. See Appendix II for a complete listing of the weather stations used in this analysis and the counties grouped to each.

Figure 3: Weather Station-County Groupings



Source: URS GIS Dept.

3: Solar Production Modeling

URS utilized the NREL System Advisor Model (SAM) to produce energy production estimates for four different solar system configurations for geographic locations across Texas. This section of the report describes the assumptions and inputs used to model a 1MWe-AC fixed tilt photovoltaic (PV) solar system (PVFT), a 1-MWe-AC single-axis tracking PV system (PVSAT), a 5kWe-AC residential PV system (RES), and a 50MWe-AC parabolic trough concentrating solar power system (CSP).

National Renewable Energy Laboratory (NREL) System Advisor Model (SAM)

SAM was first jointly developed in 2005 as an internal systems-based solar analysis tool by NREL and Sandia National Laboratories. The first commercial version of SAM was released in 2007. URS downloaded and utilized the most recent version of SAM, SAM 2013.1.15, for all solar energy production modeling for this project.⁷ URS selected SAM from among the other modeling software options like PVSyst because of its integration with historic weather data, modeling functionality, and the alignment of its model results with the intended analytical use by ERCOT.

SAM includes a variety of physical models of different solar technologies which can be customized through user input selections. Additional control and automation of SAM simulations is provided through the built-in SamUL scripting language. SAM includes a variety of financial models in addition to the physical models of solar technologies. The simulations URS performed did not utilize any of the financial modeling capabilities of SAM.

URS utilized the “Flat Plate PV” model to simulate the performance of the PVFT, PVSAT, and the RES systems and the “CSP Physical Trough” model to simulate the CSP system. The PVFT, PVSAT, and RES models are distinguished by the equipment and tracking parameters specified for each model. The assumptions and inputs for each of these models are described in the remainder of this section.

Solar Technologies Overview

Fixed Tilt Crystalline Silicon

The majority of fixed tilt PV arrays utilize modules composed of individual crystalline silicon (C-Si) cells. Crystalline silicon (C-Si) is the most common type of solar cell and consequently has the lowest initial cost per installed watt of all solar PV technologies. C-Si cells can be further differentiated into either monocrystalline or polycrystalline silicon. Monocrystalline silicon cells are cut from cylindrical ingots of single-crystal silicon. Polycrystalline silicon cells are cut from large blocks of silicon containing many individual crystals and are typically less efficient and less expensive than monocrystalline silicon cells. The module conversion efficiency, or percentage of the sun’s energy that is converted into electricity, of commercially available C-Si modules is between 13-16% for polycrystalline modules and 14-20% for monocrystalline modules.

Fixed tilt systems utilize driven piles, ballast, or concrete footers as a foundation for a metallic racking structure which holds the PV modules at a fixed orientation. The ideal orientation to maximize annual

⁷ NREL System Advisor Model (SAM) 2013.1.15 Help

energy output from a fixed tilt solar array is with an azimuth pointed due south and a slope (or tilt) of the modules equal to the latitude of the solar array installation location.⁸ The ideal orientation for maximum energy production maintains the plane of the solar module normal to the sun through the day and year. Fixed tilt systems produce less energy than single-axis or dual-axis tracking systems due to their below optimal orientation but require less capital expense and maintenance costs compared to tracking systems which would be required to maintain an optimal orientation.

The solar modules are electrically connected serially in 'strings'. The number of modules which can be connected in series is dependent on the maximum input voltage of the inverter and the ambient temperatures of the site. The voltage of the solar module is inversely related to the operating temperature of the solar cells. The output of paralleled groups of strings are brought together and combined at an inverter, which converts the DC power produced by the solar modules to AC power for consumption or distribution to the electric grid.

The nameplate rating of solar modules is determined based on testing performed at Standard Test Conditions (STC). For PV testing, these are an irradiance of 1000 W/m², a solar spectrum of AM 1.5, and a temperature of 25°C.

Single-Axis Tracking (SAT)

Single-axis tracking (SAT) systems increase the energy produced by a solar array by tracking the sun from east to west diurnally. The tilt of SAT systems are usually kept flat, normal to the zenith, and have a total east-west tracking range of 90°. A control algorithm keeps the solar modules tilted toward the sun throughout the course of the day.

A range of configurations exist for SAT, but the most common is north-south rows of piles supporting a single torque tube to which individual modules are mounted. The tracking motion of groups of rows is provided through a mechanical linkage and a common drive motor.

SAT systems are designed to maximize land use without causing self-shading. The balance of system (BOS) components of a SAT system are similar to those of a fixed-tilt system.

Residential Rooftop Solar

Residential solar utilizes the same components of a fixed-tilt system, but is constrained to the orientation of the building roof. Also, the physical size and electrical capacity of residential components are less than those of a utility scale SAT or fixed-tilt system.

Residential solar arrays typically range from 2kW to 16kW. The BOS may be minimal for a residential system; strings of solar modules may be electrically connected directly to the solar inverter, which is in turn connected to the electrical distribution panel of the residence.

⁸ "The slope is the angle between the plane of the surface in question and the horizontal...The surface azimuth angle is the deviation of the projection on a horizontal plane of the normal to the surface from the local meridian." The - Duffie, J.A. & Beckman, W. A. (2006). *Solar engineering of thermal processes* (3rd ed.). Hoboken: John Wiley & Sons.

CSP

Concentrating solar power (CSP) plants utilize concentrated solar radiation to generate thermal energy, which is used to power a conventional electricity producing steam turbine generator. There are two primary types of power concentrating solar power plants: parabolic troughs and power towers.

Parabolic troughs utilize long parabolic mirrors to concentrate solar radiation on a tubular absorber which is held in the focal point of the mirror. The parabolic troughs track the sun along a single north-south axis from east to west throughout the day. Power towers use arrays of mirrors (heliostats) which track the sun over two axes and focus the radiation on a single fixed absorber which is elevated above the field of heliostats. URS elected to model a parabolic trough type CSP plant due to the historical data available from plants of this type constructed in the US (see Appendix III).

CSP plants often utilize thermal energy storage (TES) to increase the plant capacity and smooth short-term transients in the available solar radiation. TES systems for current CSP plants utilize a two-tank indirect molten salt storage system.⁹

Production Modeling Methodology Overview

The following sections detail the value URS selected for the significant user inputs for each solar model.

PV Fixed Tilt Model (PVFT)**PV Module Selection**

URS performed a parametric study of four solar modules to select a module for use in the PVFT model. The candidate modules are all typical 72-cell solar modules produced by large manufacturers which supply modules to utility scale solar development projects.

Table 2: Parametric Study of Four Solar Modules

	Mod/ String	Parallel Strings	Inverters	kW-DC	kW-AC	DC/AC	Nominal DC Energy (kWh- DC)	Net DC Output (kWh-DC)	% DC Losses	Net AC Output (kWh-AC)
Yingli- YL285P-35b	12	358	2	1223.11	1000	1.22311	2,244,300	1,974,950	-13.64%	1,897,690
MEMC-P285AMC-24	12	358	2	1225.73	1000	1.22573	2,249,090	1,952,760	-15.17%	1,876,720
Suntech STP285-24-Vd	12	358	2	1222.68	1000	1.22268	2,243,510	1,982,600	-13.16%	1,904,120
Trina TSM-285PA14A	12	358	2	1224.23	1000	1.22423	2,246,350	2,003,450	-12.12%	1,923,440

SunEdison, a subsidiary company to MEMC, is a solar developer that has developed several projects within Texas using MEMC modules. Additionally, Yingli was the largest module supplier in 2012.¹⁰ This parametric simulation held constant all values except the module parameters. The average DC losses, which are only affected by the module parameters, is -13.52%. This average value most closely matches

⁹ Thermal Storage Commercial Plan Design Study for a 2-Tank Indirect Molten Salt System, B. Kelly and D. Kearney, NREL.

¹⁰ Top 10 PV module suppliers in 2012, PVTECH, January 28th, 2013, http://www.pv-tech.org/guest_blog/top_10_pv_module_suppliers_in_2012

the loss by the Yingli module. URS selected the Yingli-YL285P-35b module for use in the PVFT simulation due to the prevalence of Yingli modules and the degree to which they provide typical performance for a range of modules commonly used in utility scale PV plants.

Inverter Selection

URS selected the SMA 500HE-US 200V inverter equipment model for use in the PVFT model. SMA is among the industry leading manufacturers of utility-scale central inverters. The use of (2) 500kW-AC inverters in the model provides an even 1MW-AC capacity, which allows the output data to be easily scaled to provide approximate energy production for a range of plant capacities 1MW-AC or greater.

The SMA 500HE-US inverter has a maximum input voltage (DC) of 600V. It is increasingly common to design utility-scale PV plants around central inverters with a 1000V DC input voltage. However, the inverter equipment models available do not include a 1000V inverter with a rated output power of 500 kW-AC. URS deemed the departure from the most likely equipment configuration for future plants acceptable to provide energy production results for 1MW-AC system. Possible differences between a simulation with a 1000V inverter and a 600V inverter of the same capacity include changes in DC wire losses and inverter efficiencies. URS did not quantify these potential differences in efficiency.

Array Sizing

The number of modules in each string was selected based on statistical weather data compiled by the American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE). The lowest temperature used to calculate the string voltage is 11°F (-11.67°C), which is the 97.5% design dry-bulb temperature for the Amarillo AP. This is the lowest temperature expected for 97.5% of winter hours. This is the lowest winter design-dry bulb temperature for the locations in Texas listed in the source.¹¹ The ASHRAE statistical temperature data is referenced by the National Fire Protection Agencies 2011 National Electric Code Handbook, section 690.7.

The number of parallel strings was determined by calculating the DC power necessary for the ratio of DC power to AC power to be 1.2. This is a common ratio in the industry, which reduces time the inverter is underpowered due to ambient conditions differing from the standard test conditions.

Array Orientation

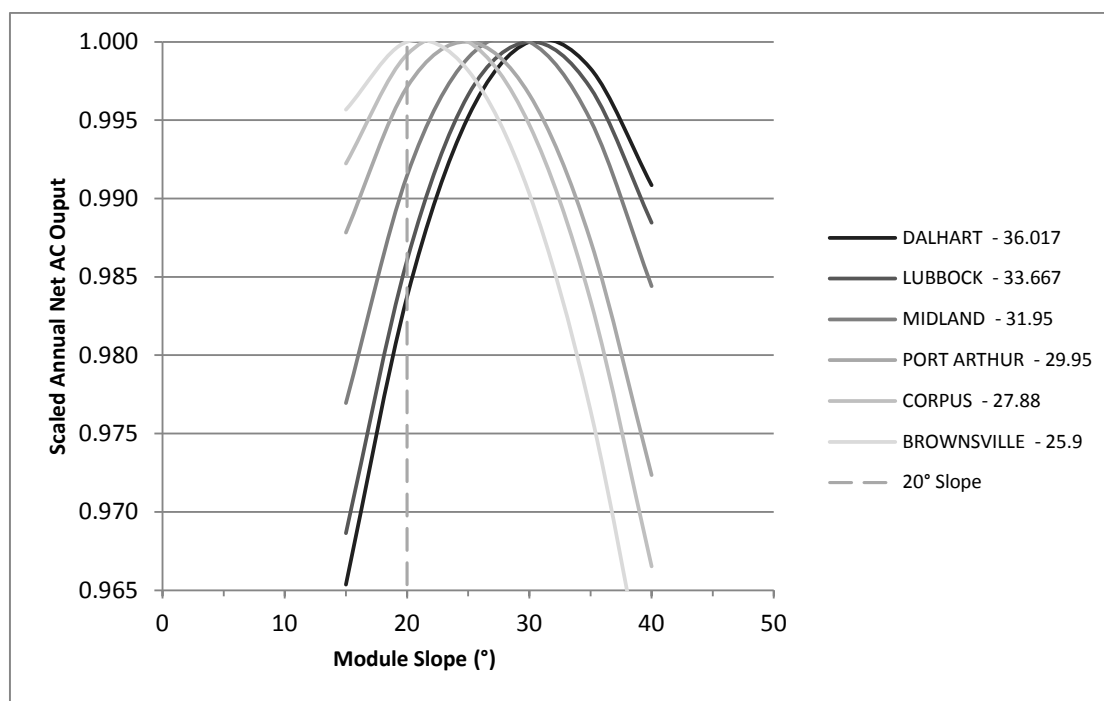
URS performed parametric simulations to inform the selection of a module slope for the PVFT model. The parametric simulations held all input values constant, except for the weather input file (location). URS set the slope for the parametric simulations to 25°. The results of the parametric simulation express the relationship between slope and power input. The results are also influenced by the site specific weather conditions, but the correlation between annual energy generation, slope, and latitude is readily apparent despite the effects of localized weather conditions. The results of the parametric simulation are shown in the figure below.

URS selected a slope of 20° for the PVFT model. This is below optimal for the weather stations in the northern part of Texas. However, as shown in Figure 4, the reduction in power output for a system with modules oriented with a 20° slope is less than 2% from the optimum production. Additionally, the lower module slope allows reduced north-south row-to-row spacing within the solar array. For solar arrays with a limited land area, the reduced row-to-row spacing generally allows for a greater total system

¹¹ Mechanical and Electrical Equipment for Buildings. Benjamin Stein, John S. Reynolds, Walter T. Grondzik, and Alison G. Kwok. 10th Ed. 2006, Hoboken, NJ: John Wiley & Sons, Inc.

capacity (kW-DC). This greater capacity generally results in energy production, which exceeds the losses from a non-optimal slope. URS used a system azimuth as due south for the PVFT model.

Figure 4: Parametric Simulations of Module Slope



System Losses

URS specified system losses which are typical for design values of utility-scale solar systems as model input parameters. These include AC and DC wiring losses of 0.5% and 1.5%, respectively. A 0.3% loss is included for one day of system unavailability per year. This loss is added to the -0.67% annual light induced degradation to determine the 99.03% value for the percent of annual system output adjustment.

Summary of Input Parameters

Table 3: PV Fixed Tilt – Module Input Parameters

Module: Yingli Energy (China) YL285P-35b						
Module Characteristics at Reference Conditions						
Efficiency	14.60	%	Temperature Coefficients			
Maximum Power (Pmp)	284.71	Wdc	-4.700e-001	%/C	-1.338e+000	W/C
Max Power Voltage (Vmp)	35.5	Vdc				
Max Power Current (Imp)	8.02	Adc				
Open Circuit Voltage (Voc)	45	Vdc	-3.430e-001	%/C	-1.543e-001	V/C
Short Circuit Current (Isc)	8.5	Adc	4.320e-002	%/C	3.672e-003	A/C
Physical Characteristics						
Material	Multi-c-Si					
Module Area	1.95	m2				
Number of Cells	72					

Table 4: PV Fixed Tilt – Inverter Input Parameters

Inverter: SMA America: SC 500HE-US 200V [CEC 2010]					
Inverter Characteristics					
AC Voltage	200	V	C0	-4.02894e-008	1/W
Power ACo	500,000	Wac	C1	3.10557e-005	1/V
Power DCo	511,510	Wdc	C2	0.00565754	1/V
PowerSo	1,879.21	W	C3	0.000739241	1/V
PowerNTare	101	W	MPPT_low	330	V
Vdcmax	600	V	Vdco	370.784	V
Idcmax	1600	A	MPPT_hi	600	V

Table 5: PV Fixed Tilt – Array Sizing and Losses

Modules per String	12				
Strings in Parallel	352				
Number of Inverters	2				
Actual Layout					
Modules			Inverters		
Nameplate Capacity	1202.62	kWdc	Total Capacity	1000	kWa
Number of Modules	4224		Number of Inverters	2	
Modules per String	12		Vdcmax (dc-inverter)	600	V
Strings in Parallel	352		MPPT_low	330	V
Total Module Area	8236.8	m2	MPPT_hi	600	V
Voc (String)	540	V			
Vmp (String)	426	V			
Interconnection Derates					
AC wiring losses	0.995	(0..1)			
Step-up transformer losses	0.9936	(0..1)			
Total interconnection derate	0.988632	(0..1)			
Tracking and Orientation					
Tracking/Fixed	Fixed				
Tilt (deg)	20				
Azimuth (deg)	180				
Shading and Soiling					
Annual average soiling (0..1)	0.99				
Pre-inverter Derates					
Mismatch (0..1)	0.99				
Diodes and connections (0..1)	1				
DC wiring loss (0..1)	0.985				
Tracking error (0..1)	1				
Nameplate (0..1)	1				
Estimated DC power derate (0..1)	0.97515				

Table 6: PV Fixed Tilt – Degradation

System Output Adjustments		
Percent of annual output	99.03 %	

PV Single-Axis Tracking (SAT)

URS used the same inverter, module, and array size for the PVSAT input parameters as those used in the PVFT model.

Array Orientation

URS used a due south input for the PVSAT array orientation azimuth. URS determined the range of the tracker motion based on a review of current SAT manufacturer specifications (Table 6).

Table 7: PV Single-Axis Tracker – Range of Tracker Motion

	Tilt	Tracking Range of Motion	Tracking Accuracy
ATI DuraTrackHZ	0	+/-45°	+/-2°
PVHardware Axone	0	+/-45°	UA
SPG SunSeeker	0	+/-45°	UA

URS selected a tracking range of +/- 45° due to the prevalence of this range in currently manufactured SAT equipment. URS also specified the use of backtracking and a row width of 1.97m and row-to-row-spacing of 5m. The row width is a typical value for the width of 72 cell solar modules. The row-to-row spacing provides a ground-cover-ratio (GCR) of 40%. This is a common design parameter for utility-scale solar systems, which maximizes the use of the available ground area without causing self-shading.

Table 8: PV Single-Axis Tracker – Array Sizing and Losses

String Configuration	
Strings in array	352
Subarray 1	
Strings allocated to subarray	352
Tracking and Orientation	
Tracking/Orientation	1-Axis
Tilt (deg)	0
Azimuth (deg)	180
Tracker rotation limit (deg)	45
Row width	1.97
Space between edges of adjacent rows (m)	5
Shading and Soiling	
Annual average soiling (0..1)	0.99
Pre-inverter Derates	
Mismatch (0..1)	0.99
Diodes and connections (0..1)	1
DC wiring loss (0..1)	0.985
Tracking error (0..1)	0.98
Nameplate (0..1)	1
Estimated DC power derate (0..1)	0.955647

Residential PV Model (RES)

URS configured the residential model to use Solarworld SW250 Polysilicon modules. These are 62 cell modules, which are a common physical size and power capacity for residential systems. Similarly, URS used the SMA Sunny Boy SB5000US-11 240V inverter due to the quality of products of SMA and its nameplate power rating.

URS specified the same modules per string (12) for the residential model as the PVFT and PVSAT models. The same DC/AC ratio was kept constant across models as well and resulted in 2 strings for a nameplate DC capacity of 6.023 kW.

URS specified the slope of the modules for the RES model as 22.6°, which is equivalent to the common 5/12 roof pitch.

The “percent of annual output” parameter was set to 99.3%, which assumes -0.67% light induced degradation per year for 25 years. This rate of degradation matches the warranty specified by the module manufacturer.

Table 9: PV Residential – Module Input Parameters

Module: SolarWorld SW250 Poly						
Module Characteristics at Reference Conditions						
Efficiency	15.67	%	Temperature Coefficients			
Maximum Power (Pmp)	250.096	Wdc	-4.500e-001	%/C	-1.125e+000	W/C
Max Power Voltage (Vmp)	30.8	Vdc				
Max Power Current (Imp)	8.12	Adc				
Open Circuit Voltage (Voc)	37.6	Vdc	-3.890e-001	%/C	-1.463e-001	V/C
Short Circuit Current (Isc)	8.64	Adc	8.300e-002	%/C	7.171e-003	A/C
Physical Characteristics						
Material	Multi-c-Si					
Module Area	1.596	m2				
Number of Cells	60					

Table 10: PV Residential – Inverter Input Parameters

SMA America: SB5000US-11 240V [CEC 2007]					
Inverter Characteristics					
AC Voltage	240	V	C0	-5.02814e-006	1/W
Power ACo	5000	Wac	C1	6.26654e-005	1/V
Power DCo	5204.6	Wdc	C2	0.00232889	1/V
PowerSo	51.4071	W	C3	0.000450495	1/V
PowerNTare	0.72	W	MPPT_low	250	V
Vdcmax	0	V	Vdco	309.883	V
Idcmax	0	A	MPPT_hi	480	V

Table 11: PV Residential – Array Sizing and Losses

Specify System Size					
Desired Array Size	4	kWdc			
Modules per String	12				
Strings in Parallel	2				
Number of Inverters	1				
Actual Layout					
Modules			Inverters		
Nameplate Capacity	6.0023	kWdc	Total Capacity	5	kWa
Number of Modules	24		Number of Inverters	1	
Modules per String	12		Vdcmax (dc-inverter)	0	V
Strings in Parallel	2		MPPT_low	250	V
Total Module Area	38.304	m2	MPPT_hi	480	V
Voc (String)	451.2	V			
Vmp (String)	369.6	V			
Interconnection Derates (AC)					
AC wiring losses	0.99	(0..1)			
Step-up transformer losses	1	(0..1)			
Total interconnection derate	0.99	(0..1)			
Tracking and Orientation					
Fixed/Tracking	Fixed				
Tilt (deg)	22.6				
Azimuth (deg)	180				
Shading and Soiling					
Annual average soiling (0..1)	0.95				
Pre-inverter Derates					
Mismatch (0..1)	0.99				
Diodes and connections (0..1)	1				
DC wiring loss (0..1)	0.99				
Tracking error (0..1)	1				
Nameplate (0..1)	0.99				
Estimated DC power derate (0..1)	0.970299				

Table 12: PV Residential – Degradation

System Output Adjustments		
Percent of annual output	99.3	%

Concentrating Solar Power (CSP)

Where possible, URS used CSP model input parameters consistent with the design of the SEGSI through SEGSI and the Nevada Solar One plants, which are all parabolic trough systems built in the United States. Appendix III and Appendix IV provide more detailed information about the parameters of these 10 plants.

Solar Field

To develop an input parameter for the field aperture of the parabolic trough collectors URS utilized ratios of design values for the Nevada Solar One (NSO) plant, which is of a similar size and has the same thermal storage capacity, 0.5 hrs, as the URS SAM model.

URS assumed a design irradiation for the Nevada Solar One parabolic trough plant of 950 W/m^2 .

From available data URS calculated the ratio of aperture area to the plant gross MWe for NSO to be $4,762.66 \text{ m}^2/\text{MWe}$. URS selected a design gross capacity for the CSP model of 55MWe, which provides an expected net capacity of 50MWe. The 50MWe value was originally specified as the capacity for concentrating solar power by ERCOT.

URS determined the product of the gross plant capacity for the URS model and the aperture area to plant gross capacity ratio for the NSO plant to be $261,946 \text{ m}^2$. URS used this field aperture as in initial input to the SAM model.

With the design irradiation parameter specified as 950 W/m^2 SAM calculates an actual solar multiple of 1.23002.

URS based some of the inputs for the CSP plant on the assumption that the plant would be located in the El Paso area. This assumption is justified by the increased productivity of CSP plants in areas with strong direct normal irradiation (DNI). The El Paso region has the strongest DNI of the NSRDB weather stations in Texas. The Nevada Solar One plant is near Las Vegas, which has higher DNI for more hours of the year than El Paso. Due to this difference in the solar resource, a CSP plant in El Paso would need a greater ratio of collector area to gross plant capacity. URS accounted for this difference through an analysis of available typical year weather data for Las Vegas and El Paso. In Las Vegas 8% of the hours with measurable DNI have DNI which is equal to or greater than 950 W/m^2 . Using a guess and check methodology the DNI at which 8% of the hours with measurable DNI is equal to or greater than a given value provides a DNI of 927 W/m^2 in El Paso.

Changing the design irradiation parameter in the SAM model to 927 W/m^2 reduces the actual solar multiple to 1.19891. A guess and check process using the SAM field aperture parameter to bring the actual solar multiple back to 1.23317 (as close as SAM would calculate to 1.23002) results in a final field aperture of $269,100 \text{ m}^2$.

Collectors (SCAs) & Receivers (HCEs)

For representative simulation purposes, URS specified the Solargenix SGX-1 as the collector and the Solel UVAC 3 as the receiver. Similar equipment was used for the SEGS and NSO systems.

Power Cycle

URS selected a rated cycle conversion efficiency of 37.6%, which matches the rated efficiency for SEGS VIII and IX. These plants are similar in capacity and design as the modeled plant.

Plant Capacity

URS selected a design gross capacity for the CSP model of 55MWe, which provides an expected net capacity of 50MWe. The 50MWe value was originally specified as the capacity for concentrating solar power by ERCOT. This system size is reasonable for the range of plant sizes that have been designed and constructed in the US, including SEGSI through SEGSIIX and Nevada Solar One (75MWe gross).

URS selected a boiler operating pressure of 100 bar, which is consistent with the SEGS plants.

URS selected an evaporative condenser for the CSP model. This selection matches the type of heat rejection used for the NSO plant. Plants with evaporative heat rejection are more efficient due to the lower condensing temperatures obtainable with evaporative cooling. URS used SAM to generate psychrometric values based on the TMY3 weather file for El Paso. A SAM run was used to create a file containing the hourly DNI and wet bulb temperatures for El Paso. URS used the data in this file to calculate average wet bulb temperatures for hours with DNI equal to or greater than 800 W/m² and 950 W/m². The average of the wet bulb temperatures for these hours were 10.668°C and 7.246°C for the hours with DNI greater than 800W/m² and 950W/m², respectively.

URS selected a design wet bulb temperature for the cooling system of 10.668 due to greater hours of operation, 32% of hours with measurable DNI rather than 5% for the 7.246°C temperature.

Storage system

URS specified 0.5 hours of TES. This value matches the TES capacity of the NSO plant and provides enough storage for transient conditions. SAM calculates the necessary storage volume based on the user input of storage capacity.

SAM calculates the tank diameter, but allows the user to input a value for the tank height. An ideal height to diameter ratio for TES is 1:3. This provides for stratification within the storage tank, but does not sacrifice increase the surface area to volume ratio dramatically. Using this ratio URS calculated a tank height of 23.2m. The SAM calculated tank diameter with this tank height was 7.72977m.

SAM calculates thermal losses from a storage tank based on a tank loss coefficient, the tank volume, and the tank temperature. The tank volume is calculated by SAM and the tank temperature is calculated for each time-step as the simulation runs. URS specified a tank loss coefficient of 1.49 W/m²-K. This value is based on a correlation developed for large storage tank between the tank volume and an optimal insulation thickness.

$$y = 21.404x^{0.3669}$$

This correlation provides the insulation thickness (y,mm) for a given storage volume (x, m³).¹² Using the tank volume of 1088.71m³ the correlation produces an insulation thickness of 278.444mm. Typical insulation for this type of storage tank is calcium silicate block, which has a thermal conductivity of 0.0633 W/mK. URS calculated the tank loss coefficient using this thermal conductivity, the assumption that the storage tank has 7mm thick steel walls, and is exposed to an ambient air temperature of 22°C.

Performance Adjustment

URS estimated the plant would be out of operation for 7 days out of the year. This lack of availability is expressed in the CSP model as a 98.1% system output adjustment.

Table 13: Concentrating Solar Power – Solar Field

Solar Field Parameters		
Field aperture	269100	m2
Row spacing	15	m
Stow angle	170	deg
Deploy angle	10	deg
Irradiation at design	927	W/m2
Heat Transfer Fluid		
Field HTF fluid	Therminol VP-1	
Design loop inlet temp	293	'C
Design loop outlet temp	391	'C
Design Point		
Single loop aperture	3762.4	m2
Loop optical efficiency	0.751213	
Total loop conversion efficiency	0.718323	
Total required aperture, SM=1	219672	m2
Required number of loops, SM=1	58.3862	
Actual number of loops	72	
Total aperture reflective area	270893	m2
Actual solar multiple	1.23317	
Field thermal output	180.384	MWt

Table 14: Concentrating Solar Power – Collectors and Receivers

Collectors (SCAs)	Solargenix SGX-1
Receivers (HCEs)	Solel UVAC 3

¹² A Solar Thermal System With Seasonal Storage for a Net-Zero Energy School, Master's Thesis, Ben Taylor, RPI, 2012.

Table 15: Concentrating Solar Power – Power Cycle

Plant Capacity		
Design gross output	55	MWe
Estimated gross to net conversion factor	0.9	
Estimated net output at design (nameplate)	50	MWe
Power Block Design Point		
Rated cycle conversion efficiency	0.376	
Design inlet temperature	391	°C
Design outlet temperature	293	°C
Boiler operating pressure	100	bar
Steam cycle blowdown fraction	0.02	
Fossil backup boiler LHV efficiency	0.9	
Aux heater outlet set temp	391	°C
Fossil dispatch mode	Minimum backup level	
Cooling System		
Condenser type	Evaporative	
Ambient temp at design	10.668	°C
Ref. Condenser Water dT	10	°C
Approach temperature	5	°C
Cooling system part load levels	2	

Table 16: Concentrating Solar Power – Thermal Storage

Storage System		
Full load hours of TES	0.5	hr
Storage volume	1088.71	m3
TES Thermal capacity	73.1383	MWt
Parallel tank pairs	1	
Tank height	23.2	m
Tank fluid minimum height	1	m
Tank diameter	7.72977	m
Min fluid volume	46.927	m3
Tank loss coefficient	1.49	W/m2-K
Estimated heat loss	0.292815	MWt
Cold tank heater set point	250	'C
Hot tank heater set point	365	'C

Simulation Management and Results Processing

The SamUL scripting language was used to automate the process of running each of the four solar models for the 20 historical year data files for each of the 93 weather stations and the 65 TMY files. Additional post-processing was completed using a Unix Bash shell script and the AWK programming language to prepend the date and time from the input weather file to each output file and to add a column containing the exported energy (kWH-AC), which did not contain negative values (energy consumption by the plant) per ERCOT's request.

See Appendix V for summary graphs showing the 20 years of historical annual electricity production estimates for six representative sites across Texas. To facilitate comparison between the different solar models URS linearly scaled the results of the PVSAT, PVFT, and RES models shown in Appendix V to the equivalent output of a 50MW-AC solar plant.

4: Statistical Analysis of Data

P50/P90 Exceedance Probabilities

The likelihood that a solar array will generate a certain amount of electricity in any given year over the facility's expected life can be determined using statistical analysis of solar radiation and meteorological data. Interannual solar resource variability can be quantified by calculating the exceedance probabilities representing the amount of energy expected to be produced by a solar generation facility. An exceedance probability is the probability that a certain value will be exceeded. For example, a P50 value of 100,000 kWh for the annual output of a solar array means that there is a 50% likelihood that the system's annual output will be greater than 100,000 kWh. A P90 value of 100,000 kWh indicates that there is a 90% likelihood that the system's annual output will be greater than 100,000 kWh.

URS calculated the exceedance probabilities for six of the 34 weather stations included in this analysis. The six weather stations selected represent different areas of the state to highlight regional differences in magnitude and variability of annual electricity production. URS calculated the P50 and P90 values for each of the six stations (see Figure 5) by generating cumulative distribution functions (CDF) from both the normal distribution of the dataset using the mean and standard deviation of the values and from the empirical data (see Figure 6). URS then determined the P50 and P90 exceedance probabilities either directly from the normal CDF equation or by linearly interpolating the empirical CDF table.

The CDF graphs in Figure 6 demonstrate the differences in magnitude and variability of the annual electricity output for a 1MW fixed tilt PV system located in the area of influence of the respective station.

Figure 5: Min, P90, P50, and Max of Annual Output, PV Fixed Tilt

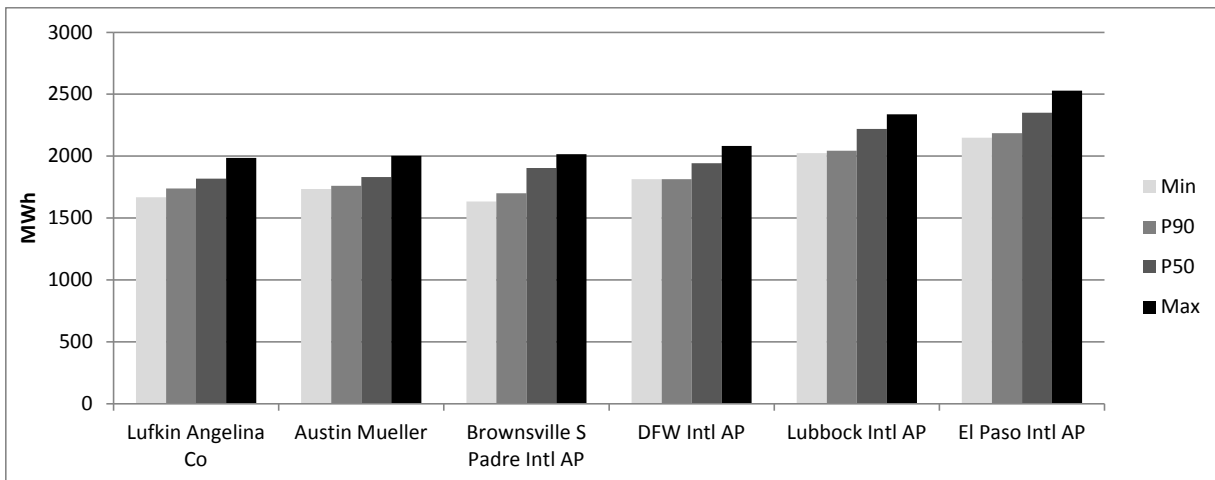
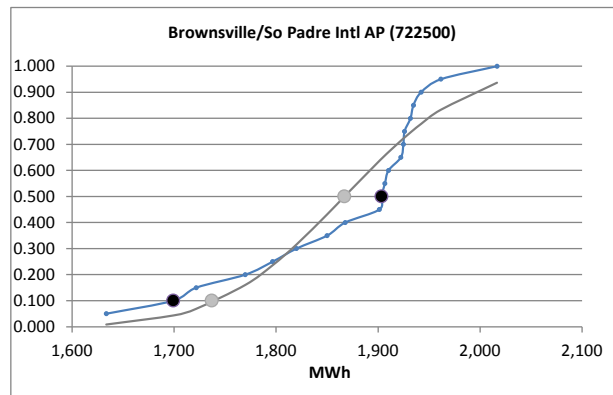
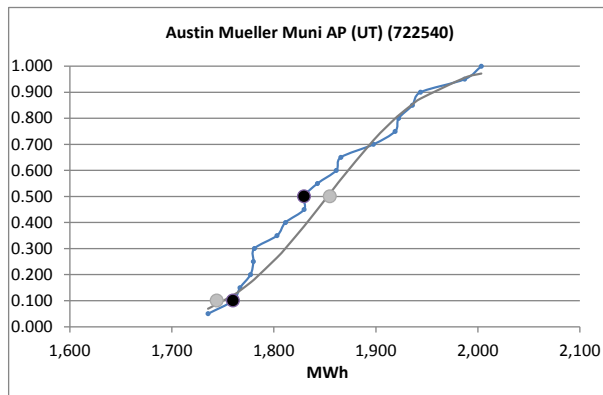
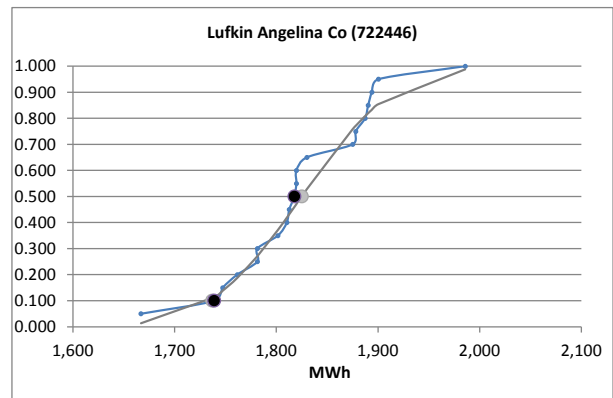
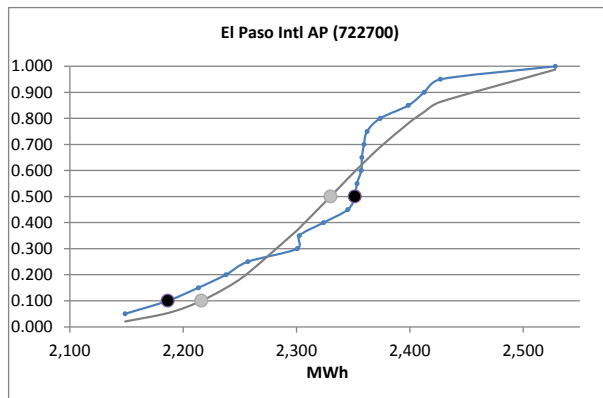
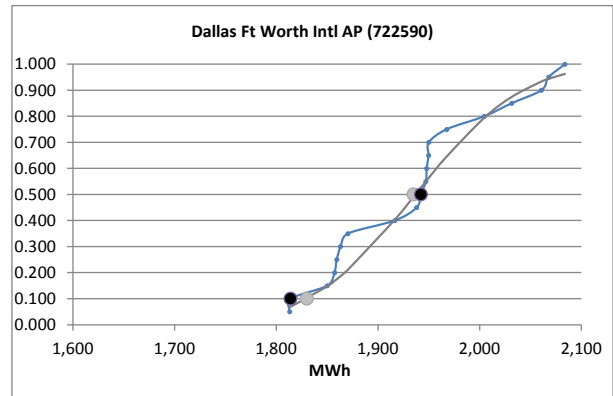
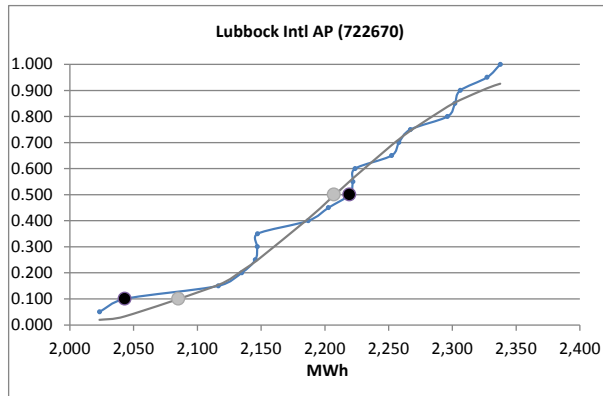


Figure 6: Cumulative Distribution Functions of Annual AC Output, PV Fixed Tilt

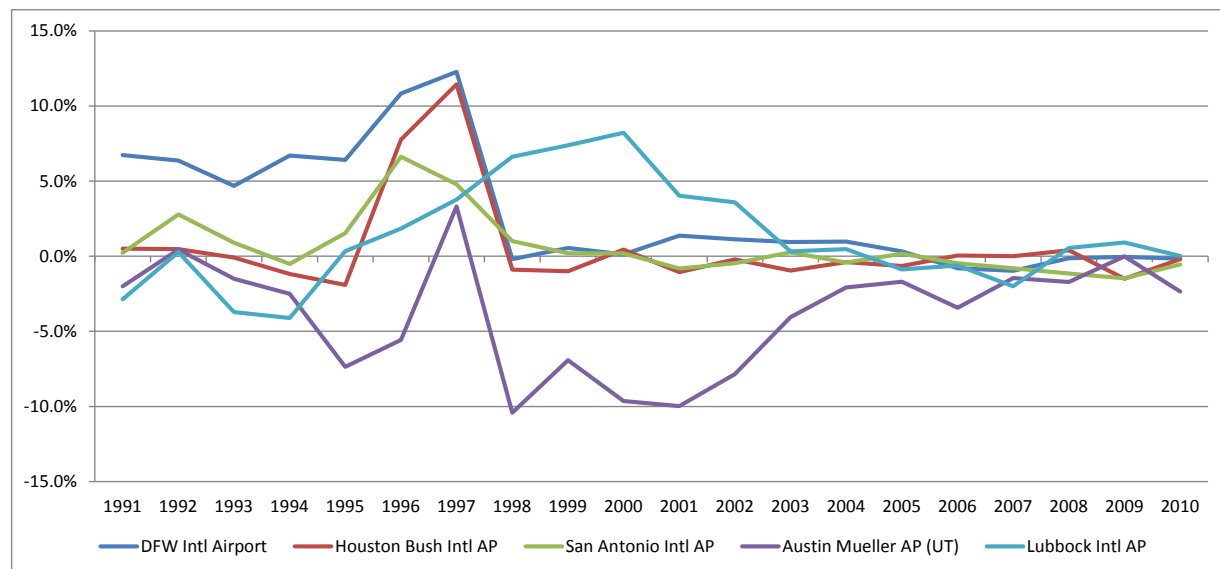


	Empirical CDF
	Normal Dist. CDF
	Empirical P50/P90
	Normal Dist. P50/P90

Variance Analysis of Nearby Weather Stations

URS conducted a comparison of the production model results generated from the Class I weather stations used in this analysis with nearby weather stations that were not used due to redundancy in geographic coverage. This comparison uses five Class I weather stations located at airports in major metropolitan areas (Dallas/Ft. Worth, Houston, Austin, San Antonio, and Lubbock) and compares the 20-year annual production values with the same model results from nearby weather stations (see Figure 7). The objective of this analysis is to understand the magnitude and trends of potential variances in the data across different regions of the state.

Figure 7: Weather Station Variance Analysis Results



The Y axis in Figure 7 is the percent variance between the annual production model results for the selected Class I weather station and a nearby weather station that was not used in the analysis (see Figure 8 for the names/locations of comparison stations). The decreasing variability between stations after 1998 is most likely due to the introduction of satellite imagery data in the model used to produce the NSRDB data. Satellite imagery data was not available for the time period of 1991-1997. Many Class II weather stations relied upon inferior statistically derived cloud cover data prior to 1998. As described in the NSRDB User's Manual, the algorithm used to distinguish between Class I and Class II weather stations measures the uncertainty for each hourly modeled value in the global field. If less than 25% of the data for the period of record exceeds an uncertainty of 11%, the station receives a Class I designation. Otherwise, it receives a Class II designation. Uncertainty calculations performed by NREL validate that the 11% uncertainty threshold discriminates between the data modeled with good human-observed or satellite-derived cloud cover and the filled or statistically derived cloud cover.

Figure 8: Weather Station Variance Analysis Data

Weather Station	DFW Intl Airport	Dallas Addison Arpt	
ID #	722590	722598	
Class	1	2	% Variance
1991	1,814,041	1,692,024	6.7%
1992	1,813,117	1,697,642	6.4%
1993	1,870,325	1,782,809	4.7%
1994	1,857,171	1,732,614	6.7%
1995	1,947,855	1,823,023	6.4%
1996	2,067,839	1,843,747	10.8%
1997	1,863,155	1,634,368	12.3%
1998	1,949,608	1,953,371	-0.2%
1999	2,060,615	2,049,399	0.5%
2000	1,949,967	1,947,559	0.1%
2001	1,937,965	1,911,484	1.4%
2002	1,942,135	1,920,289	1.1%
2003	1,947,011	1,928,683	0.9%
2004	1,850,065	1,831,981	1.0%
2005	2,004,435	1,998,134	0.3%
2006	2,083,696	2,100,418	-0.8%
2007	1,859,378	1,877,354	-1.0%
2008	2,031,400	2,034,222	-0.1%
2009	1,916,381	1,917,358	-0.1%
2010	1,967,426	1,970,800	-0.2%

Weather Station	Houston Bush Intl AP	Houston DW Hooks	
ID #	722430	722429	
Class	1	2	% Variance
1991	1,616,428	1,608,179	0.5%
1992	1,692,978	1,684,981	0.5%
1993	1,743,682	1,745,297	-0.1%
1994	1,688,447	1,708,408	-1.2%
1995	1,794,178	1,828,535	-1.9%
1996	1,744,967	1,609,550	7.8%
1997	1,594,154	1,411,823	11.4%
1998	1,806,399	1,822,671	-0.9%
1999	1,919,035	1,938,089	-1.0%
2000	1,871,106	1,862,687	0.4%
2001	1,794,828	1,813,760	-1.1%
2002	1,795,887	1,799,642	-0.2%
2003	1,769,443	1,786,360	-1.0%
2004	1,739,574	1,746,477	-0.4%
2005	1,903,182	1,915,520	-0.6%
2006	1,843,595	1,842,822	0.0%
2007	1,770,694	1,770,721	0.0%
2008	1,861,349	1,854,082	0.4%
2009	1,772,273	1,798,931	-1.5%
2010	1,836,895	1,840,486	-0.2%

Weather Station	San Antonio Intl AP	San Antonio Kelly AFB	
ID #	722530	722535	
Class	1	2	% Variance
1991	1711322.754	1707389.88	0.2%
1992	1772861.634	1723579.829	2.8%
1993	1788471.714	1772462.838	0.9%
1994	1753031.83	1762159.562	-0.5%
1995	1910030.913	1880595.483	1.5%
1996	2018121.524	1884467.198	6.6%
1997	1836137.072	1748391.946	4.8%
1998	1928321.968	1908962.325	1.0%
1999	1993075.774	1989228.01	0.2%
2000	1897997.874	1894378.418	0.2%
2001	1878452.186	1893904.456	-0.8%
2002	1893135.026	1901879.898	-0.5%
2003	1838930.552	1834214.885	0.3%
2004	1769725.839	1777110.418	-0.4%
2005	1917752.419	1914479.178	0.2%
2006	1942125.533	1951110.874	-0.5%
2007	1787732.497	1802080.599	-0.8%
2008	1937849.395	1960296.928	-1.2%
2009	1906998.203	1934914.536	-1.5%
2010	1933926.518	1944369.765	-0.5%

Weather Station	Austin Mueller AP (UT)	Ft Hood	
ID #	722540	722570	
Class	1	2	% Variance
1991	1759842.455	1795106.947	-2.0%
1992	1842753.696	1834657.574	0.4%
1993	1865556.422	1893647.359	-1.5%
1994	1811309.154	1856785.598	-2.5%
1995	1803045.311	1935709.392	-7.4%
1996	1829658.037	1931513.358	-5.6%
1997	1897570.124	1834816.105	3.3%
1998	1766848.618	1950836.122	-10.4%
1999	1918808.856	2051756.653	-6.9%
2000	1779958.509	1951681.229	-9.6%
2001	1735448.253	1908686.03	-10.0%
2002	1780864.463	1920551.569	-7.8%
2003	1861122.595	1936426.404	-4.0%
2004	1777056.936	1813875.902	-2.1%
2005	1943621.992	1976559.893	-1.7%
2006	2003338.778	2072177.263	-3.4%
2007	1829567.57	1856255.451	-1.5%
2008	1986941.188	2020863.831	-1.7%
2009	1922315.339	1922485.899	0.0%
2010	1935697.131	1981361.939	-2.4%

Weather Station	Lubbock Intl AP	Amarillo Intl AP	
ID #	722670	723630	
Class	1	1	% Variance
1991	2023217.81	2081342.722	-2.9%
1992	2043075.822	2037539.705	0.3%
1993	2116353.447	2195072.466	-3.7%
1994	2145446.741	2233611.783	-4.1%
1995	2147152.555	2139805.708	0.3%
1996	2337498.497	2294628.607	1.8%
1997	2134710.534	2054303.875	3.8%
1998	2306136.21	2153213.463	6.6%
1999	2296080.349	2126558.941	7.4%
2000	2252224.616	2067266.726	8.2%
2001	2221911.509	2132464.231	4.0%
2002	2223634.314	2143930.092	3.6%
2003	2301951.149	2294477.369	0.3%
2004	2146929.172	2136655.829	0.5%
2005	2219259.971	2238616.024	-0.9%
2006	2267023.482	2280984.14	-0.6%
2007	2186870.031	2230798.281	-2.0%
2008	2327046.304	2314365.552	0.5%
2009	2258052.729	2237281.387	0.9%
2010	2202765.681	2202541.856	0.0%

Appendix I: NSRDB to TMY3 Data Conversion Field Label Summary

NSRDB FIELD NAME	YYY-MM-DD	HH:MM (LST)	ETR (Wh/m ²)	ETR (Wh/m ²)	ETR (Wh/m ²)	Meas Glo (Wh/m ²) OR GHI (W/m ²)	Glo Mod Source	Glo Mod Unc (%) OR FILLED GHI uncert (%)
TMY3 FIELD NAME	Date (MM/DD/YYYY)	Time (HH:MM)	ETR (W/m ²)	ETR (W/m ²)	ETR (W/m ²)	GHI (W/m ²)	GHI source	
NSRDB FIELD NAME	Dir Mod (Wh/m ²) OR Meas Dir (Wh/m ²)	Dir Mod Source	Dir Mod Unc (%) OR FILLED	DifMod (Wh/m ²)	DifMod Source	DifMod Unc (%) OR FILLED		
TMY3 FIELD NAME	DNI (W/m ²)	DNI source	DNI uncert (%)	DHI (W/m ²)	DHI source	DHI uncert (%)		GH illum (lx)
NSRDB FIELD NAME	ABSENT	ABSENT	ABSENT	ABSENT	ABSENT	ABSENT		
TMY3 FIELD NAME	GH illum source	Global illum uncert (%)	DN illum (lx)	DN illum source	DN illum uncert (%)	DN illum (lx)		
NSRDB FIELD NAME	ABSENT	ABSENT	ABSENT	ABSENT	ABSENT	TotCC (10ths)		
TMY3 FIELD NAME	DH illum source	DH illum uncert (%)	Zenith lum (cd/m ²)	Zenith lum source	Zenith lum uncert (%)	TotCld (tenths)		
NSRDB FIELD NAME	TotCC Flg	ABSENT	OpqCC (10ths)	OpqCC Flg	ABSENT	Dry Bulb (C)		
TMY3 FIELD NAME	TotCld source	TotCld uncert (code)	OpqCld (tenths)	OpqCld source	OpqCld uncert (code)	Dry-bulb (C)		
NSRDB FIELD NAME	Dry Bulb Flg	ABSENT	Dew Pnt (C)	Dew Pnt Flg	ABSENT	Rel Hum (%)		
TMY3 FIELD NAME	Dry-bulb source	Dry-bulb uncert (code)	Dew-point (C)	Dew-point source	Dew-point uncert (code)	RHum (%)		
NSRDB FIELD NAME	Rel Hum Flg	ABSENT	Baro Press (mbar)	Baro Press Flg	ABSENT	Wind Dir (deg)		
TMY3 FIELD NAME	RHum source	RHum uncert (code)	Pressure (mbar)	Pressure source	Pressure uncert (code)	Wdir (degrees)		
NSRDB FIELD NAME	Wind Dir Flg	ABSENT	Wind Speed (m/s)	Wind Speed Flg	ABSENT	Hor Vis (m)		
TMY3 FIELD NAME	Wdir source	Wdir uncert (code)	Wspd (m/s)	Wspd source	Wspd uncert (code)	Hvis (m)		
NSRDB FIELD NAME	Hor Vis Flg	ABSENT	Ceil Hgt (m)	Ceil Hgt Flg	ABSENT	Precip Wat (cm)		
TMY3 FIELD NAME	Hvis source	Hvis uncert (code)	CeilHgt (m)	CeilHgt source	CeilHgt uncert (code)	Pwat (cm)		
NSRDB FIELD NAME	Precip Wat Flg	ABSENT	AOD (unitless)	AOD Flg	ABSENT	ABSENT		
TMY3 FIELD NAME	Pwat source	Pwat uncert (code)	AOD (unitless)	AOD source	AOD uncert (code)	Alb (unitless)		
NSRDB FIELD NAME	ABSENT	ABSENT	Liq Precip Depth (mm)	Liq Precip Quantity (hr)	Liq Precip Depth Flg	ABSENT		
TMY3 FIELD NAME	Alb source	Alb uncert (code)	Lprecip depth (mm)	Lprecip quantity (hr)	Lprecip source	Lprecip uncert (code)		

Appendix II: Weather Station-County Groupings

Weather Station #	722410	722420	722430	722445	722446	722448	722470
Weather Station Name	PORT ARTHUR JEFFERSON COUNTY	GALVESTON/ SCHOLLES	HOUSTON BUSH INTERCONTINENTAL	COLLEGE STATION EASTERWOOD FL	LUFKIN ANGELINA CO	TYLER/ POUNDS FLD	LONGVIEW GREGG COUNTY AP [OVERTON - UT]
Class	1	2	1	2	1	2	2
TX County Name(s)	Chambers Hardin Jefferson Orange	Galveston	Austin Brazoria Fort Bend Grimes Harris Liberty Montgomery San Jacinto Waller Washington	Brazos Burleson Robertson	Anderson Angelina Cherokee Freestone Houston Jasper Leon Madison Nacogdoches Newton Polk Sabine San Augustine Trinity Tyler Walker	Henderson Smith Wood	Rusk

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Weather Station #	722480	722500	722505	722506	722510	722516	722526
Weather Station Name	SHREVEPORT REGIONAL ARPT	BROWNSVILLE S PADRE ISL INTL	HARLINGEN RIO GRANDE VALLEY I	MCALLEN MILLER INTL AP [EDINBURG - UT]	CORPUS CHRISTI INTL ARPT [UT]	KINGSVILLE	COTULLA FAA AP
Class	1	1	2	2	1	2	2
TX County Name(s)	Camp	Cameron	Kenedy	Hidalgo	Aransas	Kleberg	Dimmit
	Cass		Willacy	Jim Hogg	Bee		LaSalle
	Franklin			Starr	Brooks		Webb
	Gregg			Zapata	Duval		
	Harrison				Jim Wells		
	Marion				Live Oak		
	Morris				McMullen		
	Panola				Nueces		
	Shelby				Refugio		
	Titus				San Patricio		
	Upshur						

Weather Station #	722530	722540	722550	722555	722560	722590	722597
Weather Station Name	SAN ANTONIO INTL AP	AUSTIN MUELLER MUNICIPAL AP [UT]	VICTORIA REGIONAL AP	PALACIOS MUNICIPAL AP	WACO REGIONAL AP	DALLAS-FORT WORTH INTL AP	MINERAL WELLS MUNICIPAL AP
Class	1	1	1	2	1	1	2
TX County Name(s)	Atascosa Bandera Bexar Comal Frio Gillespie Guadalupe Kendall Kerr Maverick Medina Uvalde Wilson Zavala	Bastrop Bell Blanco Burnet Caldwell Coryell Falls Fayette Hays Lampasas Lee Llano Milam Travis Williamson	Calhoun Colorado Dewitt Goliad Gonzales Jackson Karnes Lavaca Victoria Wharton	Matagorda	Bosque Limestone McLennan	Collin Cooke Dallas Delta Denton Ellis Fannin Grayson Hill Hood Hopkins Hunt Jack Johnson Kaufman Lamar Montague Navarro Rains Rockwall Tarrant Van Zandt Wise	Archer Clay Erath Hamilton Palo Pinto Parker Somervell

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Weather Station #	722615	722630	722636	722650	722656	722660	722670
Weather Station Name	DEL RIO LAUGHLIN AFB	SAN ANGELO MATHIS FIELD	DALHART MUNICIPAL AP	MIDLAND INTERNATIONAL AP	WINK WINKLER COUNTY AP	ABILENE REGIONAL AP [UT]	LUBBOCK INTERNATIONAL AP
Class	2	1	2	1	2	1	1
TX County Name(s)	Kinney	Coke	Carson	Andrews	Loving	Baylor	Armstrong
	Val Verde	Concho	Dallam	Borden	Winkler	Brown	Bailey
		Crockett	Hansford	Brewster		Callahan	Briscoe
		Edwards	Hartley	Crane		Coleman	Castro
		Irion	Hutchinson	Dawson		Comanche	Cochran
		Kimble	Moore	Ector		Eastland	Crosby
		Mason	Oldham	Gaines		Fisher	Deaf Smith
		McCulloch	Potter	Glasscock		Haskell	Dickens
		Menard	Sherman	Howard		Jones	Floyd
		Mitchell		Martin		King	Garza
		Real		Midland		Knox	Hale
		Runnels		Pecos		Mills	Hockley
		Schleicher		Reagan		Nolan	Kent
		Sterling		Reeves		San Saba	Lamb
		Sutton		Terrell		Scurry	Lubbock
		Tom Green		Upton		Shackelford	Lynn
				Ward		Stephens	Motley
						Stonewall	Parmer
						Taylor	Randall
						Throckmorton	Swisher
						Young	Terry
							Yoakum

Weather Station #	722700	723418	723510	723520	723527	723604
Weather Station Name	EL PASO INTERNATIONAL AP [UT]	TEXARKANA WEBB FIELD	WICHITA FALLS MUNICIPAL ARPT	ALTUS AFB	GAGE AIRPORT	CHILDRESS MUNICIPAL AP
Class	1	2	2	2	2	2
TX County Name(s)	Culberson	Bowie	Wichita	Hardeman	Hemphill	Childress
	El Paso	Red River		Wilbarger	Lipscomb	Collingsworth
	Hudspeth				Ochiltree	Cottle
	Jeff Davis				Roberts	Donley
	Presidio				Wheeler	Foard
						Gray
						Hall

Appendix III: Installation Details of Existing Parabolic Trough CSP Plants in US

Plant Name	SEG5 I	SEG5 II	SEG5 III	SEG5 IV	SEG5 V	SEG5 VI	SEG5 VII	SEG5 VIII	SEG5 IX	NSO
Location	Daggett, CA	Daggett, CA	Kramer Junction, CA	Kramer Junction, CA	Kramer Junction, CA	Kramer Junction, CA	Kramer Junction, CA	Harper Lake, CA	Harper Lake, CA	
Start Year	1985	1986	1987	1987	1988	1989	1989	1990	1991	2007
Participants	Luz	Luz	Luz	Luz	Luz	Luz	Luz	Luz	Luz	Acciona Solar Power
Owner(s) (%)	Cogentrix (100%)	Cogentrix (100%)	NextEra (50%)	NextEra (38%)	NextEra (46%)	NextEra (41%)	NextEra (50%)	NextEra (50%)	NextEra (50%)	Acciona Energia (100%)
Operator(s)	Cogentrix	Cogentrix	NextEra	NextEra	NextEra	NextEra	NextEra	NextEra	NextEra	Acciona Solar Power
Generation Offtaker(s)	Southern California Edison	Southern California Edison	Southern California Edison	Southern California Edison	Southern California Edison	Southern California Edison	Southern California Edison	Southern California Edison	Southern California Edison	NV Energy
Plant Configuration										
Solar Field										
Solar-Field Aperture Area:	82,960 m ²	190,338 m ²	230,300 m ²	230,300 m ²	250,500 m ²	388,000 m ²	194,280 m ²	464,340 m ²	483,960 m ²	357,200 m ²
SCA Manufacturer	Luz (LS-1)	Luz (LS-1)	Luz (LS-2)	Luz (LS-2)	Luz (LS-2)	Luz (LS-2)	Luz (LS-2)	Luz (LS-3)	Luz (LS-3)	Acciona Solar Power (SG&2)
SCA Description:	Parabolic trough SCA	Parabolic trough SCA	Parabolic trough SCA	Parabolic trough SCA	Parabolic trough SCA	Parabolic trough SCA	Parabolic trough SCA	Parabolic trough SCA	Parabolic trough SCA	
Solar-Field Outlet Temp:	307°C	316°C	349°C	349°C	349°C	390°C	390°C	390°C	390°C	393°C
Power Block										
Turbine Capacity (Gross):	13.8 MW	30.0 MW	30.0 MW	30.0 MW	30.0 MW	30.0 MW	30.0 MW	89.0 MW	89.0 MW	75.0 MW
Turbine Capacity (Net):	13.8 MW	30.0 MW	30.0 MW	30.0 MW	30.0 MW	30.0 MW	30.0 MW	80.0 MW	80.0 MW	72.0 MW
Output Type:	MHI regenerative steam turbine	MHI regenerative steam turbine, solar preheat and steam generation, natural-gas-fired superheater	MHI regenerative steam turbine, solar preheat and steam generation, natural-gas-fired superheater	MHI regenerative steam turbine, solar preheat and steam generation, natural-gas-fired superheater	MHI regenerative steam turbine, solar preheat and steam generation, natural-gas-fired superheater	MHI regenerative steam turbine, solar preheat and steam generation, natural-gas-fired superheater	MHI regenerative steam turbine, solar preheat and steam generation, natural-gas-fired superheater	MHI regenerative steam turbine, solar preheat and steam generation, natural-gas-fired superheater	MHI regenerative steam turbine, solar preheat and steam generation, natural-gas-fired superheater	
Power Cycle Pressure:	40.0 bar	40.0 bar	40.0 bar	40.0 bar	40.0 bar	100.0 bar	100.0 bar	100.0 bar	40.0 bar	
Turbine Efficiency:	31.5% @ full load	29.4% @ full load	30.6% @ full load	30.6% @ full load	30.6% @ full load	37.5% @ full load	37.5% @ full load	37.6% @ full load	37.6% @ full load	
Fossil Backup Type:	None	Natural gas	Natural gas	Natural gas	Natural gas	Natural gas	Natural gas	Natural gas	Natural gas	
Thermal Storage:										
Storage Type:	2-tank direct									
Storage Capacity:	3 hour(s)									0.5 hour(s)
Thermal Storage Description:	Storage system was damaged by fire in 1995 and was not replaced									0.5 hours full-load storage
HCE Manufacturer										Schott/Solel
(Model):			Solel Solar Systems (Solel UVAC)	Solel Solar Systems (Solel UVAC)	Solel Solar Systems (Solel UVAC)	Solel Solar Systems (Solel UVAC)	Solel Solar Systems (Solel UVAC)	Solel Solar Systems (Solel UVAC)	Solel Solar Systems (Solel UVAC)	
HCE Type (Length):			Evacuated (4 m)	Evacuated (4 m)	Evacuated (4 m)	Evacuated (4 m)	Evacuated (4 m)	Evacuated (4 m)	Evacuated (4 m)	
Heat-Transfer Fluid Type:			Therminol	Therminol	Therminol	Therminol	Therminol	Therminol	Therminol	DOWTHERM A
										Dow Chemical
										# of Solar Collector Assemblies (SCAs):
										760
										# of SCAs per Loop:
										8
										SCA Aperture Area:
										470 m ²
										SCA Length:
										100 m
										Mirror Manufacturer:
										Flabeg
										# of Heat Collector Elements (HCEs):
										18240
										Solar-Field Inlet Temp:
										318°C
										Solar-Field Temp Difference:
										75°C
										Wet cooling
										Lauren Engineering
Land Area:										400 acres
Solar Resource:										2,725 kWh/m ² /yr
Source of Solar Resource:										National Solar Resource Data Base
Electricity Generation:										2,725 kWh/m ² /yr
										National Solar Resource Data Base
										134,000 MWh/yr (Expected/Planned)

Data compiled from http://www.nrel.gov/csp/solarpaces/by_project.cfm

Appendix IV: Summary of Existing Parabolic Trough CSP Plants in US

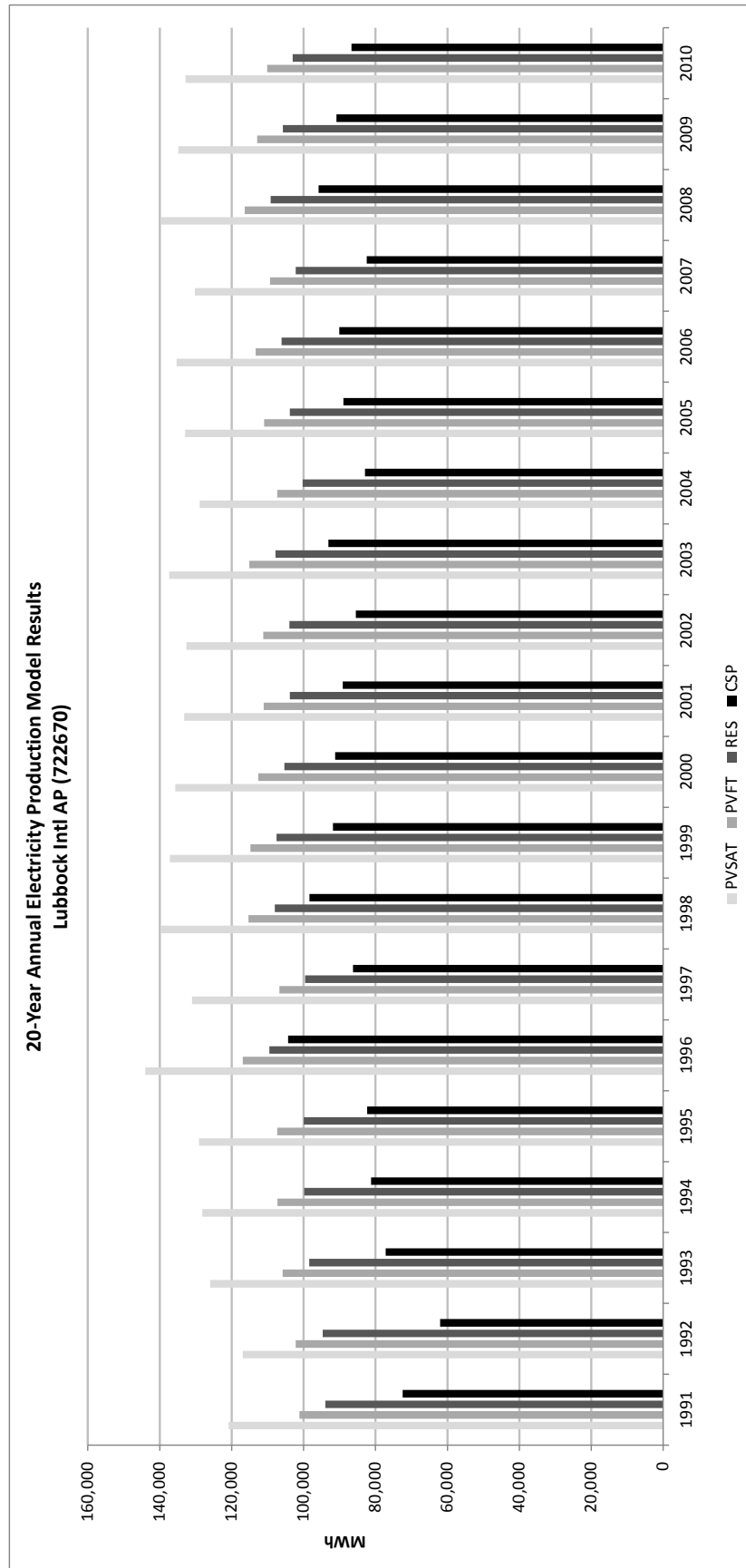
Plant Name	Location	First year of Operation	Net Output (MWe)	Solar Field Outlet (°C)	Solar Field Area (m ²)	Solar Turbine Effic. (%)	Power Cycle	Dispatchability Provided By
Nevada Solar One	Boulder City, NV	2007	72*	390	357200	37.6	100 bar, reheat	None
APS Saguaro	Tucson, AZ	2006	1	300	10340	20.7	ORC	None
SEGS IX	Harper Lake, CA	1991	80	390	483960	37.6	100 bar, reheat	HTF heater
SEGS VIII	Harper Lake, CA	1990	80	390	464340	37.6	100 bar, reheat	HTF heater
SEGS VI	Kramer Junction, CA	1989	30	390	188000	37.5	100 bar, reheat	Gas boiler
SEGS VII	Kramer Junction, CA	1989	30	390	194280	37.5	100 bar, reheat	Gas boiler
SEGS V	Kramer Junction, CA	1988	30	349	250500	30.6	40 bar, steam	Gas boiler
SEGS III	Kramer Junction, CA	1987	30	349	230300	30.6	40 bar, steam	Gas boiler
SEGS IV	Kramer Junction, CA	1987	30	349	230300	30.6	40 bar, steam	Gas boiler
SEGS II	Daggett, CA	1986	30	316	190338	29.4	40 bar, steam	Gas boiler
SEGS I	Daggett, CA	1985	13.8	307	82960	31.5	40 bar, steam	3-hrs TES

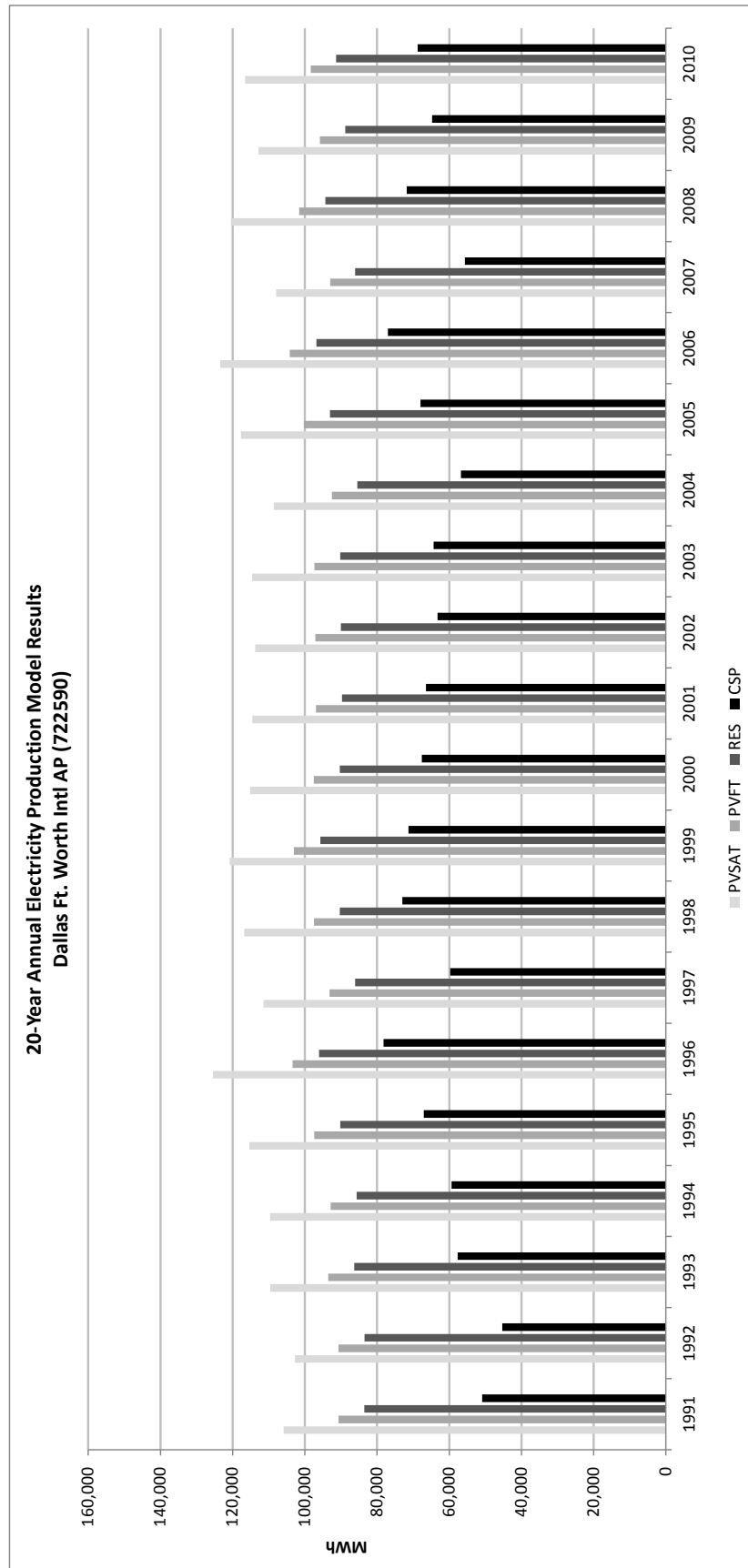
http://www.nrel.gov/csp/troughnet/power_plant_data.html

*Net output updated based on data from: http://www.nrel.gov/csp/solarpaces/by_project.cfm

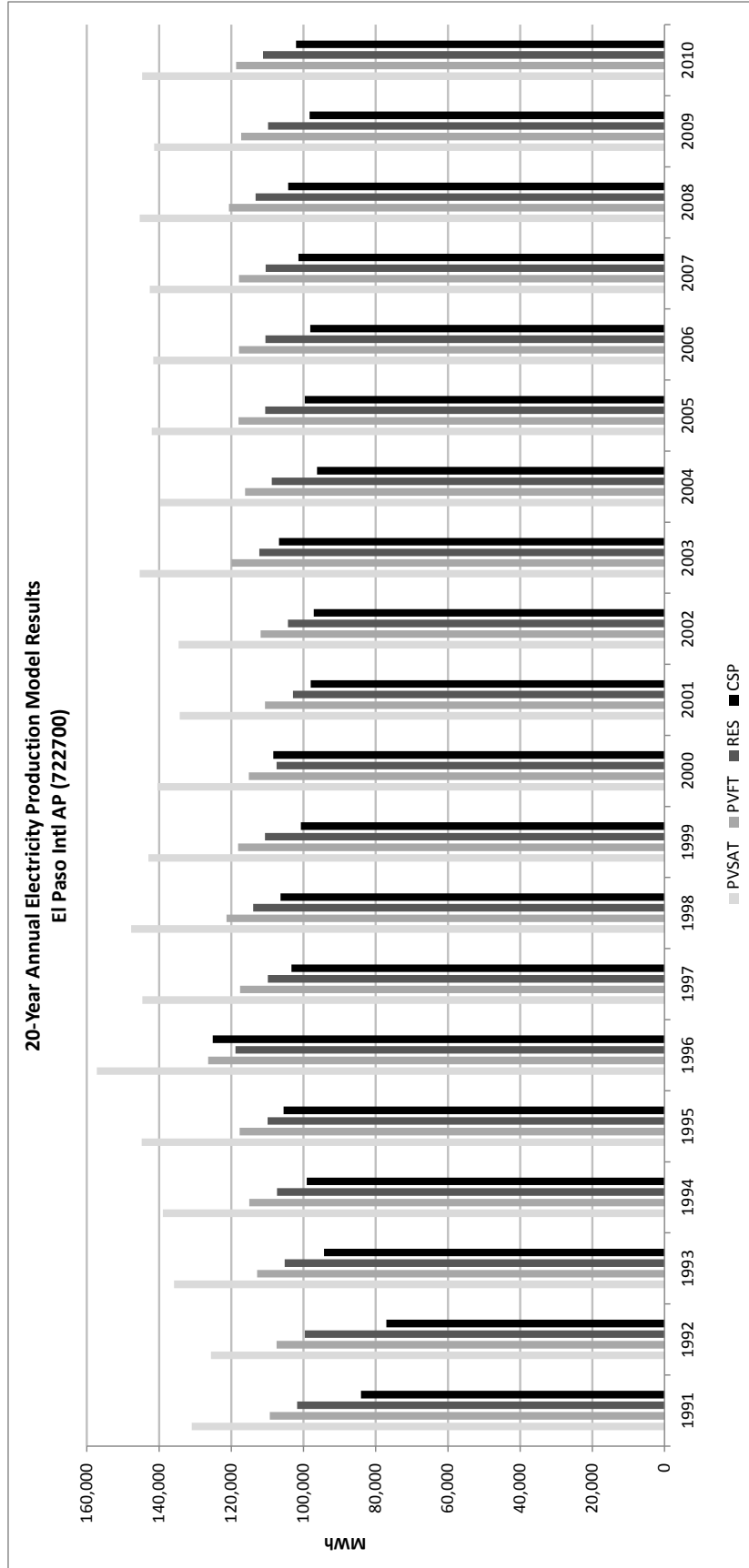
Appendix V: 20-Year Solar Production Estimates

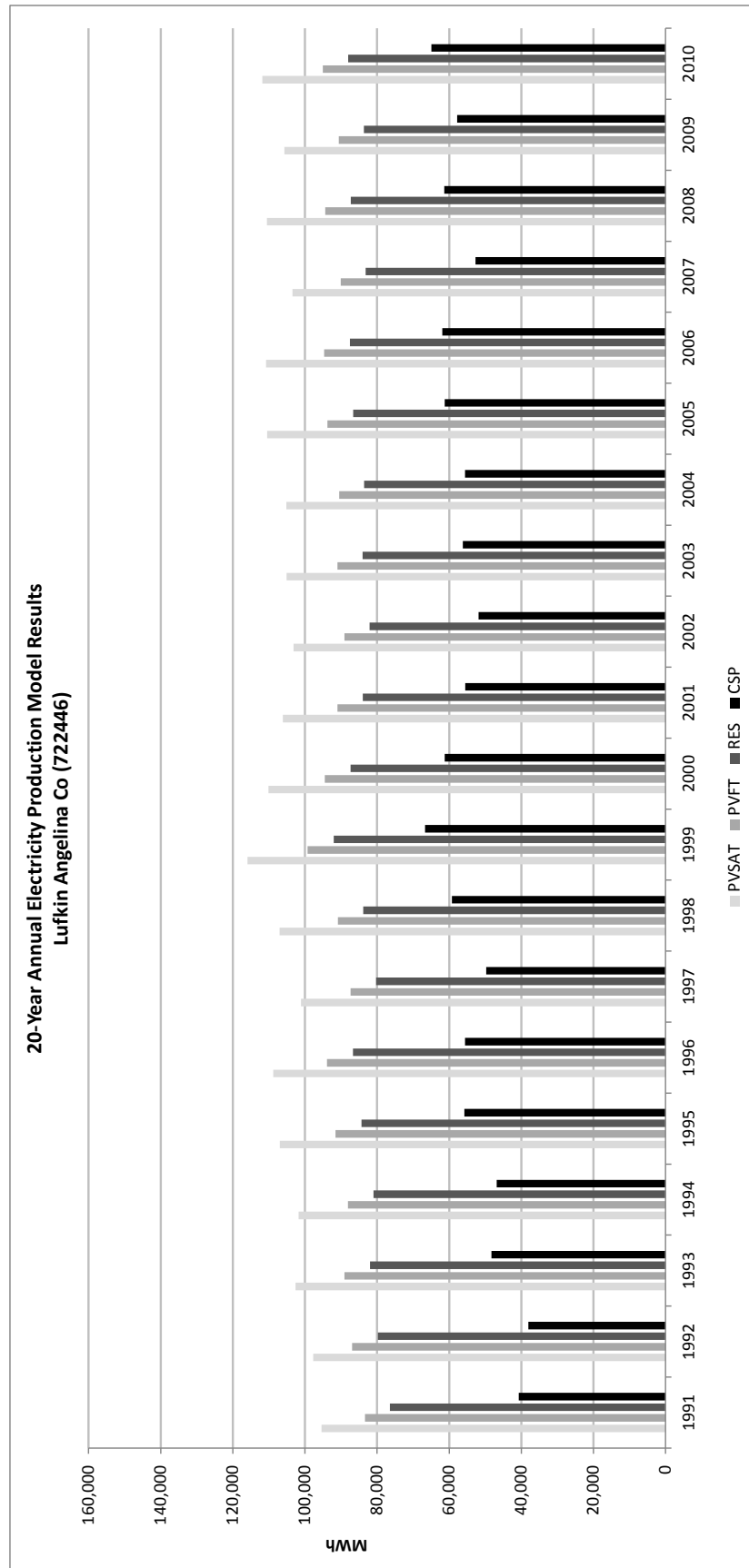
(PRODUCTION VALUES NORMALIZED TO 50-MW EQUIVALENT)

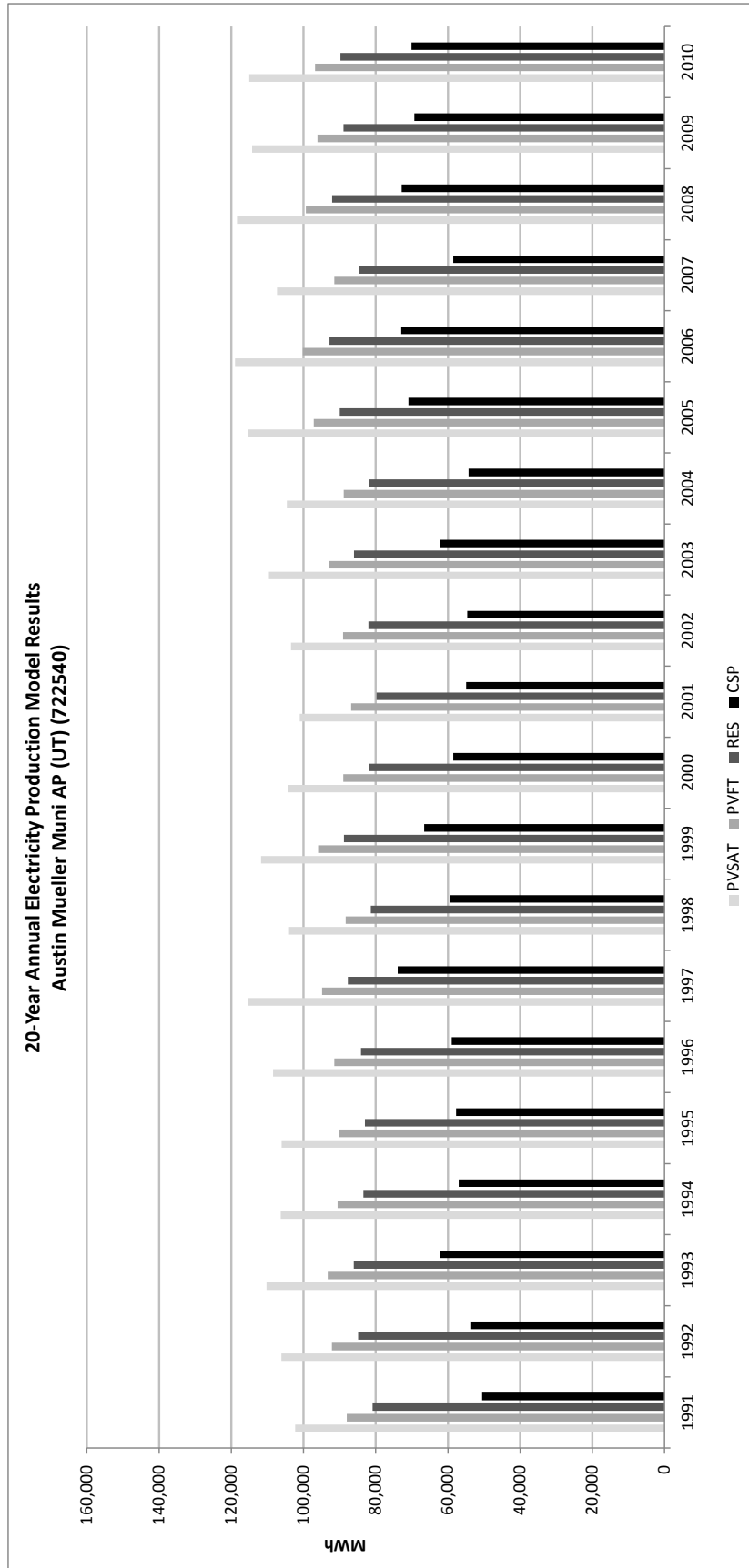


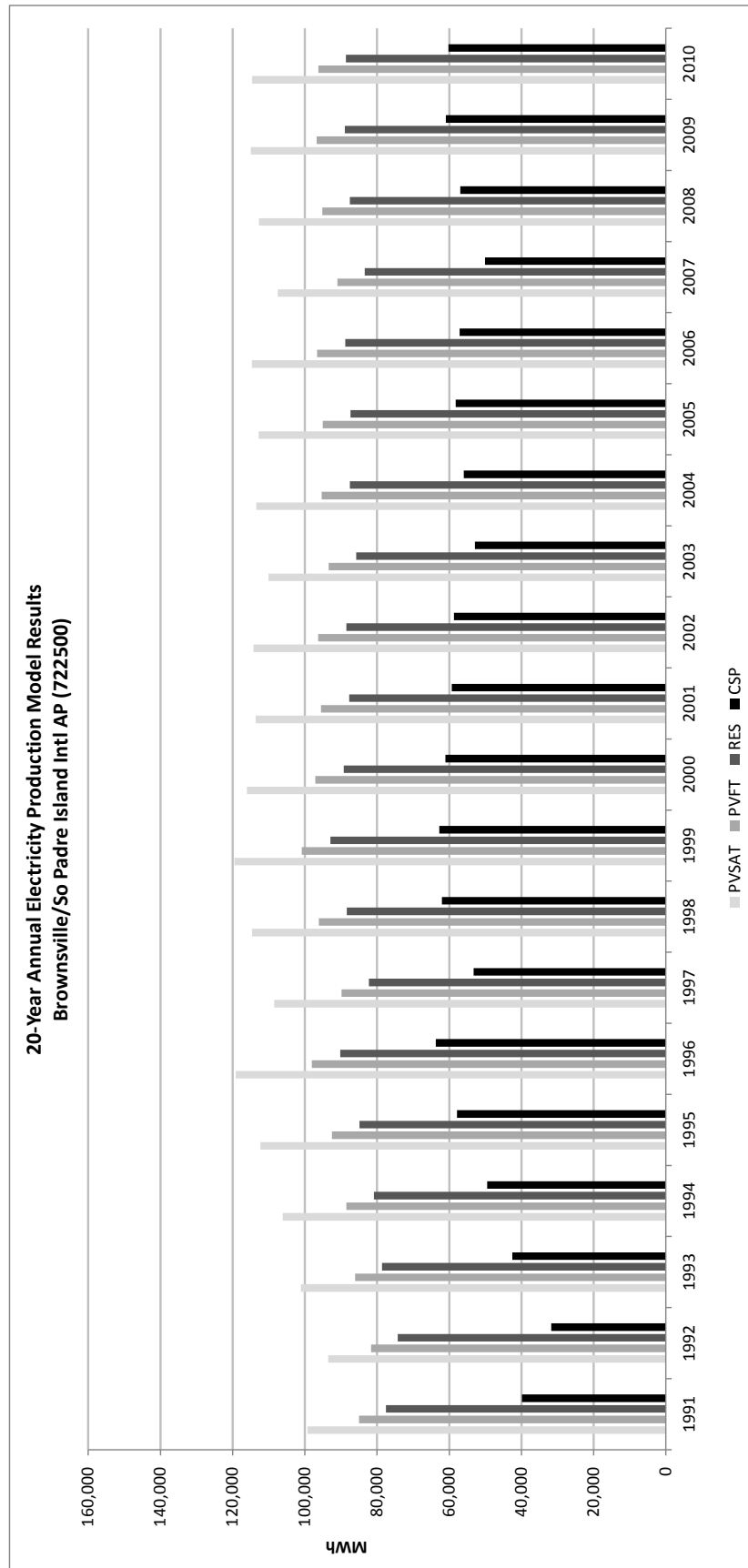


ERCOT Solar Generation Patterns
Project Summary Report










**Appendix T Simulation of Wind Generation Patterns
for the ERCOT Service Area**

**Simulation of Wind Generation Patterns for the ERCOT Service Area
AWS Truepower Report to ERCOT**

PREPARED FOR
ELECTRIC RELIABILITY COUNCIL OF TEXAS

A dark blue world map is centered in the background of the title section.

SIMULATION OF WIND GENERATION PATTERNS FOR THE ERCOT SERVICE AREA

MAY 23, 2012

SUBMITTED BY:

AWS Truepower, LLC

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1. INTRODUCTION

In January 2012, AWS Truepower (AWST) was engaged by the Electric Reliability Council of Texas (ERCOT) to provide 15 years of wind power data for existing, planned, and hypothetical sites. These data were to be based on high-resolution simulations of the historical climate performed by a mesoscale numerical weather prediction (NWP) model covering the period 1997 through 2011.

The work was divided into the following technical tasks:

1. Generate historical wind and weather data for the ERCOT service area.
2. Work with ERCOT to compile a representative list of existing and proposed project sites and identify hypothetical sites for new wind projects in the service area.
3. Convert wind and weather data to power output.
4. Package and deliver time series of 15 years of power output at each site.
5. Compile results and report on findings.

Several assumptions have been made in order to facilitate the delivery of the requested data sets. These assumptions were proposed by AWST and then applied based on ERCOT's recommendations. This document presents AWST's final technical report on the methods used, the results achieved, and a validation of the data sets.

2. PREVIOUS ERCOT PROJECTS

AWST has previously performed similar studies for ERCOT. This study expands upon the previous work by increasing the study period and providing output for individual sites. The first study identified Competitive Renewable Energy Zones (CREZs) and characterized hourly, daily, and seasonal output of existing and future wind projects in proposed CREZs to enable assessment of potential transmission upgrades.¹ A summary of the steps used in that study are as follows:

- Created hourly output for a typical year (sampled from 1990-2004)
- Used Texas MesoMap for map adjustment and hourly wind speeds (validated with 64 towers)
- Employed site screening
- Total of 1200 sites (13 GW) covering each region of Texas
- Each site was at least 100 MW and above a specified minimum net capacity factor
- Identified 25 Competitive Renewable Energy Zones (CREZs)
- Output was provided for 4000 MW of capacity in each CREZ (not individual sites)

A subsequent study used the CREZs selected from the first study to produce model-derived wind plant output and forecast data for two continuous years.² Details are summarized as follows:

- Generated hourly and 1-minute plant output, 4 hour ahead and next day hourly forecasts
- Modeled hourly 80-m wind speeds for 2005–2006 (10 km resolution)

¹ AWS Truewind, LLC, "Wind Generation Assessment", Report to ERCOT, January 2007.

² AWS Truewind, LLC, "Wind Generation and Forecasting Profiles", Report to GE Energy Consulting, October 2007.

- Converted to power output
- 716 sites in 25 CREZs from previous study
- Provided output for each site so different scenarios within each CREZ could be tested
- Locations of sites were not provided, but location of CREZs were

The current study employs similar methodology as the most recent work but extends the time period from two years to 15 years of hourly simulated data. Additionally, power profiles were delivered for individual sites rather than aggregated to each CREZ.

3. SITE SELECTION

AWST worked with ERCOT to identify existing, proposed (queue), and hypothetical sites, with the aim of generating over 25 GW of onshore sites. ERCOT also requested offshore sites totaling 1500 MW.

The site selection process operated in four distinct phases. The first phase identified the existing wind plants in the ERCOT service area. ERCOT provided AWST with a list of existing and queue wind plants. This list included the approximate location and capacity of each site. AWS Truepower then gathered mean wind speed and elevation data for each wind farm by digitizing the wind turbine occupied area in a GIS software package. Figure 1 shows an example of a wind farm digitized from individual turbine locations. The wind turbine locations were provided by AWS Truepower's Wind Farm and Turbine Inventory database (WFTI). The AWST WFTI is compiled from the Federal Aviation Administration public record of tall towers and aerial imagery from Landsat.

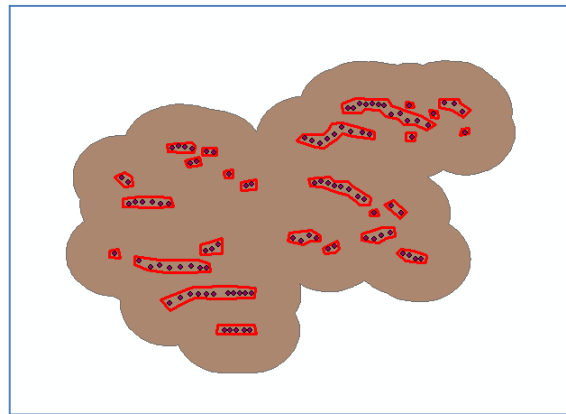


Figure 1. Example of an existing wind farm digitized (red polygons) for use in this study. The brown area indicates a 2-km buffer around each turbine identified from the WFTI database. Individual turbines are indicated in black.

The second phase identified queue sites in a different manner. AWST ran GIS-based site selection software to build sites based on wind resource and excluded areas within a range of the approximate locations provided by ERCOT. To provide a consistent set of resource estimates for ranking and selecting sites, a seamless map of predicted mean wind speeds at 80 m for the ERCOT region was prepared from AWS Truepower's proprietary wind maps. This map was generated at a horizontal resolution of 200 m which is sufficiently fine to reflect the influence of most terrain features and to identify specific locations for wind projects. AWS Truepower has developed a method of adjusting its wind maps using a wide

array of wind resource measurements to ensure good accuracy.³ A map of the estimated net capacity factor for a composite International Electrotechnical Commission (IEC) Class 2 wind turbine⁴ was then created using the seamless wind speed map at 80 m and speed-frequency distributions compiled from 15 years of historical mesoscale model runs (a total of 366 randomly sampled days) previously performed by AWS Truepower at 10 km resolution. Although IEC Class 2 turbines are not suitable for every site, the use of a single power curve allowed for an objective ranking of resource potential. The composite power curve was created by taking the average of three commercial megawatt-class wind turbine power curves which had been normalized to their rated capacity. The composite curve is shown in Table 1.

Table 1. Composite power curves.

Speed	IEC - 1	IEC - 2	IEC - 3	Offshore
0	0	0	0	0
1	0	0	0	0
2	0	0	0	0
3	0	0	0.0063	0
4	0.0195	0.0283	0.0412	0.0252
5	0.0681	0.0884	0.102	0.0704
6	0.1401	0.1739	0.189	0.1296
7	0.2371	0.2873	0.3107	0.2162
8	0.3663	0.4339	0.4715	0.3276
9	0.5233	0.6066	0.6629	0.4670
10	0.7021	0.7768	0.8383	0.6340
11	0.8564	0.905	0.9464	0.8034
12	0.9556	0.9717	0.9871	0.9510
13	0.9874	0.9926	0.9976	1
14	0.9945	0.9979	0.9995	1
15	0.9982	0.9998	0.9999	1
16	0.999	1	1	1
17	1	1	1	1
18	1	1	1	1
19	1	1	1	1
20	1	1	1	1
21	1	1	1	1
22	1	1	0	1
23	1	1	0	1
24	1	1	0	1
25	1	1	0	1

The site screening took into account the following areas excluded from development:

- From the United States Geological Survey National Land Cover Database (2001):

³ The mean bias of the AWS Truepower 200-m USA wind map is found to be virtually zero, while the standard error (after accounting for uncertainty in the data) is 0.35 m/s.

⁴ IEC Class 2 turbines are typically used for sites with 7.5–8.5 m/s average wind speeds at hub height.

- Open water
- 200-m buffer of developed low intensity
- 500-m buffer of developed medium intensity
- 500-m buffer of developed high intensity
- Woody wetlands
- Emergent herbaceous wetland
- From the Environmental Systems Research Institute database:
 - Parks
 - Parks detailed
 - Federal lands (non-public)
 - 10,000-ft. buffer of small airports (all hub sizes)
 - 20,000-ft. buffer of large airports (hub sizes medium and large)
- Other:
 - Slopes greater than 20%
 - Areas outside the study region
 - Areas of natural and scientific interest (ANSI)
 - 2km buffer around existing wind farms

Based on the net capacity factor map, areas excluded from development, and the queue site capacities and approximate locations, the site selection software finds all sites with the desired output in the immediate vicinity (i.e., a local maximum) with sufficient area to support a project of the desired rated capacity. The software reviews the candidate sites and retains the site with the highest capacity factor, dropping the other sites. This process is conceptualized in Figure 2.

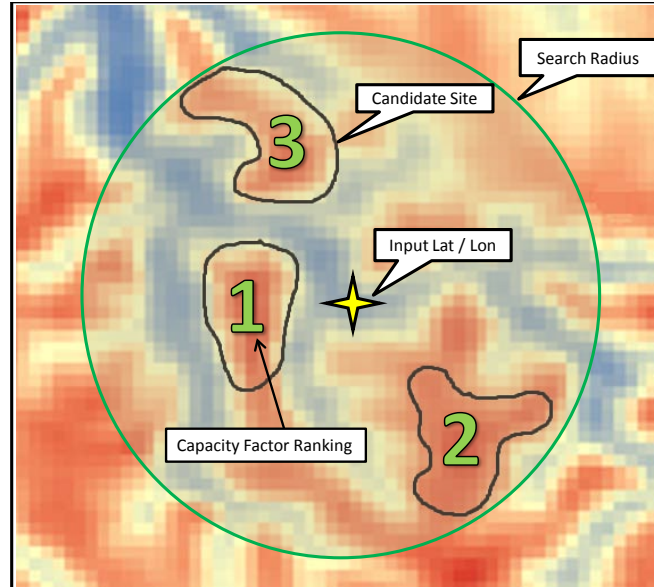


Figure 2. A conceptual depiction of the site selection process. Cool colors indicate lower capacity factor values.

Once the existing and queue wind plants were identified, the third site selection phase identified hypothetical sites. A 2-km buffer around each identified existing and queue site was created and added to areas excluded from development to ensure unique hypothetical sites. A similar site selection algorithm was then employed, with the exception that instead of supplying approximate locations, capacities, and search radii, the algorithm determines likely locations of hypothetical sites within a specified range of capacities based on the available wind resource. The screening for hypothetical sites employs two steps. In the first step, the program finds all sites with a maximum output in the immediate vicinity as before. In the second step, the program allows each of these sites to expand so long as the output does not decrease by more than 5%. If the site encounters another site, the site that has a higher mean output is retained and the other is dropped. The program was run in an iterative process until the nameplate capacity target by county was reached.

A fourth phase of site selection identified 3 offshore sites totaling 1500 MW. ERCOT provided AWS Truepower a list of three counties in Texas where nearby offshore wind development is expected. AWS constructed three 500 MW plants (one for each nearby county) in the offshore area waters. These sites were placed in areas that were least 5 miles from shore and in waters less than 30 m deep. No other restrictions on offshore development were applied. For each offshore development region, AWS Truepower selected an area with the greatest expected capacity factor that could support 500 MW of wind development.

Figure 4 shows the locations of existing, queue, and hypothetical sites overlaid on the average annual capacity factor map at 80 m above ground level. The sites are summarized in Table 2, while Appendix A contains the final list of 228 sites approved by ERCOT for use in this study.

Table 2. Summary of sites used in the study including the total number of each type and total GW of power selected.

PLANT TYPE	NUMBER	GW
Existing Sites	84	9.9
Queue Sites	11	1.9
Hypothetical Sites	130	17.9
Offshore Sites	3	1.5
Total	228	31.2

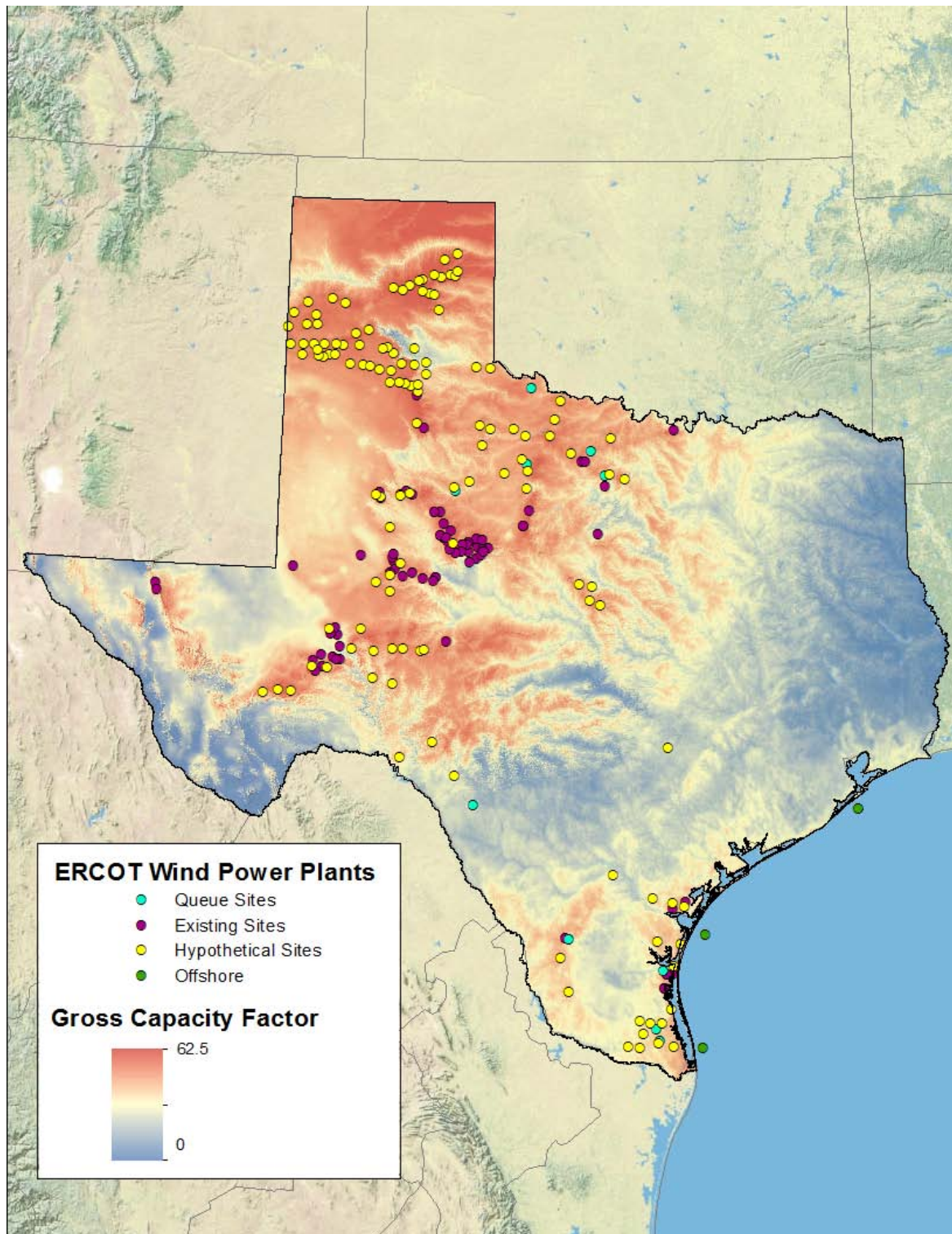


Figure 3. Annual capacity factor map at 80-m hub height and locations of all sites in the study. Each site type is identified by different color circles.

4. MESOSCALE MODELING

Meteorological data used to produce wind power output profiles at each selected site was generated with the Mesoscale Atmospheric Simulation System (MASS), a proprietary numerical weather prediction model developed by AWST partner MESO, Inc.⁵ MASS is a non-hydrostatic weather model which has been customized for near-surface wind and irradiance prediction. MASS simulates the fundamental physics of the atmosphere including conservation of mass, momentum, and energy as well as the moisture phases using a variety of online, global, geophysical and meteorological databases. The main meteorological inputs are reanalysis data, rawinsonde data, and land surface measurements. The reanalysis database – the most important – is a gridded historical data set produced by the U.S. National Centers for Environmental Prediction and National Center for Atmospheric Research (NCEP/NCAR Reanalysis; NNGR). The data provide a snapshot of atmospheric conditions around the world at all levels of the atmosphere in intervals of six hours. Along with rawinsonde and surface data, the reanalysis data establish the initial and lateral boundary conditions for the MASS runs. The MASS model itself determines the evolution of atmospheric conditions within the region based on the interactions among different elements in the atmosphere and between the atmosphere and the surface.

The reanalysis data are on a relatively coarse grid (about 210-km spacing). To avoid generating noise at the boundaries that can result from large jumps in grid cell size, mesoscale models such as MASS are typically run using nested grids of successively finer mesh size until the desired grid scale is reached. In this configuration, the outer grid provides initial guess fields and updated lateral boundary conditions for each subsequent nest of an inner grid. For this study, a nested grid scheme with horizontal resolutions of 30 km and 8 km was used (Figure 4). The runs cover Texas and its offshore for the period 1 January 1997 to 1 January 2012. Table 3 summarizes the model configuration used in this study.

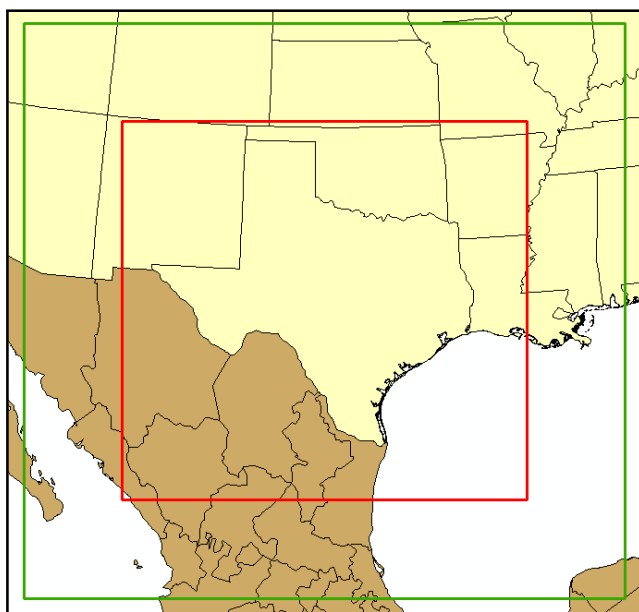


Figure 4. ERCOT study area and proposed mesoscale model configuration. The model configuration includes nested grids of 30-km (green) and 8-km (red) grid spacing.

⁵Manobianco, J., J. W. Zack, and G.E. Taylor, 1996: Workstation-based real-time mesoscale modeling designed for weather support to operations at the Kennedy Space Center and Cape Canaveral Air Station. Bull. Amer. Meteor. Soc., 77, 653-672. Available online at <http://science.ksc.nasa.gov/amu/journals/bams-1996.pdf>.

Table 3. Model configuration for MASS runs.

Model	MASS v. 6.8
Initialization data source	NNGR
Data assimilated in the course of simulations	Rawinsonde, surface observations (temperature, dew point, wind direction and speed, pressure)
Sea-surface temperatures	MODIS (Moderate Resolution Imaging Spectroradiometer)
Cumulus scheme	Kain-Fritsch
Spin-up	12 hours before start of valid run
Length of run	15-16 day series (e.g., Jan 1-15, Jan 16-31)
Frequency of data sampling	Hourly
Data stored	Wind speed and direction, temperature, pressure, TKE at five heights; surface temperature and pressure, specific humidity, incoming long-wave and short-wave radiation, precipitation

5. GENERATION OF WIND PLANT OUTPUT

An algorithm written by AWST was used to convert the meteorological data generated by the mesoscale model to wind plant output. The software starts by reading a list of seven tall towers⁶ in the validation region and their nearest associated grid cells (grid number and column and row position). It also reads a list of the grid cells associated with the sites. Up to eight 8-km grid cells are associated with each site, depending on its size and shape and if it falls along the boundary of grid cells. For each cell, the list provides the latitude and longitude, expected mean speed of the part occupied by turbines, mesoscale grid cell elevation, actual mean elevation of the turbines, and relative proportion of the site's total rated capacity associated with that cell. The mean speeds are based on AWS Truepower's 200-m resolution wind map. An example of 200-m map grid cells within four 8-km model grid cells for a hypothetical site is shown in Figure 5.

⁶ The location of the tall towers is proprietary, and therefore not disclosed in this report.

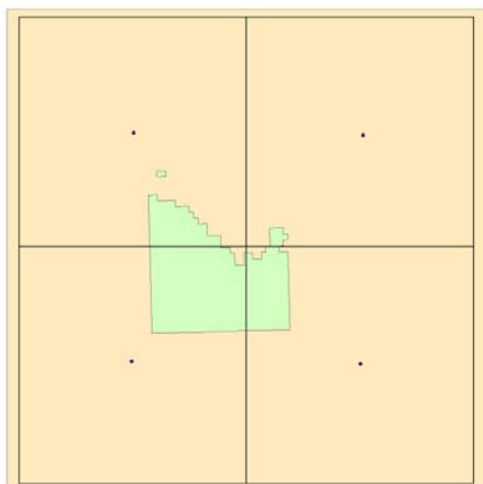


Figure 5. Example of 200-m map cells within 8-km model grid cells for a hypothetical site.

The program then imports the turbine power curves. The appropriate power curve was applied at each site, reflecting the estimated IEC site classification. A composite power curve was created from commercially available turbines for each IEC class (see Table 1). The power curves are scaled to a rated capacity of 2 MW and are valid for the standard sea-level air density of 1.225 kg/m^3 . The IEC 1 and 2 turbines are assumed to have a hub height of 80 m and the IEC 3 turbine 100 m. It is assumed that the lower hub height will be used unless the wind resource dictates moving to a higher hub height to capture more wind. The program next reads a set of 12x24 speed matrixes, one for each of the validation towers. These matrixes give the mean speed for each hour of the day and for each month of the year. For each tower there are two matrixes, one for each hub height (80 m and 100 m).⁷ The program reads the mesoscale time series file for each of the grid points nearest the validation towers. From the wind speed data, it creates a 12x24 mean speed matrix for each hub height. The ratio between the average observed and average simulated speed is then calculated for each bin and normalized to an average of one. The result is an adjustment matrix which is used to correct model biases. Although the program calculates adjustments on a monthly basis, it was found during the validation phase that the monthly variation in speeds was accurately predicted by the model. Therefore, only an annual adjustment is performed.

The mesoscale time series files are then read for each grid cell associated with a project site. The speed data are scaled to match the expected mean speed and finally summed for all the grid cells associated with the site. In the sum, each cell's speeds are weighted according to the proportion of the site area associated with that cell. The result is a time series of simulated wind speeds for the site as a whole at both 80 m and 100 m.

The program calculates a correlation coefficient (r^2) between the simulated daily mean speeds for the site in question and the simulated daily mean speeds for each validation location. It then calculates a weighted average adjustment matrix for the site in which the weight given to the adjustment matrix for each validation location is proportional to its correlation coefficient. The program applies this blended

⁷ The matrixes were created from the tall tower observations, smoothed with data from long-term reference stations where necessary. In cases where the monitoring height was lower than the modeled hub heights, the diurnal shear distribution was used to extrapolate to 80 and 100 m.

adjustment matrix to the simulated data for the site. For example, if the time in question is 1300, the simulated speed is multiplied by the adjustment factor for 1300.

The speed at each grid point is then adjusted for wake losses in a manner that depends on the simulated wind direction relative to the prevailing (most frequent) direction. The loss is given by $w = w_{\min} + (w_{\max} - w_{\min}) \sin^2(\theta - \theta_{\max})$, where w_{\min} is the minimum loss (assumed to be 4%) when the wind is aligned with or opposite to the prevailing direction θ_{\max} , and w_{\max} is the maximum loss (9%) when the wind is perpendicular to the prevailing direction. The loss factors account both for wake losses and implicitly for other losses such as blade soiling that affect the efficiency of power conversion for a given free-stream speed without reducing the maximum output. These losses were determined by trial and error to conform to AWS Truepower's estimates for actual wind projects. The method does not account for sites where there is more than one prevailing wind direction or where the prevailing energy-producing direction differs from the most frequent direction. In these cases, only the most prevalent wind direction is used.

The speed is further adjusted by adding a random factor (from -1 to +1) multiplied by the predicted TKE. This adjustment is intended to reflect the impact of gusts on the speeds experienced by the turbines in the wind project. The frequency and intensity of such simulated gusts depends to a degree on time of day, as TKE is generally higher in the day when the planetary boundary layer is thermally unstable or neutral than at night when it is thermally stable.

The program selects the most appropriate IEC class based on the estimated maximum long-term annual mean speed within the site based on the ERCOT wind map, adjusted for air density. The program then applies an additional power loss to account for turbine and plant availability. Based on data obtained by AWS Truepower for operating wind projects, the availability is assumed to follow a normal distribution with a mean of 94.8% and a standard deviation of 2.3%; the distribution is truncated at 100%. To avoid unrealistic rapid fluctuations in output, the availability is allowed to change at random intervals averaging only once per hour. An additional loss of 3% is subtracted from the output to represent electrical losses.

The resulting output at each site is then adjusted to reduce the impact of observations assimilated into the mesoscale model every 12 hours. This adjustment removes a small correlated component of the variability from each site, resulting in a more realistic, consistent diurnal variability when all simulated sites are aggregated across the system.

A 15-year time series of hourly power output was created at each site. A sample text file of site output is shown in Table 4. The header includes the site number, rated capacity, and IEC class of the site, along with the wind speed level used in the calculations and the resulting average loss applied at the site. ERCOT requested the data be reformatted into yearly files that included all sites as shown in Table 5, with all times in local time (Central Standard Time, CST) rather than Greenwich Mean Time (GMT) as was provided in the original site files.

Table 4. Sample plant output data file

SITE NUMBER:		1
CAPACITY (MW):		757
IEC CLASS:		1
WIND SPEED LEVEL (M):		80
AVERAGE LOSS (%):		16.86
YYYYMMDD	HHMM(GMT)	OUTPUT(MW)
19970101	0000	366.9
19970101	0100	326.2
19970101	0200	291.1
19970101	0300	378.7
19970101	0400	417.5
19970101	0500	492.1
19970101	0600	574.4
19970101	0700	497.3

Table 5. Sample yearly data file.

YYYYMMDD	HHMM (CST)	SITE_00001: capacity= 112.5	SITE_00002: capacity= 77.2	SITE_...	SITE_20003: capacity= 500.0
19970101	1900	80.37	5.07	...	127.26
19970101	2000	70.94	3.39	...	133.47
19970101	2100	51.89	3.51	...	146.3
19970101	2200	44.81	11.04	...	218.41
19970101	2300	33.19	61.91	...	215.01

6. VALIDATION

The delivered data sets underwent a detailed validation process to ensure the results were consistent with actual meteorological and power generation observations. AWST used as much publicly and privately available observed data as possible at the time of the study. This included nine National Weather Service Automatic Surface Observing System (ASOS) stations, seven proprietary tall tower measurements, and wind power output from 10 ERCOT generation facilities. Each of these data sources was independently validated against the modeled data to determine the accuracy of the provided data sets.

ASOS winds are measured at a standard 10-m height. Nine stations across Texas were used to compare winds from the MASS model runs at 10 m. Figure 6 demonstrates the results from this analysis, showing two of the ASOS stations (Abilene and Port Isabel Cameron) and the nearest corresponding modeled grid point. The plots compare the deviation from the long term average wind speed and show the monthly 10 m correlation coefficient between the ASOS and modeled locations. The interannual variability of the simulated wind speed compares well with the observed wind speed at all nine

locations, with the model trending particularly close to the observations on a monthly basis with an average correlation coefficient of 0.743.

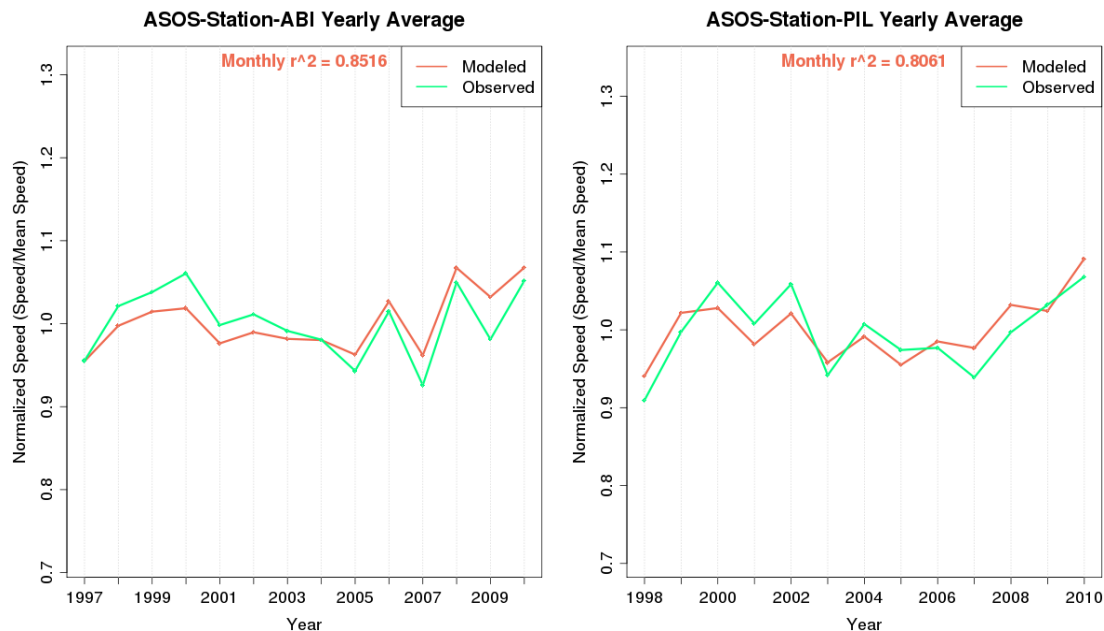


Figure 6. Comparison of the long term modeled wind speed at two ASOS stations in the ERCOT region.

The modeled 80-m wind speeds were compared to wind speeds measured at seven validation towers and sheared to 80 m by assuming a shear coefficient derived from 40 m and 60 m AGL measurements. The comparisons for Tower 3 and Tower 6 (Figure 7 and Figure 8) indicate close agreement in the patterns on an annual, monthly and diurnal basis with a very moderate bias and spread of wind speed errors. The correlation on all time scales is certainly acceptable, with the hourly r^2 value of 0.525, the daily r^2 value of 0.79 and the monthly r^2 value of 0.892 for validation tower 3. This relationship exemplifies the model's ability to capture monthly and diurnal variations in the local climate.

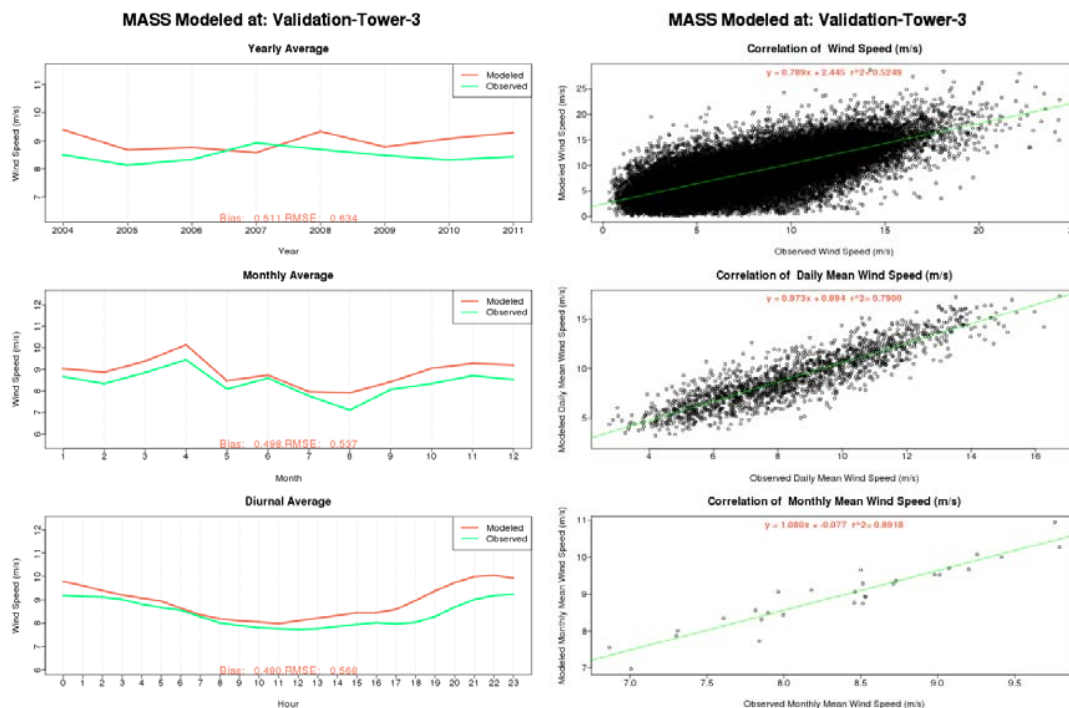


Figure 7. Comparison of simulated and observed mean wind speed on an annual, monthly and diurnal basis at validation tower 3. Hourly, daily and monthly scatter plot of observed vs. modeled showing the correlation between modeled and observed speeds.

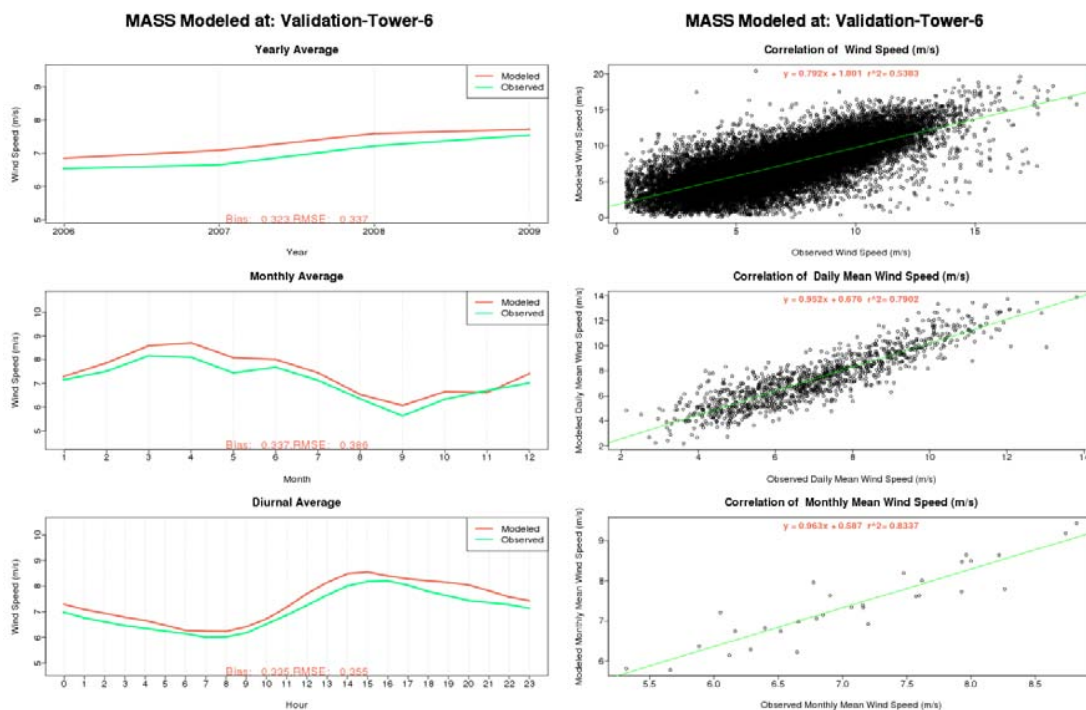


Figure 8. As in Figure 7 except for validation tower 6.

The wind power validation consisted of making direct comparisons with actual power generation data for ten power plants in the ERCOT region. In order to best characterize the difference between the modeled and observed power, these select number of sites were chosen based on preferable specifications detailed in the WFTI database, i.e. only power plants containing turbines with 80 m hub heights, known plant layouts and easily accessible power curve information were used for the analysis. The actual layouts were then modeled and compared against the power observations. Only the overlapping period of record was compared (generally 2005–2007), and times with unavailable generation data were set to missing in the modeled time series to facilitate a fair comparison.

The analysis shows that the model is able to capture the dynamic behavior of the wind plants in Texas quite well. The modeled seasonal and diurnal mean patterns are shown to be very similar to the observed but are biased slightly high, approximately 2.5% at Site 3 (Figure 9 and Figure 10). Some of the discrepancies may be caused by limitations in the numerical model or by a mean difference in the annual map speed while others are due to problems with wind plant performance (including availability and wind curtailment, see Figure 11). Overall the model is able to reproduce the increased power generation during nighttime hours when the height of the boundary layer is considerably lower and winds are stronger while predicting the seasonally dependent wind climate with acceptable accuracy.

Next the frequency distribution of hourly step changes in power output was compared to ensure that the model captures the variability of actual wind farms. Results at 3 ERCOT sites are shown in Figure 12. The changes are shown as a percentage of plant capacity, with the y-axis shown on a logarithmic scale to emphasize large ramps. The model variability compares well with the observed at each individual plant, as well as the aggregate of four wind power plants (Figure 12, bottom right). The aggregate ramp distribution demonstrates how geographic diversity and accumulating wind power generation tends to decrease the overall system fluctuation from hour to hour.

The correlation of hourly plant output was then compared at four of the power generation facilities. Approximately two years of hourly generation data was used to compute the linear regression coefficient (R) between each combination of plants. Figure 13 shows the correlation of Site 1 with each of the other locations. The results show that the model is slightly more correlated than the observed power, but still approximates the output well. The lower correlation in the observed data may also be attributed to wind curtailment or downtime at the facility. A similar comparison was done for the step change in power output. Additionally, the correlation coefficient was plotted against the distance between plants (Figure 14). It was found that the model tends to be slightly more correlated in space, but overall the modeled data exhibits realistic correlations when compared to the observed power data. Accurate spatial correlation is important because if output variations are highly correlated between projects, the benefit of geographic diversity is small, whereas little correlation between projects confers a large diversity benefit.

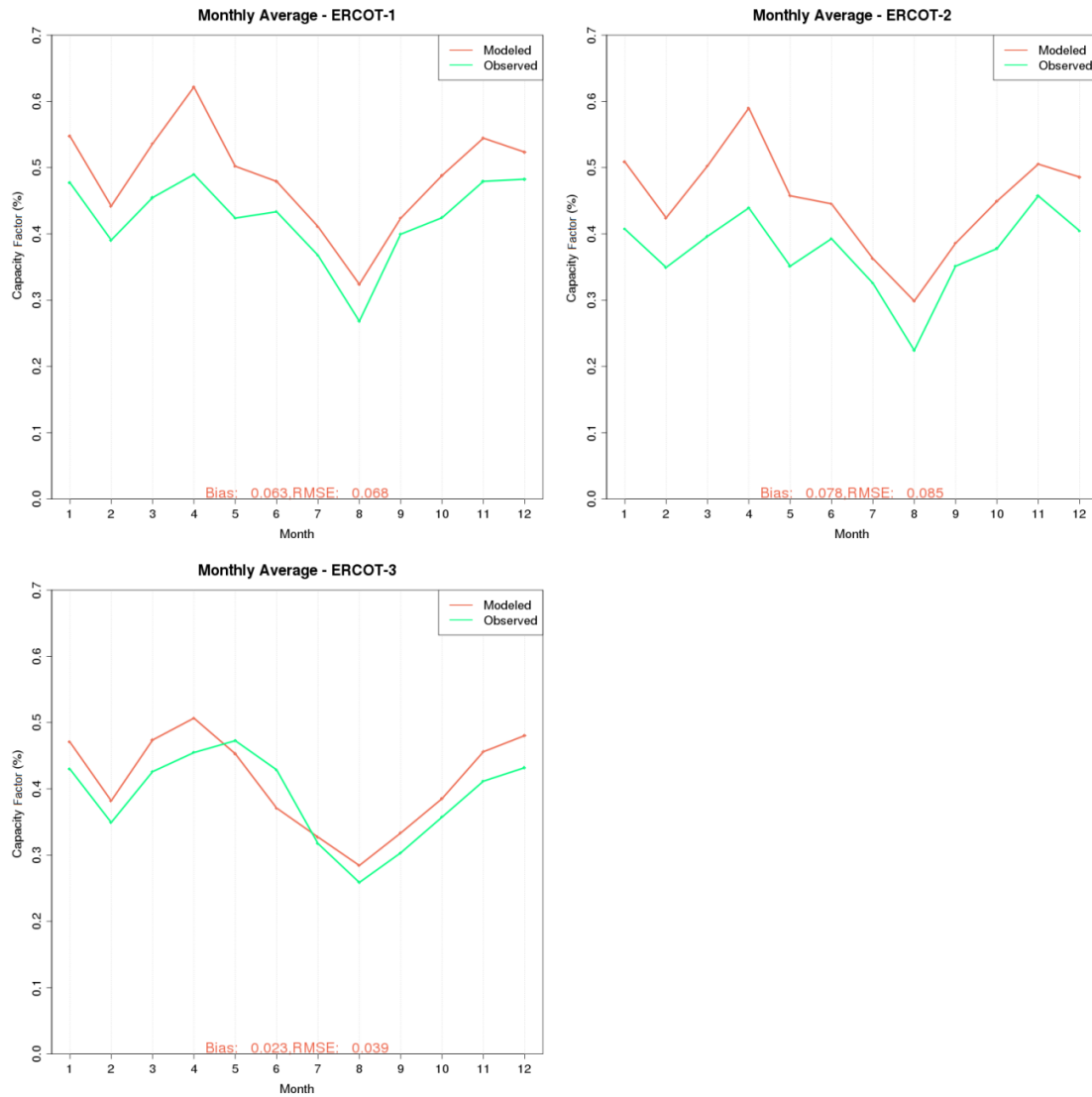


Figure 9. Comparison of monthly average capacity factors for three ERCOT power stations modeled at the nearest site.

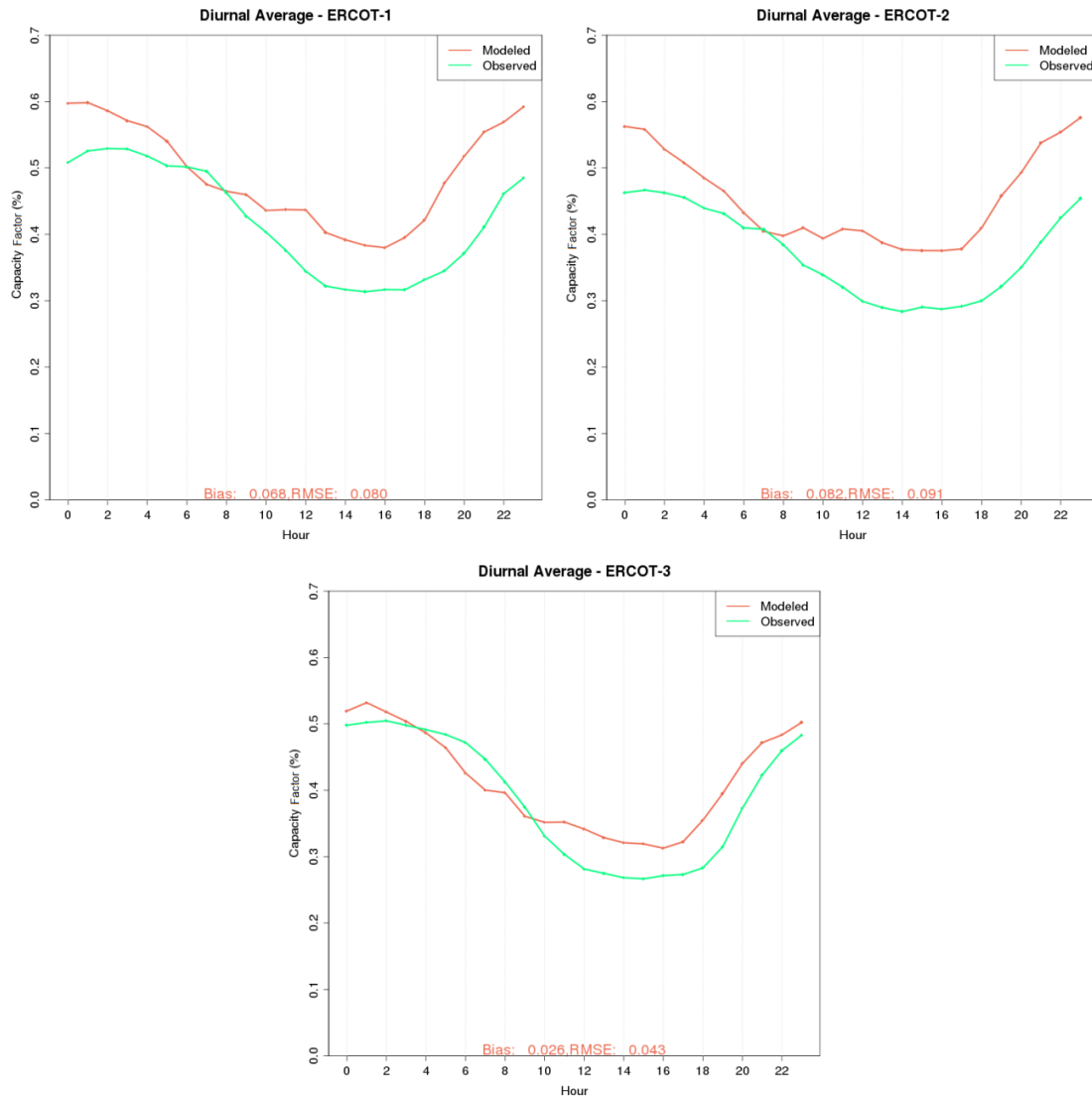


Figure 10. Comparison of diurnal average capacity factors for three ERCOT power stations modeled at the nearest site. Time is in Central Standard Time.

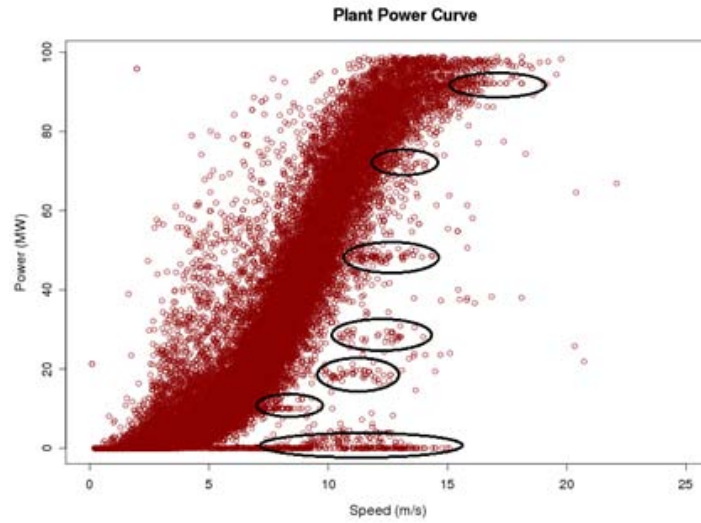


Figure 11. Example power output plotted as a function of wind speed with black ovals highlighting suspicious data points.

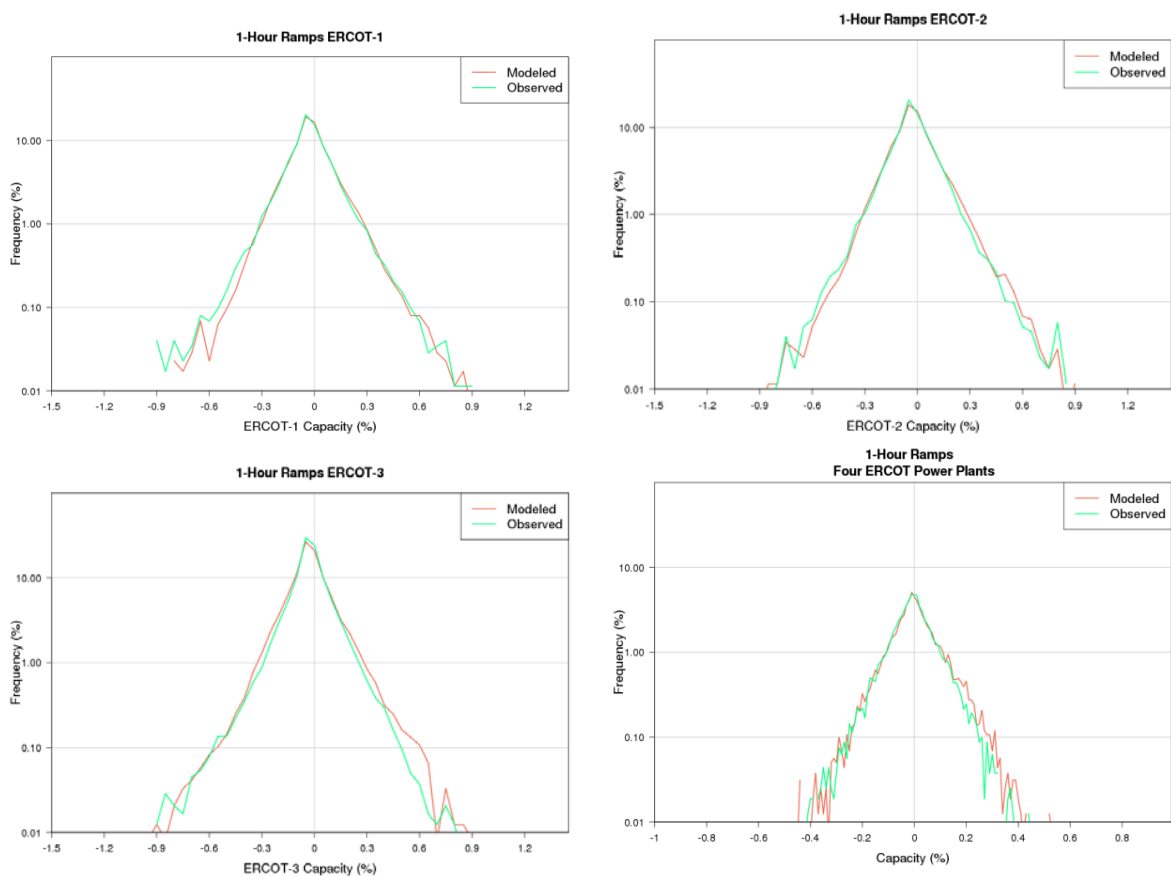


Figure 12. Comparison of 60-minute changes in power output on a logarithmic scale observed at three ERCOT stations as well as the aggregate of four ERCOT power generating facilities.

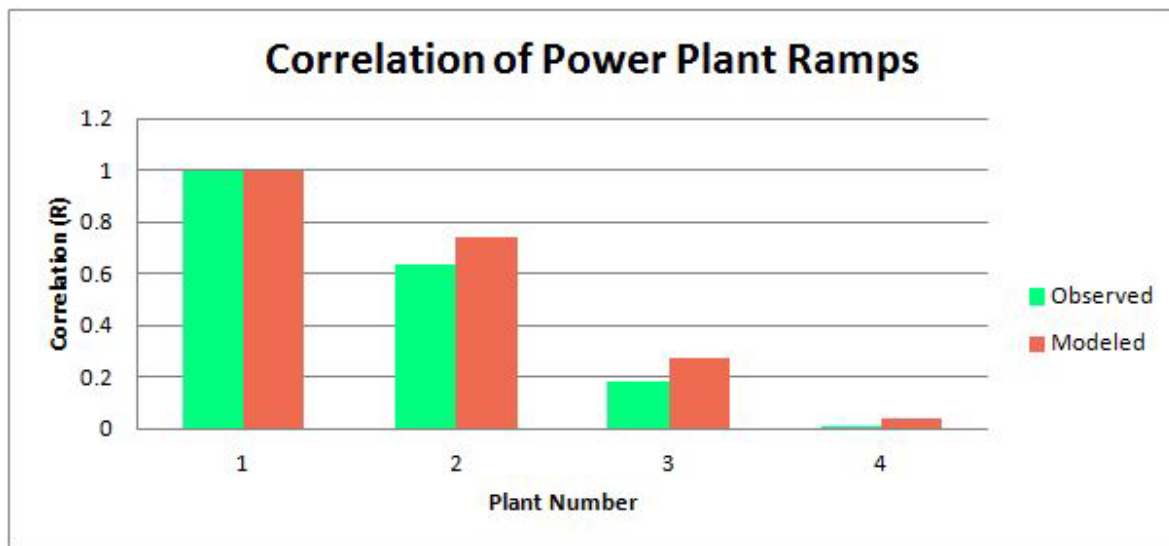
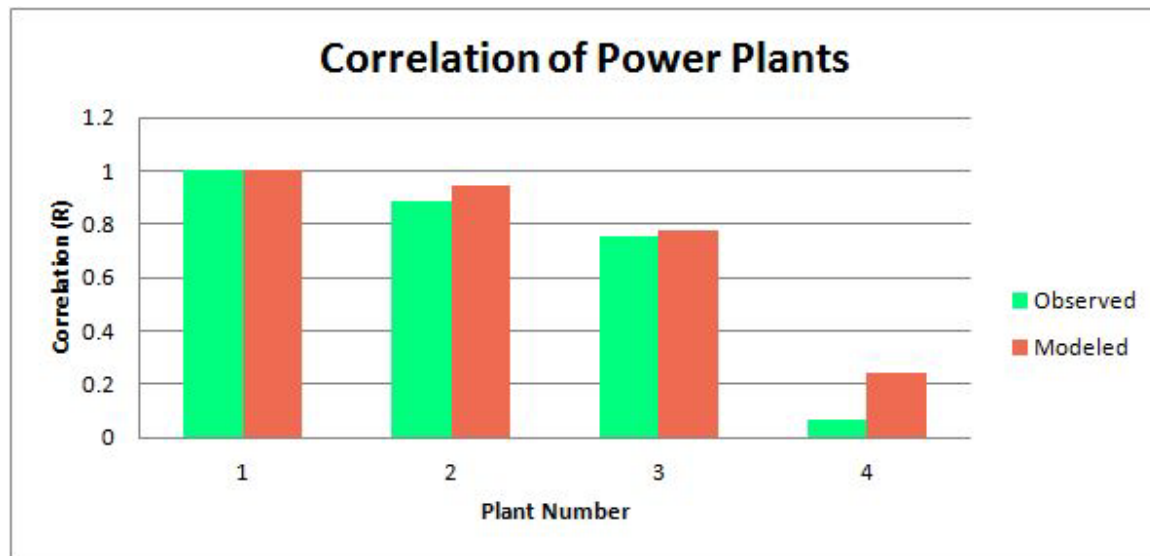


Figure 13. Correlation between modeled and observed power plants at four generating facilities. Shown for power generation and step change in power.

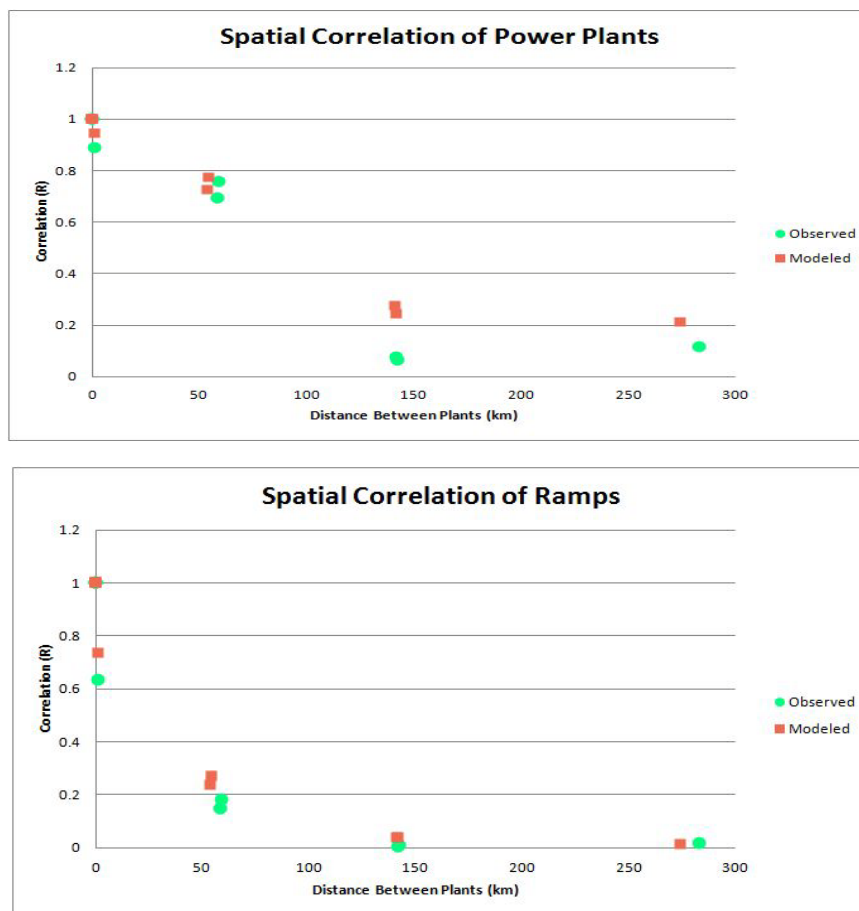


Figure 14. Spatial correlation of power plant output and step change in power at four generating facilities.

7. ACCURACY SUMMARY

Validation of modeled wind speeds against tall tower measurements and modeled power output against generation data at several existing plants was undertaken to ensure accuracy of the data set. Diurnal and monthly mean wind speeds validated well against observations at nearly all sites examined. Although some discrepancies were noted, diurnal and monthly mean modeled power output also compared with patterns observed at existing plants with acceptable accuracy. Comparison of hourly ramps in power output showed that the modeled data matches the variability observed at actual plants quite well.

It is not expected that the simulated wind and power profiles will exactly match the actual at a particular time or place. Some discrepancies may arise due to limitations in the numerical weather modeling, such as the finite grid resolution. Others may be caused by differences in assumed turbine model or wind plant performance (including low availability, curtailments, or outages).

No model is a perfect reflection of reality. However, the validation process confirmed that the data reflect realistic averages, seasonal and diurnal patterns, and ramping behavior of wind speed and power production for Texas wind farms, and should provide a solid basis for hourly grid impact simulations.

8. DATA SET USAGE

The data set was developed specifically for use in wind integration and transmission studies for the purpose of matching the relative changes in wind power output across time and space. It should be noted that modeled data is not a replacement for onsite measurements and should not be used as the only basis for investment decisions.

AWS Truepower maintains a secure offsite archive of the mesoscale model simulations performed for clients. Should the need arise for more wind plants or different technologies to be simulated in the ERCOT region, AWS Truepower can readily support these scenario building activities with 3 weeks of lead time (for offsite data retrieval and restoration).

9. CONCLUSIONS

AWST employed a numerical weather prediction model to simulate 15 years of hourly wind speeds and power output profiles for wind generation facilities across Texas. A site selection process identified existing, planned, and hypothetical wind generation facilities totaling over 29 GW onshore and 1.5 GW offshore. Power output profiles were developed for each site identified using common commercially available turbine power curves as of May 2012 and AWST's standard power conversion and loss estimation techniques. Wind speeds and power profiles were validated against available measurements and were found to capture the dynamic behavior of actual wind farms with acceptable accuracy. The data therefore appear to provide a sound basis for long-term system planning as well as transmission system and resource adequacy studies within the ERCOT region.

APPENDIX A: SELECTED SITES

SITE_ID	PLANT TYPE	LATITUDE	LONGITUDE	MW
1	Existing Sites	33.738	-97.359	112.5
2	Existing Sites	30.888	-102.486	77.2
3	Existing Sites	30.966	-102.366	82.5
4	Existing Sites	34.144	-101.109	59.8
5	Existing Sites	32.380	-100.630	126.5
6	Existing Sites	32.171	-100.205	169.5
7	Existing Sites	32.195	-101.854	123.6
8	Existing Sites	31.079	-102.114	74.9
9	Existing Sites	32.983	-101.233	84.0
10	Existing Sites	31.990	-101.120	199.5
11	Existing Sites	27.130	-97.461	100.8
12	Existing Sites	27.931	-97.451	179.9
13	Existing Sites	32.122	-101.385	58.8
14	Existing Sites	32.028	-102.816	152.6
15	Existing Sites	31.167	-100.611	150.0
16	Existing Sites	31.220	-102.145	40.3
17	Existing Sites	31.239	-102.236	79.3
18	Existing Sites	31.293	-102.188	79.3
19	Existing Sites	31.757	-104.772	39.8
20	Existing Sites	30.833	-102.345	150.0
21	Existing Sites	30.770	-102.446	150.0
22	Existing Sites	30.947	-102.212	82.5
23	Existing Sites	32.508	-100.581	197.0
24	Existing Sites	32.765	-99.460	165.6
25	Existing Sites	31.940	-100.790	69.6
26	Existing Sites	31.940	-100.790	80.0
27	Existing Sites	32.740	-100.730	63.0
28	Existing Sites	32.175	-101.401	121.9
29	Existing Sites	31.673	-104.742	28.5
30	Existing Sites	28.006	-97.270	200.1
31	Existing Sites	32.742	-100.826	120.0
32	Existing Sites	32.742	-100.826	130.5
33	Existing Sites	32.301	-100.043	114.0
34	Existing Sites	27.572	-98.911	150.0
35	Existing Sites	32.360	-100.213	232.5
36	Existing Sites	32.316	-100.189	120.6
37	Existing Sites	32.290	-100.120	170.2
38	Existing Sites	33.070	-98.360	120.0
39	Existing Sites	32.958	-101.614	89.0

40	Existing Sites	32.894	-101.598	91.0
41	Existing Sites	32.942	-101.305	66.0
42	Existing Sites	32.948	-101.144	99.0
43	Existing Sites	26.962	-97.570	138.5
44	Existing Sites	26.962	-97.570	138.5
45	Existing Sites	30.919	-102.108	84.0
46	Existing Sites	30.922	-102.156	76.5
47	Existing Sites	31.224	-102.251	79.3
48	Existing Sites	32.586	-99.538	200.0
49	Existing Sites	32.584	-99.540	100.0
50	Existing Sites	32.584	-99.540	100.0
51	Existing Sites	27.130	-97.530	160.8
52	Existing Sites	27.130	-97.530	100.8
53	Existing Sites	32.420	-100.215	150.0
54	Existing Sites	32.411	-100.129	101.2
55	Existing Sites	31.920	-100.970	112.5
56	Existing Sites	32.368	-100.329	149.5
57	Existing Sites	32.368	-100.329	214.5
58	Existing Sites	31.900	-100.820	186.0
59	Existing Sites	32.258	-100.327	223.5
60	Existing Sites	32.261	-100.126	213.0
61	Existing Sites	32.223	-100.138	115.0
62	Existing Sites	32.266	-100.105	184.0
63	Existing Sites	32.420	-100.680	124.5
64	Existing Sites	32.423	-100.675	126.0
65	Existing Sites	32.455	-100.722	25.5
66	Existing Sites	32.450	-100.720	24.0
67	Existing Sites	31.944	-101.246	90.0
68	Existing Sites	32.027	-101.362	124.2
69	Existing Sites	31.984	-101.437	142.5
70	Existing Sites	31.980	-101.440	115.5
71	Existing Sites	33.759	-100.994	150.0
72	Existing Sites	32.591	-100.674	249.0
73	Existing Sites	32.207	-101.388	30.4
74	Existing Sites	32.346	-100.409	16.0
75	Existing Sites	32.343	-100.337	37.5
76	Existing Sites	32.346	-100.409	97.5
77	Existing Sites	32.266	-100.417	129.0
78	Existing Sites	32.247	-100.499	105.8
79	Existing Sites	32.284	-100.598	119.0
80	Existing Sites	32.139	-100.311	80.5

81	Existing Sites	32.430	-100.640	209.0
82	Existing Sites	32.490	-98.470	60.0
83	Existing Sites	33.366	-98.700	117.5
84	Existing Sites	33.359	-98.650	107.5
85	Queue Sites	33.498	-98.566	50.0
86	Queue Sites	32.997	-100.528	30.0
87	Queue Sites	33.333	-99.493	400.0
88	Queue Sites	26.463	-97.678	206.0
89	Queue Sites	26.325	-97.641	400.0
90	Queue Sites	27.563	-98.871	92.0
91	Queue Sites	29.185	-100.199	100.0
92	Queue Sites	34.254	-99.438	170.0
93	Queue Sites	27.176	-97.586	202.0
94	Queue Sites	33.196	-98.364	150.0
95	Queue Sites	32.503	101.473	120.0
1006	Hypothetical Sites	34.509	-101.163	100.3
1009	Hypothetical Sites	31.051	-101.956	107.3
1014	Hypothetical Sites	34.520	-101.346	142.2
1017	Hypothetical Sites	31.074	-101.230	100.0
1022	Hypothetical Sites	34.646	-101.461	120.5
1024	Hypothetical Sites	31.040	-100.981	117.2
1025	Hypothetical Sites	30.698	-101.640	94.6
1026	Hypothetical Sites	31.762	-101.427	100.7
1028	Hypothetical Sites	31.036	-101.630	94.9
1029	Hypothetical Sites	33.756	-99.689	100.0
1030	Hypothetical Sites	33.245	-99.485	100.7
1031	Hypothetical Sites	31.874	-101.624	139.3
1032	Hypothetical Sites	34.488	-100.042	99.8
1033	Hypothetical Sites	31.058	-101.379	164.4
1036	Hypothetical Sites	31.963	-101.436	125.7
1037	Hypothetical Sites	33.392	-99.561	101.0
1039	Hypothetical Sites	33.039	-99.500	101.8
1040	Hypothetical Sites	30.632	-101.358	94.5
1041	Hypothetical Sites	33.220	-99.818	100.8
1042	Hypothetical Sites	34.504	-100.248	102.3
1043	Hypothetical Sites	33.671	-99.516	197.4
1050	Hypothetical Sites	34.407	-100.973	173.6
1053	Hypothetical Sites	34.547	-100.979	136.2
1054	Hypothetical Sites	34.720	-101.164	101.5
2013	Hypothetical Sites	34.607	-102.405	101.3
2014	Hypothetical Sites	34.738	-102.207	117.3

2016	Hypothetical Sites	34.586	-102.502	151.7
2018	Hypothetical Sites	34.611	-102.321	150.9
2019	Hypothetical Sites	34.739	-101.976	123.6
2021	Hypothetical Sites	34.512	-102.101	116.8
2022	Hypothetical Sites	33.806	-101.107	182.5
2026	Hypothetical Sites	34.737	-102.491	119.3
2027	Hypothetical Sites	34.716	-101.560	104.1
2028	Hypothetical Sites	34.742	-102.316	127.9
2029	Hypothetical Sites	34.502	-101.901	133.0
2030	Hypothetical Sites	34.443	-101.491	116.3
2031	Hypothetical Sites	34.444	-101.674	102.4
2032	Hypothetical Sites	34.488	-101.812	162.8
2033	Hypothetical Sites	34.698	-101.625	129.2
3001	Hypothetical Sites	35.613	-100.651	237.8
3002	Hypothetical Sites	35.601	-100.574	131.6
3003	Hypothetical Sites	35.581	-100.795	198.9
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3006	Hypothetical Sites	35.611	-100.886	186.9
3007	Hypothetical Sites	35.411	-101.056	286.3
3008	Hypothetical Sites	35.370	-100.882	181.7
3009	Hypothetical Sites	35.194	-100.814	100.5
3011	Hypothetical Sites	34.587	-102.558	324.8
3014	Hypothetical Sites	34.715	-102.980	232.2
3015	Hypothetical Sites	34.595	-102.803	196.1
3017	Hypothetical Sites	34.731	-102.643	265.6
3018	Hypothetical Sites	34.727	-102.788	229.2
3019	Hypothetical Sites	34.666	-102.578	178.7
4001	Hypothetical Sites	35.484	-101.248	100.1
4002	Hypothetical Sites	35.539	-101.112	100.2
4003	Hypothetical Sites	34.185	-101.102	100.4
4004	Hypothetical Sites	35.425	-101.363	167.9
4005	Hypothetical Sites	35.449	-101.488	135.1
4006	Hypothetical Sites	34.267	-101.203	179.3
4007	Hypothetical Sites	32.953	-101.182	103.1
4011	Hypothetical Sites	34.280	-101.283	206.9
4014	Hypothetical Sites	33.559	-100.146	100.1
4015	Hypothetical Sites	34.299	-101.379	213.8
4016	Hypothetical Sites	32.928	-101.319	143.8
4017	Hypothetical Sites	33.752	-100.033	100.1
4018	Hypothetical Sites	34.289	-101.515	181.2

4019	Hypothetical Sites	32.897	-101.594	100.3
4021	Hypothetical Sites	33.791	-100.185	149.6
4025	Hypothetical Sites	32.930	-101.659	179.9
4026	Hypothetical Sites	32.533	-101.446	111.5
4030	Hypothetical Sites	34.273	-101.095	185.0
5002	Hypothetical Sites	26.254	-97.456	399.9
5003	Hypothetical Sites	26.293	-97.649	399.9
6001	Hypothetical Sites	32.101	-101.291	120.0
7001	Hypothetical Sites	29.531	-100.461	180.0
8001	Hypothetical Sites	31.672	-98.587	100.1
9001	Hypothetical Sites	35.663	-100.546	100.2
9003	Hypothetical Sites	35.793	-100.742	100.2
9012	Hypothetical Sites	30.518	-102.778	99.9
9018	Hypothetical Sites	30.811	-102.290	99.9
9023	Hypothetical Sites	30.519	-102.965	120.8
9027	Hypothetical Sites	35.875	-100.551	134.7
9035	Hypothetical Sites	34.871	-102.025	99.9
9038	Hypothetical Sites	35.238	-102.195	154.8
9043	Hypothetical Sites	33.680	-99.171	102.0
9045	Hypothetical Sites	34.936	-103.028	99.9
9047	Hypothetical Sites	32.352	-100.536	126.8
9048	Hypothetical Sites	34.973	-102.601	114.9
9049	Hypothetical Sites	34.931	-101.831	107.7
9051	Hypothetical Sites	35.299	-102.394	127.4
9053	Hypothetical Sites	30.485	-103.170	121.4
9059	Hypothetical Sites	35.089	-102.614	110.7
9063	Hypothetical Sites	35.109	-102.945	127.8
9064	Hypothetical Sites	30.816	-102.505	131.2
9065	Hypothetical Sites	35.239	-102.753	100.0
9071	Hypothetical Sites	34.972	-102.760	195.8
9075	Hypothetical Sites	31.063	-100.927	119.4
9077	Hypothetical Sites	31.881	-98.733	104.4
9080	Hypothetical Sites	33.460	-98.861	100.0
9100	Hypothetical Sites	34.100	-99.009	127.5
9111	Hypothetical Sites	33.872	-99.097	138.6
9120	Hypothetical Sites	31.286	-102.268	120.7
9130	Hypothetical Sites	33.652	-98.279	100.1
9155	Hypothetical Sites	27.223	-97.438	100.1
9161	Hypothetical Sites	33.148	-98.085	99.9
9162	Hypothetical Sites	31.622	-98.436	160.2
9168	Hypothetical Sites	29.933	-100.789	99.9

9192	Hypothetical Sites	26.711	-97.474	122.9
9199	Hypothetical Sites	33.035	-100.533	134.9
9208	Hypothetical Sites	31.292	-101.830	157.0
9216	Hypothetical Sites	29.749	-101.237	103.0
9217	Hypothetical Sites	27.334	-98.987	100.0
9237	Hypothetical Sites	27.502	-97.348	100.0
9238	Hypothetical Sites	33.206	-98.302	128.9
9244	Hypothetical Sites	33.116	-100.317	132.9
9297	Hypothetical Sites	31.846	-98.558	172.4
9303	Hypothetical Sites	27.525	-97.659	100.1
9311	Hypothetical Sites	27.955	-97.287	100.4
9334	Hypothetical Sites	26.924	-98.867	110.8
9342	Hypothetical Sites	26.541	-97.612	100.0
9360	Hypothetical Sites	27.990	-97.441	120.1
9408	Hypothetical Sites	26.404	-97.860	100.5
9411	Hypothetical Sites	26.232	-97.907	100.5
9419	Hypothetical Sites	28.049	-97.715	100.0
9441	Hypothetical Sites	26.258	-98.065	100.1
9471	Hypothetical Sites	26.539	-97.759	163.8
9489	Hypothetical Sites	26.569	-97.911	135.3
9518	Hypothetical Sites	28.334	-98.264	99.9
9592	Hypothetical Sites	29.884	-97.487	100.1
20001	Offshore	29.098	-94.866	500.0
20002	Offshore	27.608	-97.012	500.0
20003	Offshore	26.230	-97.053	500.0

**Appendix U Long-Term Assessment of Natural Gas
Infrastructure to Serve Electric Generation Needs within
ERCOT**

**Long-Term Assessment of Natural Gas Infrastructure to Serve Electric
Generation Needs within ERCOT.
Black & Veatch Report to ERCOT**

LONG-TERM ASSESSMENT OF NATURAL GAS INFRASTRUCTURE TO SERVE ELECTRIC GENERATION NEEDS WITHIN ERCOT

Prepared for

The Electric Reliability Council of Texas

JUNE 2013



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Black & Veatch Statement

This report was prepared for the Electric Reliability Council of Texas (“Client”) by Black & Veatch Corporation (“Black & Veatch”) and is based in part on information not within the control of Black & Veatch.

In conducting our analysis, Black & Veatch has made certain assumptions with respect to conditions, events, and circumstances that may occur in the future. The methodologies we utilize in performing the analysis and making these projections follow generally accepted industry practices. While we believe that such assumptions and methodologies as summarized in this report are reasonable and appropriate for the purpose for which they are used; depending upon conditions, events, and circumstances that actually occur but are unknown at this time, actual results may materially differ from those projected.

Readers of this report are advised that any projected or forecast price levels and price impacts reflect the reasonable judgment of Black & Veatch at the time of the preparation of such information and are based on a number of factors and circumstances beyond our control. Accordingly, Black & Veatch makes no assurances that the projections or forecasts will be consistent with actual results or performance. To better reflect more current trends and reduce the chance of forecast error, we recommend that periodic updates of the forecasts contained in this report be conducted so recent historical trends can be recognized and taken into account.

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1.0 Introduction

Low natural gas prices in conjunction with environmental regulations are driving retirements of coal-fired generation capacity and a shift towards more natural gas fired generation capacity. As the dependence on natural gas as a fuel for electric generation grows, there is a need to understand the ability of the natural gas infrastructure to reliably serve electric generation needs.

The Electric Reliability Council of Texas (ERCOT) commissioned Black & Veatch to perform a Gas Curtailment Risk Study in 2012¹ to evaluate the risk of natural gas supply disruptions to electric generating stations within the ERCOT administered portion of Texas over one, five and ten year periods. The study was intended to increase ERCOT's understanding of the risks of generation loss from gas supply curtailment in the future and to consider potential mitigation measures that ERCOT can pursue to reduce risks arising from these curtailments.

The current study has been commissioned by ERCOT to assess the long-term ability of the natural gas infrastructure to serve electric generation needs within the ERCOT service region between 2020 and 2030. Both studies are part of a larger long-term transmission planning effort undertaken by ERCOT and funded by the Department of Energy.²

2.0 Scope of Work

In this study, Black & Veatch reviews current and projected natural gas fired generation and the sufficiency of natural gas infrastructure to support power generation needs in ERCOT. Scenario analysis of extreme supply and demand scenarios are analyzed to assess the ability of the natural gas infrastructure to serve electric generation demand under more stressed market conditions. Black & Veatch also reviews potential locational constraints in adding natural gas infrastructure needed to support electric generation needs. The scope of this study is:

- A. Review of current natural gas-fired electric generation with ERCOT and current natural gas infrastructure supporting power generation needs within ERCOT
- B. Review of projected natural gas demand for electric generation in 2020-2030
- C. Assessment of sufficiency of natural gas infrastructure to serve electric generation needs
- D. Identification of locational constraints in adding natural gas infrastructure needed to support electric generation needs

¹ *Gas Curtailment Risk Study*, Prepared for ERCOT by Black & Veatch, March 2012.

² *ERCOT Interconnection Long-Term Transmission Analysis, 2012-2032*, ERCOT, Summer 2013.

3.0 Study Approach & Assumptions

3.1 FUNDAMENTAL MODEL

Black & Veatch utilized a fundamental market model³ as a basis to analyze the ERCOT and surrounding regions' natural gas market infrastructure. The network model nodes represent production regions, pipelines, storage facilities, and end-use customer groups. The fundamental model balances supply and demand from all the regions to find equilibrium prices and quantities that maximize producer profit and minimize consumer cost. Black & Veatch supports the fundamental model with a detailed database of proprietary and public sources that was modified to support the assumptions and scenarios for this study.

One of the challenges of understanding the risk of gas curtailment to electric generators within ERCOT is to determine the demand placed on the pipelines serving these electric generators by other sources – residential, commercial, and industrial demand within ERCOT's region as well as demand from outside ERCOT's region that are served by the same pipelines. By representing the entire natural gas infrastructure within North America, the fundamental model offers an efficient and effective methodology to model the impact of the total demand on the pipeline network from other sources within and outside of ERCOT's region. The fundamental model captures both interstate and intrastate pipeline segments.

Black & Veatch utilized the fundamental model to assess the constraints within the natural gas infrastructure, in responding to demand from the electric generation sector within ERCOT under the different defined scenarios. For each scenario, a corresponding estimate of demand, supply and any applicable scenario-specific infrastructure constraints were defined.

3.2 KEY ASSUMPTIONS

Black & Veatch utilized inputs from ERCOT's Long-Term Transmission Analysis⁴ to establish electric generation assumptions within ERCOT. At ERCOT's request, Black & Veatch utilized assumptions and outputs of the Business as Usual with All Tech Scenario, developed to be consistent with EIA's Annual Energy Outlook, and designed to simulate today's market conditions, extended 20 years into the future. For all other remaining North American markets, Black & Veatch utilized its 2013 Energy Market Perspective ("EMP") to derive assumptions on electric generation. EMP is a proprietary, integrated view of natural gas and power markets across North America, and the northern portion of Baja California, Mexico, that is electrically interconnected to the U.S. In order to arrive at this market view, Black & Veatch draws on a number of commercial data sources and supplements them with our own view on several key market drivers, for example, power plant capital costs, environmental and regulatory policy, fuel basin exploration and development costs, and gas pipeline expansion.

³ RBAC, Inc.'s GPCM® Natural Gas Market Forecasting System

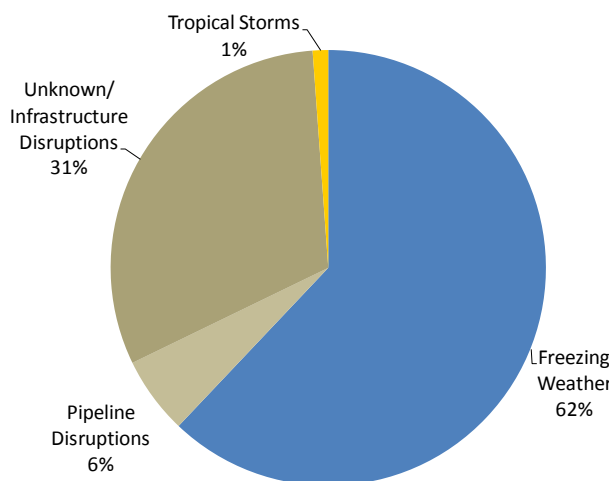
⁴ *ERCOT Interconnection Long-Term Transmission Analysis, 2012-2032*, ERCOT, Summer 2013.

3.3 SCENARIOS EXAMINED

Black & Veatch analyzed the sufficiency of natural gas infrastructure serving ERCOT's electric generation needs under a Base Case as well as different supply-demand scenarios. The scenarios examined were based

on an examination of historical records of gas supply curtailment during Black & Veatch's Gas Curtailment Risk Study for ERCOT from sources including ERCOT, the National Energy Technology Laboratory ("NETL") and the Railroad Commission of Texas ("TRRC"). As shown in Figure 1, the leading cause of historical gas supply curtailment incidents identified was freezing weather, with pipeline/infrastructure disruptions and tropical cyclones being inferred as having caused the other historical incidents of curtailment reviewed.

Figure 1: Historical Texas Gas Supply Curtailment Events



This study, therefore, examines the ability of the natural gas infrastructure to support electric generation needs within the ERCOT service region under extreme scenarios driven by these identified causes⁵:

- Cold weather
- Pipeline disruptions
- Tropical storms

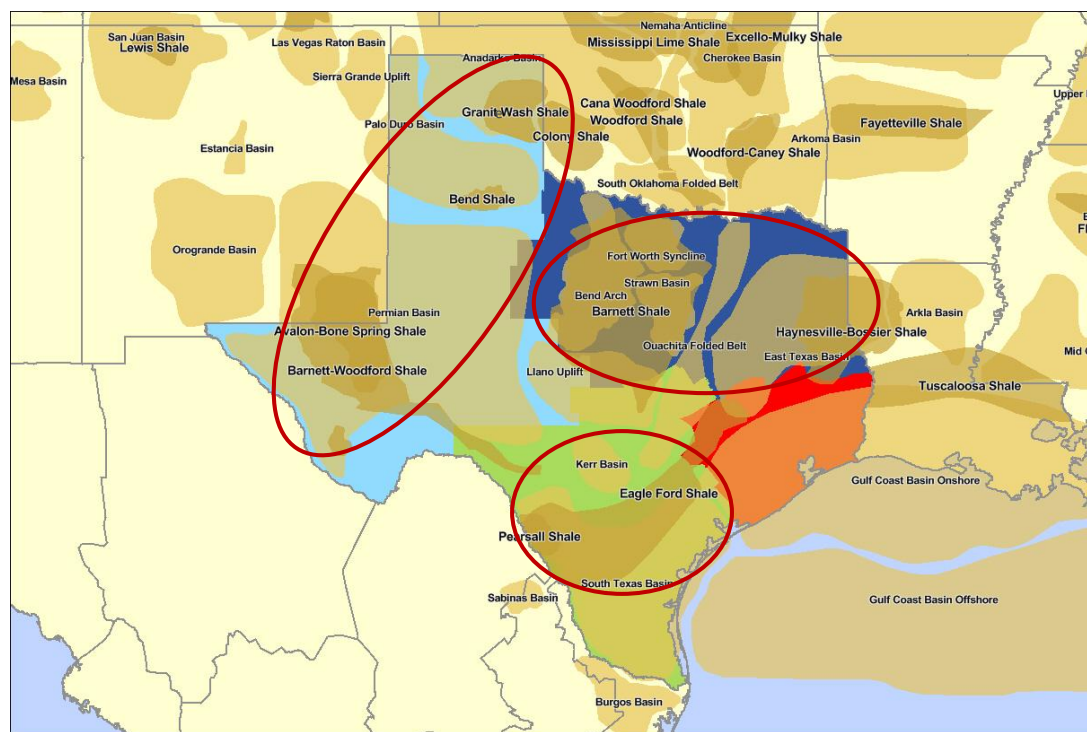
⁵ In addition to these scenarios, we also examined additional export demand from incremental LNG exports and pipeline exports to Mexico as a way of demonstrating the pipeline utilization and price impacts from these emerging demand sources. The results from these scenarios are included as an Appendix to the study.

4.0 Key Observations and Conclusions

Texas Enjoys Well Developed Natural Gas Infrastructure & Robust Production Growth Forecasts

Texas is a major natural gas producing state with production from conventional resources as well as unconventional natural gas resources from the Barnett Shale in the North, Granite Wash in the Panhandle region and Eagle Ford Shale in the South as shown in Figure 2. Pipelines located in the South zone of ERCOT also provide access to offshore Gulf of Mexico (“GOM”) production.

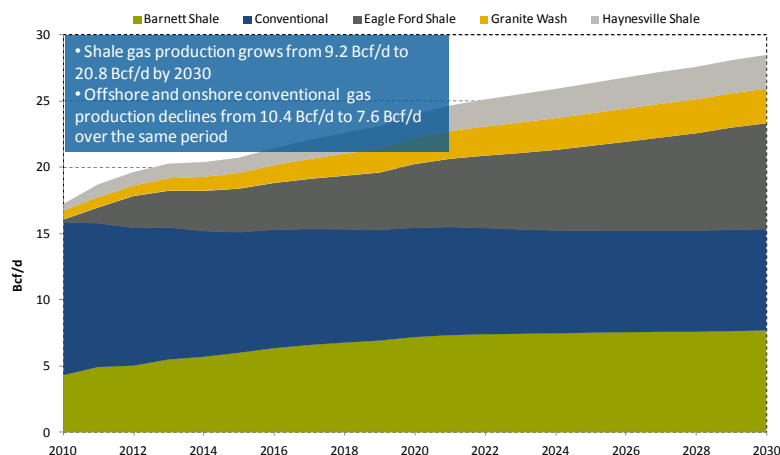
Figure 2: Texas Natural Gas Production Basins



Natural gas production in Texas is expected to grow by 8.5 billion cubic feet per day (“Bcf/d”), as shown in Figure 3 with growth in unconventional production expected to offset declines in conventional production. Multiple interstate and intrastate pipelines traverse Texas designed to move gas from production areas to consuming areas both within and outside Texas. Approximately 600 Bcf of natural gas storage capacity is located throughout the state to help manage seasonal demand fluctuations. The existing natural gas infrastructure is sufficient to meet the current needs from the power sector as evidenced by the relative stability of regional natural gas prices. For example, over the past three years, natural gas prices across Texas have averaged \$0.04/MMBtu below Henry Hub, a pricing point in Louisiana that is considered as reflecting overall natural gas market conditions in the U.S.

Shale gas production has created supply sources in regions that have historically been consuming markets and altered traditional pipeline flows. Emerging Marcellus and Utica Shale production growth in Pennsylvania and Ohio has reduced the demand for interstate natural gas pipeline flows from Texas to Northeast and Southeast markets. Reduced pipeline flows out of Texas are expected to make more interstate pipeline capacity available to the Texas market while reducing pipeline constraints.

Figure 3: Texas Natural Gas Production by Region



Natural Gas Fired Generation Capacity is Expected to Increase in ERCOT as well as Lower-48

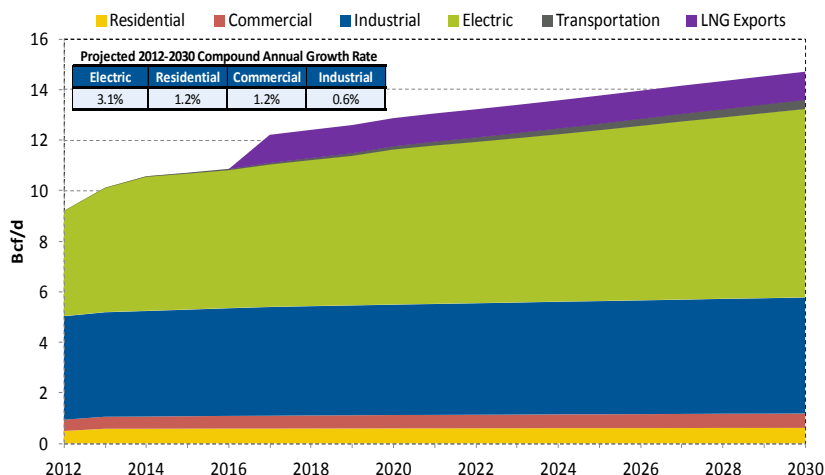
The study period between 2020 and 2030 is marked by expectations of significant growth in the use of natural gas for electric generation in North America driven by environmental policies and resulting coal-fired electric generation plant retirements and the cost competitiveness of natural gas technology compared to other fuel sources on a fixed and variable cost basis. ERCOT currently has 75,000 MW of total generation capacity, 43,000 MW of which is gas-fired generation capacity located in North, South, West and Houston zones. ERCOT's Long-Term Transmission Analysis indicates that total generation capacity within ERCOT is expected to increase to 92,000 MW by 2030 with gas-fired generation capacity additions within ERCOT expected to exceed 17,000 MW by 2030.

Lower-48 natural gas-fired generation capacity is expected to grow to represent 170,000 MW of the 290,000 MW of net generation capacity additions by 2030. This strong trend towards additional natural gas-fired generation capacity within ERCOT as well as the Lower-48 as a whole is expected to create new demand for natural gas and place greater strain on natural gas infrastructure.

Natural Gas Demand Growth in Texas is Expected to be Driven by Consumption from the Power Sector

Black & Veatch projects a moderate growth rate of 1.2% in residential and commercial demand for natural gas within Texas from 2013 through 2030. Industrial demand for natural gas is meanwhile expected to grow from 4.1 Bcf/d in 2013 to 4.6 Bcf/d by 2030 driven by low, competitive gas prices.

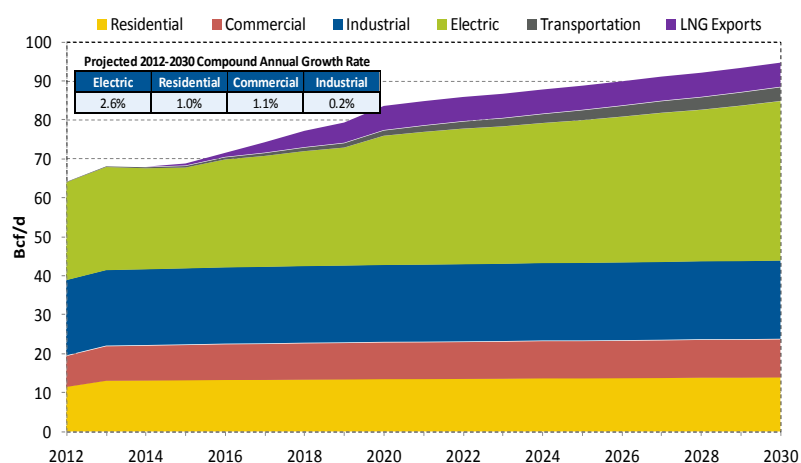
Figure 4: Texas Natural Gas Demand



Given modest demand growth in residential, commercial and industrial demand, electric generation is expected to be the biggest driver of natural gas demand growth, by far, both within Texas and the U.S. as a whole. Figure 5 shows that the projected increase in natural gas demand for electric generation within Texas from 4.2 Bcf/d in 2012 to 7.4 Bcf/d in 2030, at an annual growth rate of 3.1%. Power generation demand is expected to comprise 49% of total natural gas demand by 2030 within Texas.

A similar trend is projected for the Lower-48 as a whole with retirement of coal-fired generation capacity in the Midwest and in PJM creating key drivers for growth of natural gas demand for power generation as natural gas fired capacity helps meet load requirements in these regions. Figure 5 shows that the projected increase in natural gas demand for electric generation in the Lower 48 is expected to grow from 26.5 Bcf/d in 2013 to 41 Bcf/d in 2030, at an annual growth rate of 2.6%.

Figure 5: U.S. Lower 48 Natural Gas Demand



Power generation demand is expected to comprise 44% of total natural gas demand by 2030 in the Lower-48.

Natural Gas Infrastructure is Sufficient to Support Electric Generation in ERCOT during the Period of 2020 through 2030 under Base Case Conditions

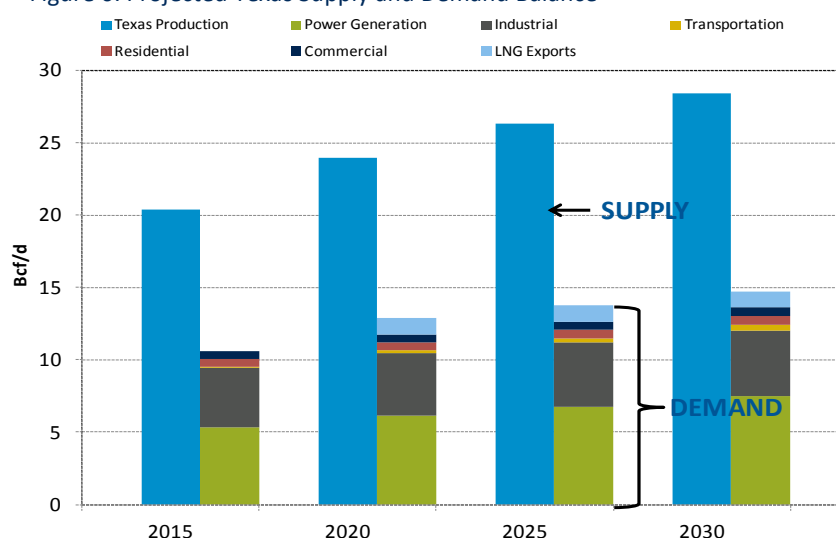
Black & Veatch's analysis shows that all four transmission zones in ERCOT will have access to sufficient natural gas infrastructure to meet their power generation needs under the Base Case scenario. Total natural gas production in Texas is projected to grow from 20 Bcf/d in 2013 to 28 Bcf/d in 2030, led by the fast growth from the Eagle Ford Shale in the South and steady output from the Barnett and Bossier Shales in the North. In aggregate, the South, West, and North transmission zones are expected to be able to export 12 Bcf/d of natural gas to Mexico, the Houston zone and downstream markets in the U.S. Southeast and Florida. Figure 6 illustrates regional production and total demand (including demand from all sectors and LNG export terminals) in ERCOT from 2015 to 2030.

Regional production in the South zone is expected to grow and indicate excess natural gas supplies of 5 Bcf/d by 2030 that can be exported via pipelines to Mexico and the Houston zone.

Similarly, the North and West zones have excess supply of 4 Bcf/d and 3 Bcf/d, respectively, by 2030.

Demand in the Houston zone relies upon imports from outside the zone. However, it has a total pipeline capacity of 6 Bcf/d from the South and 3 Bcf/d from the North, which far exceeds its 4.2 Bcf/d of local demand.

Figure 6: Projected Texas Supply and Demand Balance



Natural Gas Infrastructure is Sufficient to Support Electric Generation in ERCOT during the Period of 2020 through 2030 under Stress Scenarios

Black & Veatch tested the flexibility and adequacy of the natural gas infrastructure in Texas with extreme weather and supply conditions. Two extreme cold weather scenarios were examined to replicate low probability but plausible conditions: Cold Texas which examined the impact of extreme cold weather in Texas alone, and Cold Texas and Outside, which examined the impact of extreme cold weather in Texas as well as markets in the U.S. Northeast, Southeast and Midwest.

The extreme cold weather considered for each scenario assumed the cold end of average daily winter temperatures corresponding to the 95th percentile for each region; i.e., there is only a 5% probability that the temperature in the region will be lower than the assumed extreme cold temperature. For each scenario examined, a corresponding assumption on the increased demand for natural gas for heating purposes was developed based on historical data. The impact of freezing weather of simultaneously reducing natural gas supply due to production well freeze offs was also incorporated.

The Cold Texas scenario is designed to explore an extremely cold January that could cause residential, commercial and power sectors' demand for natural gas for heating within Texas to increase while natural gas supply simultaneously decreases due to production well freeze offs. The net impact on the Texas natural gas market in the Cold Texas scenario is 6 Bcf/d of combined demand increase and supply reduction.

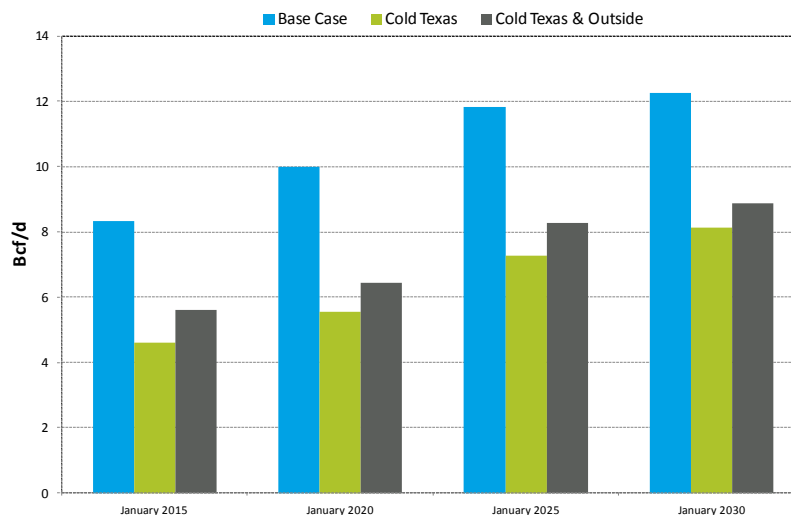
The Cold Texas and Cold Outside scenario with cold weather within Texas accompanied by cold weather in the U.S. Southeast, Northeast and Mid-Continent results in competing demand for natural gas within Texas as well as markets downstream of Texas. In all, a net incremental demand of 10 Bcf/d for natural gas due to colder weather was assumed in this stress scenario.

The assessment examined the supply-demand balance within these extreme cold weather scenarios. The supply-demand balance indicated that even under the extreme cold weather scenarios, the projected supply in Texas exceeds

regional demand for natural gas throughout the study period. Texas continues to export gas to other markets under the extreme cold weather scenarios, albeit at reduced levels as shown in Figure 7.

Market price responses offer another indicator of tightness in the natural gas market. An increase in overall price level is an indicator that more expensive supply is needed to meet the level of demand experienced in the market. An equally important indicator of regional constraint is basis, which is defined as the difference between regional natural gas prices and prices at the Henry Hub in Louisiana. When regional basis is high and separates from other markets, it provides an indication of constraints in the local market.

Figure 7: Projected Net Pipeline Exports from Texas



Under the Cold Texas scenario, overall price levels as well as basis in the Texas market rise. However, the increases in absolute price and basis are modest, indicating that the natural gas infrastructure is able to respond to and serve the incremental demand assumed.

Under the Cold Texas and Outside scenario, significant price impacts are observed across the U.S. while regional basis in Texas remains low indicating that Texas experiences relatively lower constraints in meeting the additional demand associated with the extreme cold weather scenario.

The next stress scenario examined the risk of disruption of natural gas supply to electric generators within ERCOT's service region caused by production shut-ins in the Gulf of Mexico driven by tropical cyclones. Historical data for the period 1981-2011 covering a total of 111 tropical cyclones, 25 of which made landfall in Texas was utilized to establish the level of production shut-in at 46% of the total Gulf of Mexico offshore production corresponding to a 95th percentile of risk (i.e., there is only a 5% chance of cyclone related production shut-ins impacting more than 46% of the offshore GOM production).

The primary result of the assessment is that there is minimal disruption of gas supply within Texas because much of Texas demand is served by local onshore production. Offshore production comprises only 2%-4% of total production in Texas. The loss of this production does not constrain access to supply for Texas consumers.

The study also examined the ability of the natural gas infrastructure to serve electric generators when pipeline disruptions occur. Based on the results of a survey of electric generators conducted as part of Black & Veatch's previous study for ERCOT, twenty-four electric generators are served by the Kinder Morgan Tejas Pipeline, which serves the largest number of electric generation facilities within ERCOT's service region. Our analysis reduced the capacity on this pipeline by 40% to examine the flexibility in the natural gas pipeline grid as well as in the electric generators' supply portfolios in the absence of this capacity.

Redundancy in the natural gas pipeline grid and in the transportation alternatives available to electric generators lead to increased utilization of other pipelines (primarily, Kinder Morgan Texas Pipeline in the scenario analyzed) that serve the gas demand of the customers stranded by failure of the original pipeline. Curtailment of natural gas supply was not observed in this scenario within the study period.

The study reveals that natural gas infrastructure, as represented within the fundamental model, appears to be adequate and does not act as a constraint during the stress scenarios examined. It should be noted however that localized and isolated incidents of constraints can occur on occasion at the utility or pipeline level. Although fundamental analysis indicates seamless transition in the market, it should be recognized that commercial arrangements and market inefficiencies could create challenges in the short-term to practically achieving these transitions.

Siting any New Natural Gas Infrastructure Needed will Involve Addressing Air Quality and Water Availability & Use Issues

Although no immediate constraints were identified in this study, increased production from Eagle Ford Shale in the ERCOT South zone as well as projections for strong demand growth in the ERCOT Houston zone are expected to drive higher pipeline utilization in these zones. This could create potential for increased constraints beyond the study period that may require additional natural gas infrastructure build.

At least three government agencies make authoritative decisions that affect development permits for natural gas infrastructure - Railroad Commission of Texas ("TRRC"), Texas Commission on Environmental Quality ("TCEQ") and the U.S. Environmental Protection Agency ("EPA"). At least two other government agencies can influence permit decisions affecting water or land use - Texas Water Development Board ("TWDB") and Texas Parks and Wildlife Department ("TPWD").

The main areas that need to be addressed to facilitate siting any new natural gas infrastructure needed are air quality, water availability and use and, to a lesser degree, endangered species. Air quality related to natural gas development is an issue for the Dallas, Houston and San Antonio regions with gas flaring becoming an emerging issue in the Eagle Ford region. Water availability has been recognized as an issue in the Dallas and San Antonio regions, so drought remains a concern. Endangered species (both plants and animals) are recognized by EPA/TPWD in all development areas.

Successful siting of any new natural gas infrastructure needed is expected to involve addressing these concerns. Texas has historically presented a conducive environment for the siting of energy infrastructure and this is expected to continue during the study period.

LONG-TERM ASSESSMENT OF NATURAL GAS INFRASTRUCTURE TO SERVE ELECTRIC GENERATION NEEDS WITHIN ERCOT: APPENDIX A

Prepared for

The Electric Reliability Council of Texas

OCTOBER 2013



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APPENDIX A

Black & Veatch, at the request of ERCOT, has summarized in this Appendix, the factors that cause gas supply disruptions due to freezing weather.

In 2012, Black & Veatch identified and reviewed 216 historical curtailment incidents from the various data sources. A key finding from review of those incidents is that the majority of historical curtailments to electric generators within ERCOT's service region during freezing weather appear to have been contractually permitted and triggered by a temperature threshold. A small number of cold-weather-related incidents were attributed to physical disruption of upstream supply or infrastructure. Figure 1 shows a fishbone diagram¹ outlining possible causes and effects leading to gas system failure related to freezing weather.

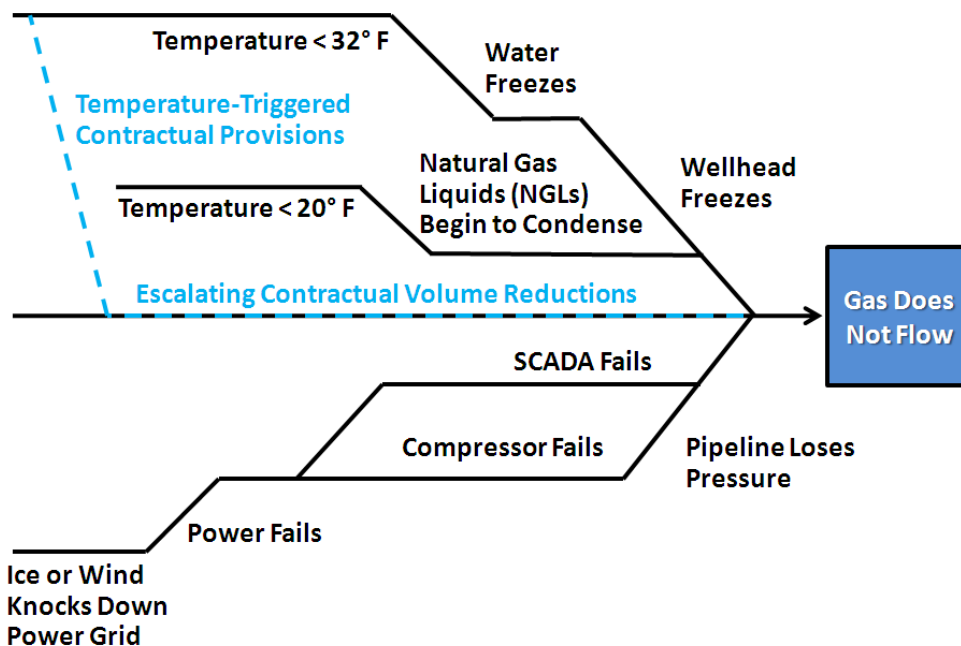


Figure 1 Fishbone diagram for possible freezing-weather causes of gas curtailments.

In a failure modes and effects analysis (FMEA), these are possible cause-and-effect strings that can affect gas-system performance, based on general historical experience. The precise cause-and-effect string is not always expressly published for every curtailment event. The potential factors leading to gas supply disruptions due to freezing weather are 1) freezing of onshore gas wellheads, 2) onshore power grids trip and pipelines lose pressure as gas compressors and/or Supervisory Control and Data Acquisition (SCADA) systems lose power

¹ A fishbone diagram (also known as an Ishikawa diagram) is a tool used to identify failure pathways in a failure mode and effects (FMEA) analysis. In the current study, fishbone diagrams are used to summarize how causative agents might lead to gas curtailments but without identifying likelihood of the alternative pathways.

and 3) contractual provisions with gas suppliers/transporters that allow curtailment of gas supply to power generators based on temperature thresholds.

Freezing weather can reduce gas flow at the wellhead through abnormal accumulations of liquids or ice which become problematic only at cold temperatures (Figure 2). The product stream from the well generally contains raw gas mixed with various amounts of water and oil condensates which must be promptly separated before the gas can be placed in a gathering-system pipeline and sent to a processing plant.

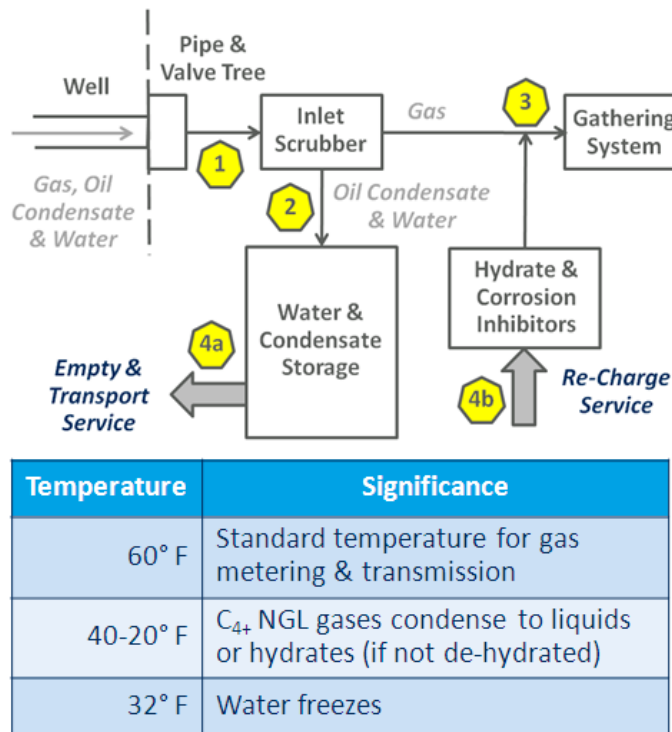


Figure 2. Freeze-off risks at an onshore natural gas wellhead.

Direct freeze-off effects include blockage of gas flow through (1) water frozen in the pipe-and-valve tree (“Christmas Tree”) atop the wellhead; (2) water frozen in the scrubber/separator which splits the product streams; (3) natural gas liquids (NGLs) or hydrates condensed before the gas can exit to the gathering system. Indirect freeze-off effects most commonly are breakdowns in the field services needed to keep the wellhead processes operational, including (4a) removal of separated water and oil condensate from limited onsite storage; (4b) replenishment of consumable chemicals (hydrate and corrosion inhibitors) which comprise the first line of gas treatment to prevent condensation in gathering pipelines. Modern wellhead systems include automated SCADA systems which normally are programmed to recognize empty/full tank conditions and shut-off product stream flow at the tree to prevent larger problems of spillage or line clogging. Interruptions to field services commonly are related to access problems created by inclement weather conditions.

Based on principles of thermodynamics, wind chill² increases the rate at which an object loses heat to the environment (Figure 3). Under influence of a strong wind, thermal conductive cooling is dominant whereas under calm conditions cooling is slower when more limited by thermal radiation. Nonetheless, the physical low temperature – not wind chill -- ultimately determines whether freezing occurs.

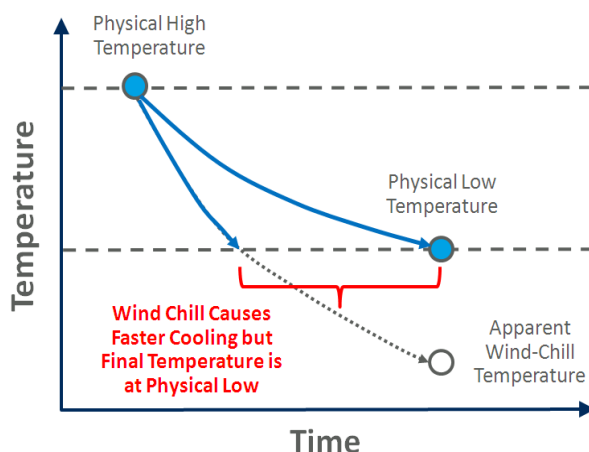


Figure 3. Significance of physical temperature relative to wind chill.

Freezing of water and condensation of NGLs are different problems which vary according to the composition of the product stream from each well. Associated gas which is produced from oil wells generally will flow greater proportions of water as the well ages. Therefore, older “conventional” gas wells tend to be at greater risk of water-related freeze-offs. “Unconventional” gas, such as from shales or other tight formations, will be at relatively greater risk of water-related freeze-offs if the wells are relatively young (i.e., completed within the last few months) because the flow-back of hydraulic-fracturing water probably still is in progress. NGL contents will be at risk for condensate formation both in conventional and unconventional wells and the risks will increase as the NGL contents increase. Therefore, risks of wellhead freeze-offs are expected to exist for all types of gas fields although specific risks for any specific field will depend on the types and ages of the wells in the field.

Black & Veatch utilized Barnett Shale data to develop the models for production loss because it was the largest gas resource with the longest baseline of production data in the 2011-2012 timeframe. Accordingly, empirical models for production losses during freezing-weather events were focused on the Barnett Shale data with the premise that the Barnett loss functions can be used as proxies for other gas fields which supply ERCOT. Our analysis also examined the production loss in the Haynesville, and Eagle Ford as a

² Wind chill is an apparent temperature calculated from wind speed and real physical temperature. It is a theoretical index designed to guide decisions about human exposure to cold environments. Wind chill is only defined for temperatures at or below 50° F and wind speeds above 3 mph. Bright sunshine may increase the wind chill temperature (i.e., make it less severe) by 10-18° F.

<http://www.nws.noaa.gov/om/windchill/>

comparison to Barnett Shale during the February 2011 freezing weather event. While there was some variation in production loss due to gas liquid content, the range in production loss during the event between the various plays was not significant.

Empirical production-loss curves were developed both for physical temperature and for wind chill using historical production and weather data (Figure 4). Both linear and non-linear regressions were calculated based on analysis of historical production losses versus historical weather for the six major freezing-weather events captured in the ERCOT Operator Logs (2002-2011; solid dots in Figure 4). Loss functions for wind chill are statistically stronger (higher R^2 values) but loss functions for physical temperature predict the highest production losses. Both for temperature- and wind chill-based functions, the non-linear models appear to be statically more robust (higher R^2 values). Therefore, to estimate “worst case” freeze-off losses, the model chosen was the non-linear Production Loss vs. Physical Low T(F) from the left-hand chart in Figure 4.

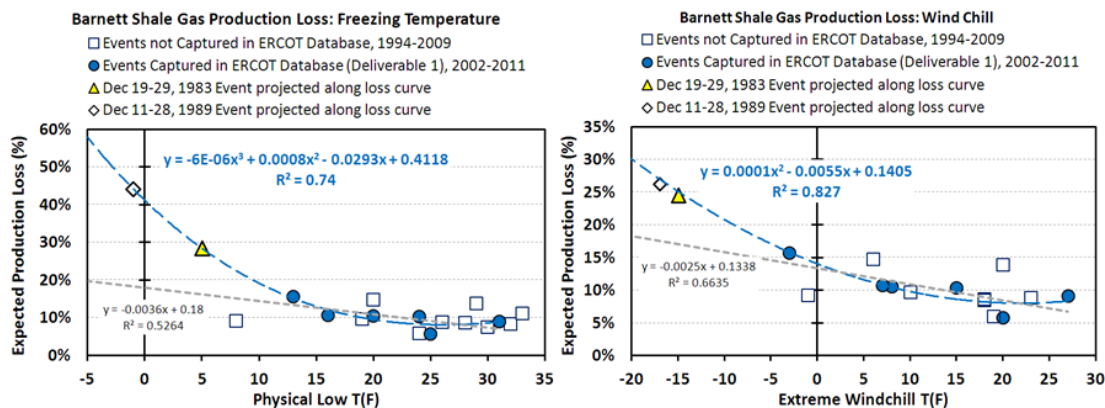


Figure 4. Empirical production-loss models based on production-weather data regressions.

In Figure 4, the fitted production-loss indicates a 10% production loss at temperatures between 20°-35°. Assuming low temperatures on the flat part of the curve and this 10% production loss, Texas production in 2015 would be about 17 Bcf/day and total Texas demand would be about 13 Bcf/day. The associated production loss would serve to reduce exports out of state, particularly with the supplies currently coming from the Marcellus and other plays out of state that reduce the dependence of other states on Texas pipeline exports.

In general, Gulf Coast fields (including Texas) do not routinely have freeze protection. With gas prices being low – and storage being full – the risk of 2-3 days of possible freeze-off every several years is a risk that Gulf Coast producers have been willing to take. It is a tradeoff between lost revenue from lost production vs. lost revenue from higher annual operating costs needed to freeze-protect individual wells.

BUILDING A WORLD OF DIFFERENCE

LONG-TERM ASSESSMENT OF NATURAL GAS INFRASTRUCTURE TO SERVE ELECTRIC GENERATION NEEDS WITHIN ERCOT

SUMMARY PRESENTATION

PREPARED FOR ERCOT

September 13, 2013

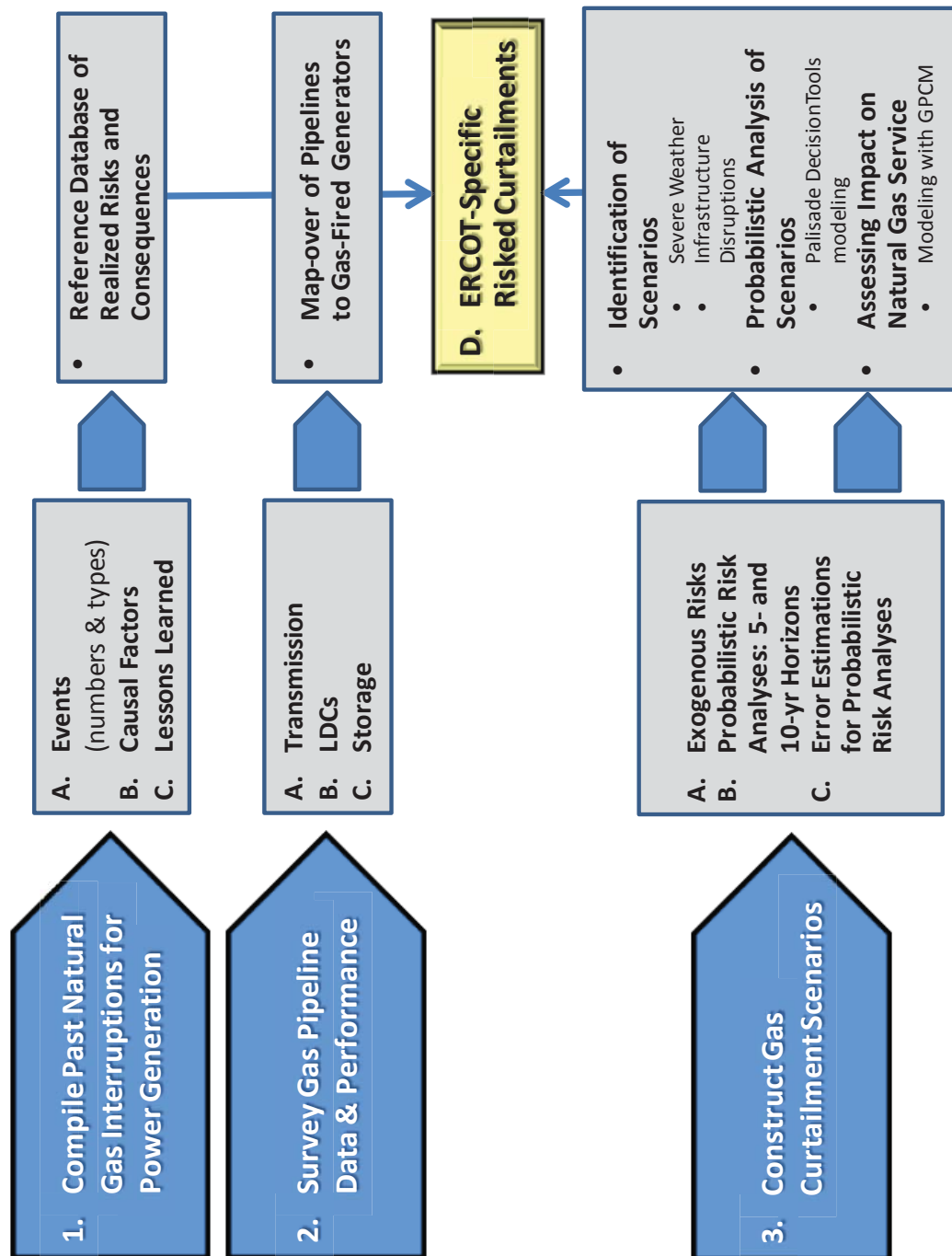
BACKGROUND OF STUDY

- ERCOT commissioned Black & Veatch to perform a Gas Curtailment Risk Study in 2012¹
- Study intended to increase ERCOT's understanding risks of generation loss from gas supply curtailment over 1, 5 and 10 years and potential ways to mitigate risks arising from curtailments
- Current study assesses the long-term ability of the natural gas infrastructure to serve electric generation needs within the ERCOT service region between 2020 and 2030
- Both studies are part of a larger long-term transmission planning effort undertaken by ERCOT and funded by the Department of Energy²

¹Gas Curtailment Risk Study, Prepared for ERCOT by Black & Veatch, March 2012.

²ERCOT Interconnection Long-Term Transmission Analysis, 2012-2032, ERCOT, Summer 2013.

OVERVIEW OF 2012 GAS CURTAILMENT RISK STUDY



PROJECT SCOPE – OVERVIEW

- Reviewed current and projected natural gas fired generation and sufficiency of natural gas infrastructure to support power generation needs in ERCOT
- Analysis of extreme supply and demand scenarios to stress test the ability of the natural gas infrastructure to serve electric generation
- Black & Veatch also reviewed potential regional constraints in adding natural gas infrastructure needed to support electric generation needs



PROJECT SCOPE BY TASK

Task A	<ul style="list-style-type: none"> Review of Current Natural Gas-Fired Generation and Infrastructure supporting Power Generation Needs Within ERCOT
Task B	<ul style="list-style-type: none"> Review of Projected Natural Gas Demand for Electric Generation in 2020-2030
Task C	<ul style="list-style-type: none"> Assessment of Sufficiency of Natural Gas Infrastructure to Serve Electric Generation Demand
Task D	<ul style="list-style-type: none"> Identification of Regional Constraints in Adding Natural Gas Infrastructure Needed to Support Electric Generation Needs

STUDY COMBINED ERCOT AND BLACK & VEATCH MARKET VIEWS

Key Assumption	Source
Electric Projections Within ERCOT	ERCOT’s Long-term Transmission Analysis – Business as Usual with All Tech Scenario
Current Electric Capacity within ERCOT	ERCOT CDR Report – May 2012
North American Electric Assumptions (Non- ERCOT)	Black & Veatch’s 2013 Energy Market Perspective
North American Natural Gas Demand and Supply	Black & Veatch’s 2013 Energy Market Perspective
Interstate and Intrastate Pipeline Infrastructure	Black & Veatch’s 2013 Energy Market Perspective

KEY OBSERVATIONS & CONCLUSIONS – SUMMARY

- Natural gas infrastructure serving ERCOT is expected to be adequate from 2020 to 2030
- Texas enjoys well developed natural gas infrastructure & robust production growth forecasts
- Natural gas infrastructure expected to be adequate under baseline or stress scenarios examined
- Commercial arrangements and market inefficiencies could create challenges in the short-term

KEY OBSERVATIONS & CONCLUSIONS – TASK A

- Sufficient natural gas infrastructure exists to meet ERCOT’s current power generation needs within ERCOT
- Natural gas production growth in Texas from unconventional shale production is expected to more than offset declines in conventional onshore and offshore supplies
- Projected natural gas pipeline and midstream infrastructure development in Texas follows emerging Eagle Ford Shale production and the need to access processing capacity to reach intra-state and Mexican export markets
- Sufficient existing natural gas storage capacity exists to meet the seasonal fluctuations of gas demand in Texas



KEY OBSERVATIONS & CONCLUSIONS – TASK B

- Robust demand growth in the power sector expected in ERCOT and Lower 48

Key Electric Component	ERCOT	Lower 48
Power Generation Capacity	75 GW in 2012 to 92 GW by 2030	966 GW in 2012 to 1,164 GW by 2030
Cumulative Natural Gas Capacity Additions 2017-2030	10,800 MW of CC and 6,800 CT	143,000 MW of CC and 27,000 MW of CT
Natural Gas Demand	3.1% CAGR	2.6% CAGR

- Natural gas demand from the residential, commercial and industrial sectors is expected to experience a moderate growth of 0.3% CAGR

KEY OBSERVATIONS & CONCLUSIONS – TASK C

- Black & Veatch analyzed the sufficiency of natural gas infrastructure to serve ERCOT’s electric generation needs under Base Case & different supply-demand stress scenarios

Scenario	Key Observations
Base Case	Sufficient natural gas infrastructure exists to meet the needs of power generation in each ERCOT transmission zone
Cold Texas	Even with additional gas demand in each ERCOT Zone, sufficient natural gas supply and available pipeline capacity exist
Cold Texas & Outside Markets	Sufficient natural gas supply and available pipeline capacity exist, albeit at higher prices to meet the additional gas demand from outside markets
Tropical Cyclone Supply Disruption	Limited impact on regional Texas market prices/basis Sufficient supply and pipeline infrastructure exists to meet the peak summer power generation gas demand
Pipeline Disruption	Limited impact on regional Texas market prices/basis



KEY OBSERVATIONS & CONCLUSIONS – TASK D

- Several government agencies make authoritative decisions that affect development permits for natural gas infrastructure
- Texas agencies can influence permit decisions affecting water or land use
- Air quality related to natural gas development is an issue for the Dallas, Houston and San Antonio regions
- Water availability has been recognized as an issue in the Dallas and San Antonio regions (Odessa not yet studied) and drought remains a concern

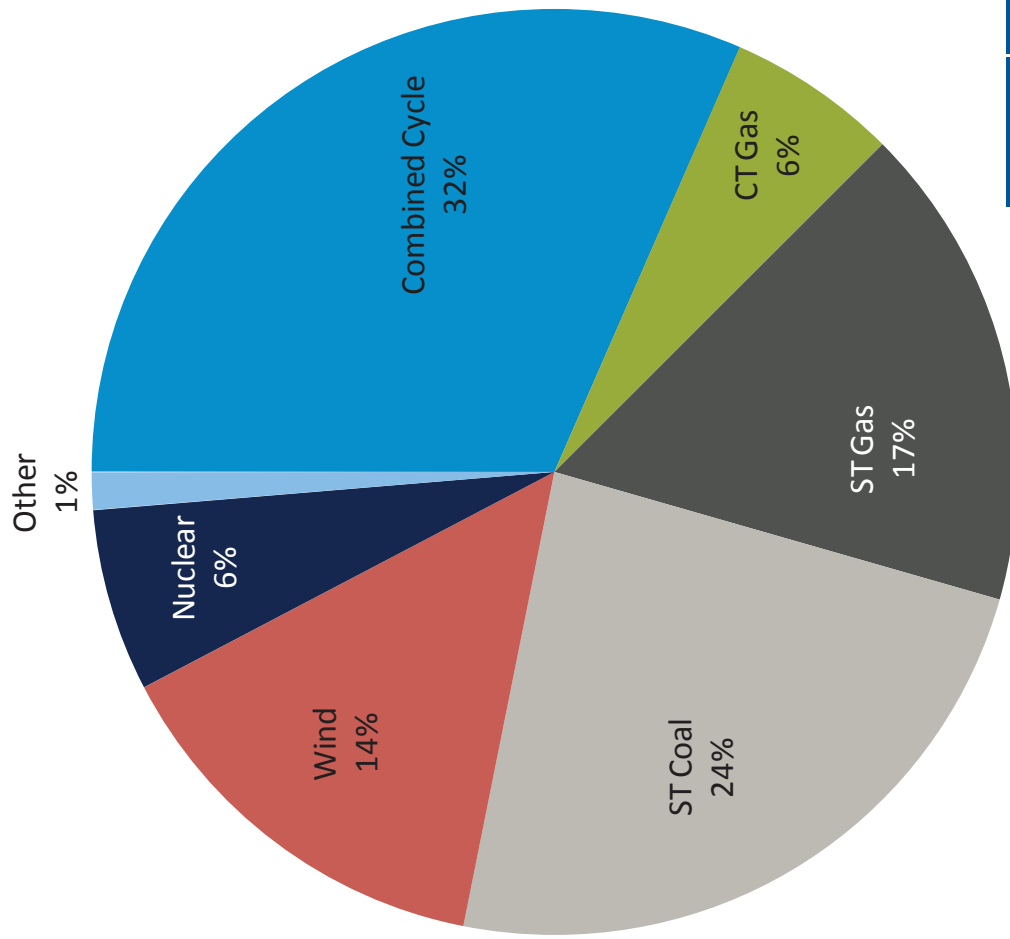
DISCUSSION OUTLINE

- A. **Review of Current Natural Gas-Fired Generation and Infrastructure supporting Power Generation Needs**
- B. Review of Projected Natural Gas Demand for Electric Generation (2020-2030)
- C. Assessment of sufficiency of Natural Gas Infrastructure to serve electric generation needs
- D. Identification of Regional Constraints in adding Natural Gas Infrastructure



KEY OBSERVATIONS – ERCOT GENERATION CAPACITY

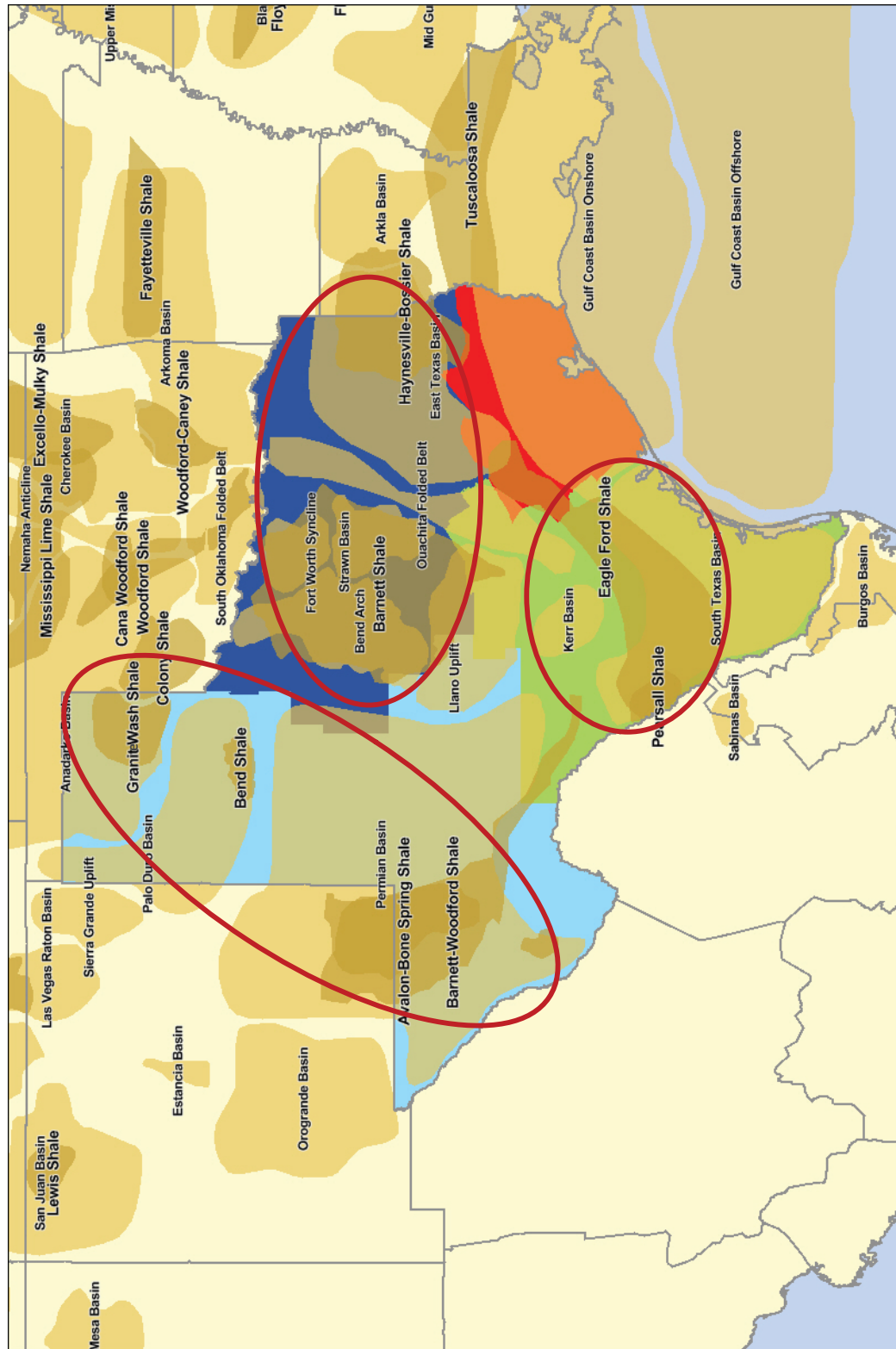
ERCOT - Summer Capacity (MW)



- Gas fired generation capacity makes up close to 50% of firm capacity across all ERCOT subregions
- Recent wind generation capacity additions have occurred in the South and West Zones
- The share of combustion turbine and combined cycle capacity expected to grow with additional steam turbine retirements

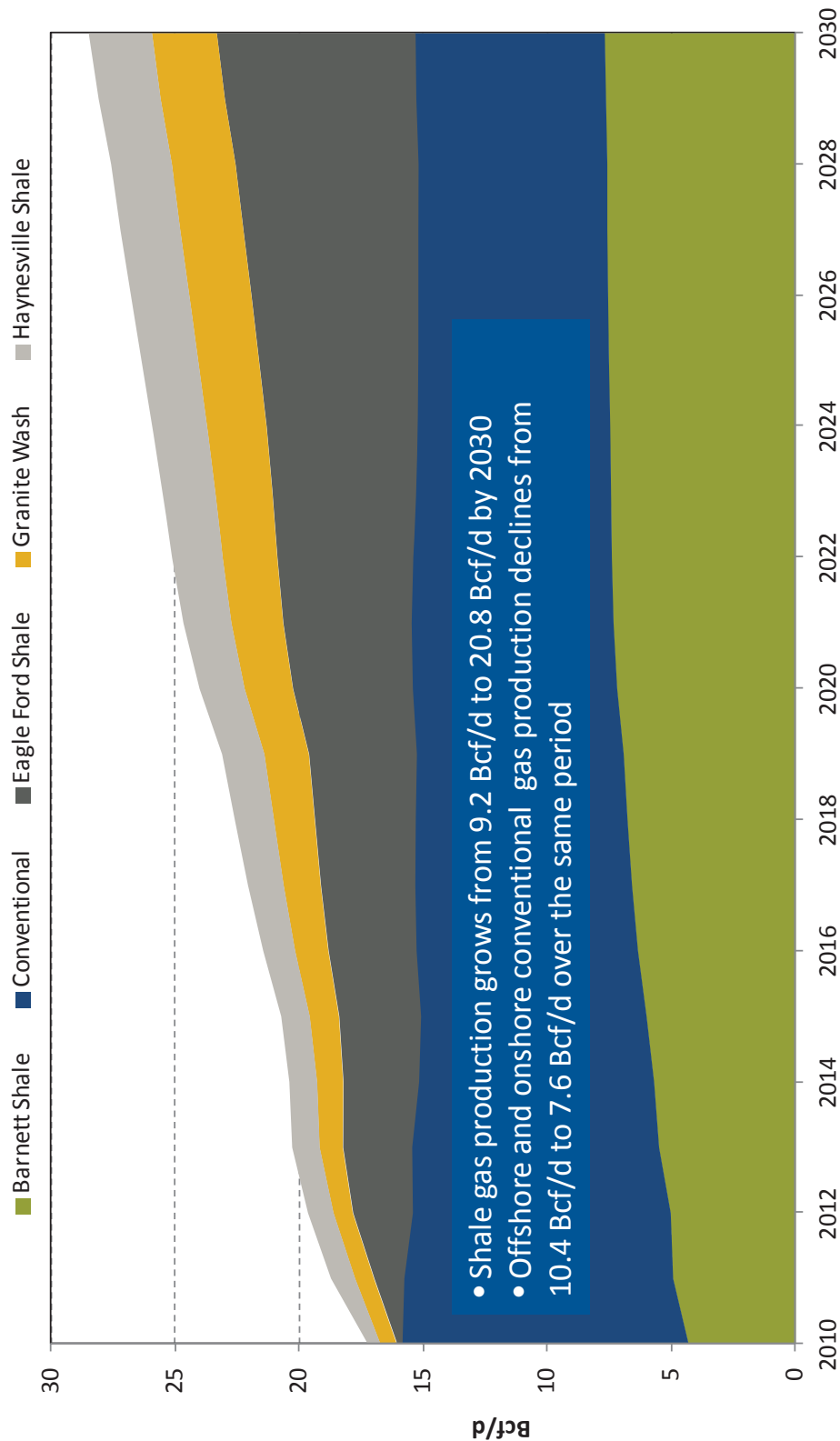
Source: ERCOT CDR Report – May 2012

TEXAS BENEFITS FROM MULTIPLE NATURAL GAS PRODUCTION AREAS SPREAD ACROSS THE STATE



TEXAS PRODUCTION IS EXPECTED TO GROW BY 8.5 BCF/D BY 2030

Historical and Projected Texas Production by Region 2010-2030

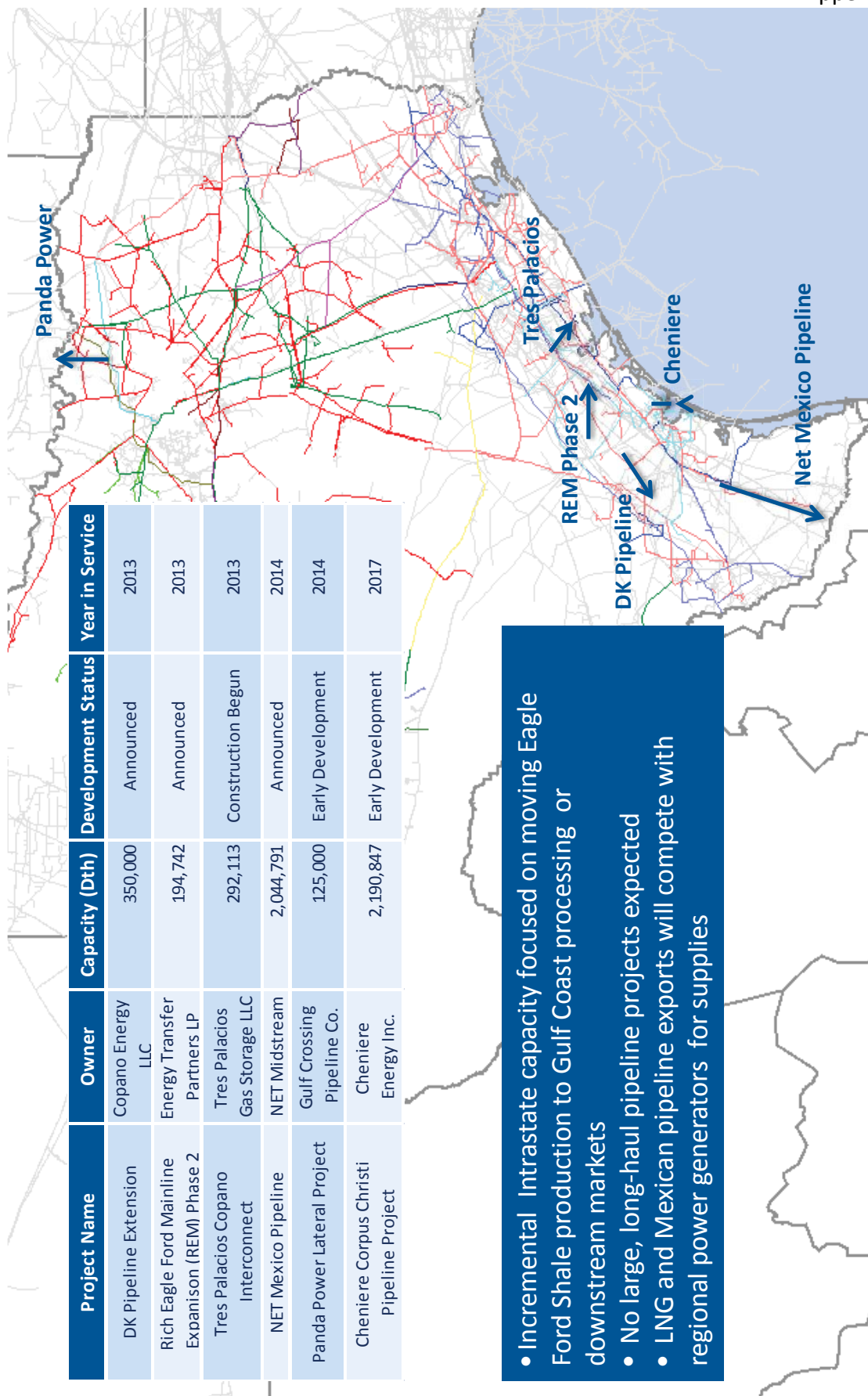


Source: Black & Veatch Energy Market Perspective

EAGLE FORD SHALE PRODUCTION STIMULATES SHORT-HAUL MIDSTREAM PIPELINE CAPACITY

Project Name	Owner	Capacity (Dth)	Development Status	Year in Service
DK Pipeline Extension	Copano Energy LLC	350,000	Announced	2013
Rich Eagle Ford Mainline Expansion (REM) Phase 2	Energy Transfer Partners LP	194,742	Announced	2013
Tres Palacios Copano Interconnect	Tres Palacios Gas Storage LLC	292,113	Construction Begun	2013
NET Mexico Pipeline	NET Midstream	2,044,791	Announced	2014
Panda Power Lateral Project	Gulf Crossing Pipeline Co.	125,000	Early Development	2014
Cheniere Corpus Christi Pipeline Project	Cheniere Energy Inc.	2,190,847	Early Development	2017

- Incremental Intrastate capacity focused on moving Eagle Ford Shale production to Gulf Coast processing or downstream markets
- No large, long-haul pipeline projects expected
- LNG and Mexican pipeline exports will compete with regional power generators for supplies



Source: Black & Veatch Energy Analysis



DISCUSSION OUTLINE

- A. Review of Current Natural Gas-Fired Generation and Infrastructure supporting Power Generation Needs
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- D. Identification of Regional Constraints in adding Natural Gas Infrastructure



ELECTRIC GENERATION ASSUMPTIONS

- **Black & Veatch utilized ERCOT's Long-Term Transmission Analysis* (ERCOT 2013 Long-Term Transmission Analysis) to establish electric generation assumptions within ERCOT**
 - At ERCOT's request, Black & Veatch utilized assumptions and outputs of the Business as Usual with All Tech Scenario, developed to be consistent with EIA's Annual Energy Outlook, and designed to simulate today's market conditions, extended 20 years into the future
- **For all other remaining North American markets, Black & Veatch utilized its 2013 Energy Market Perspective to derive assumptions on electric generation**
 - Our Energy Market Perspective is a proprietary view of electric generation load, power generation technology and fuel costs, and environmental regulations
 - Utilizes an integrated model approach to analyze the impact of various power generation fuels, policy drivers, and technologies on regional dispatch decisions and projected capacity retirements

**ERCOT Interconnection Long-Term Transmission Analysis, 2012-2032, ERCOT, Summer 2013.*



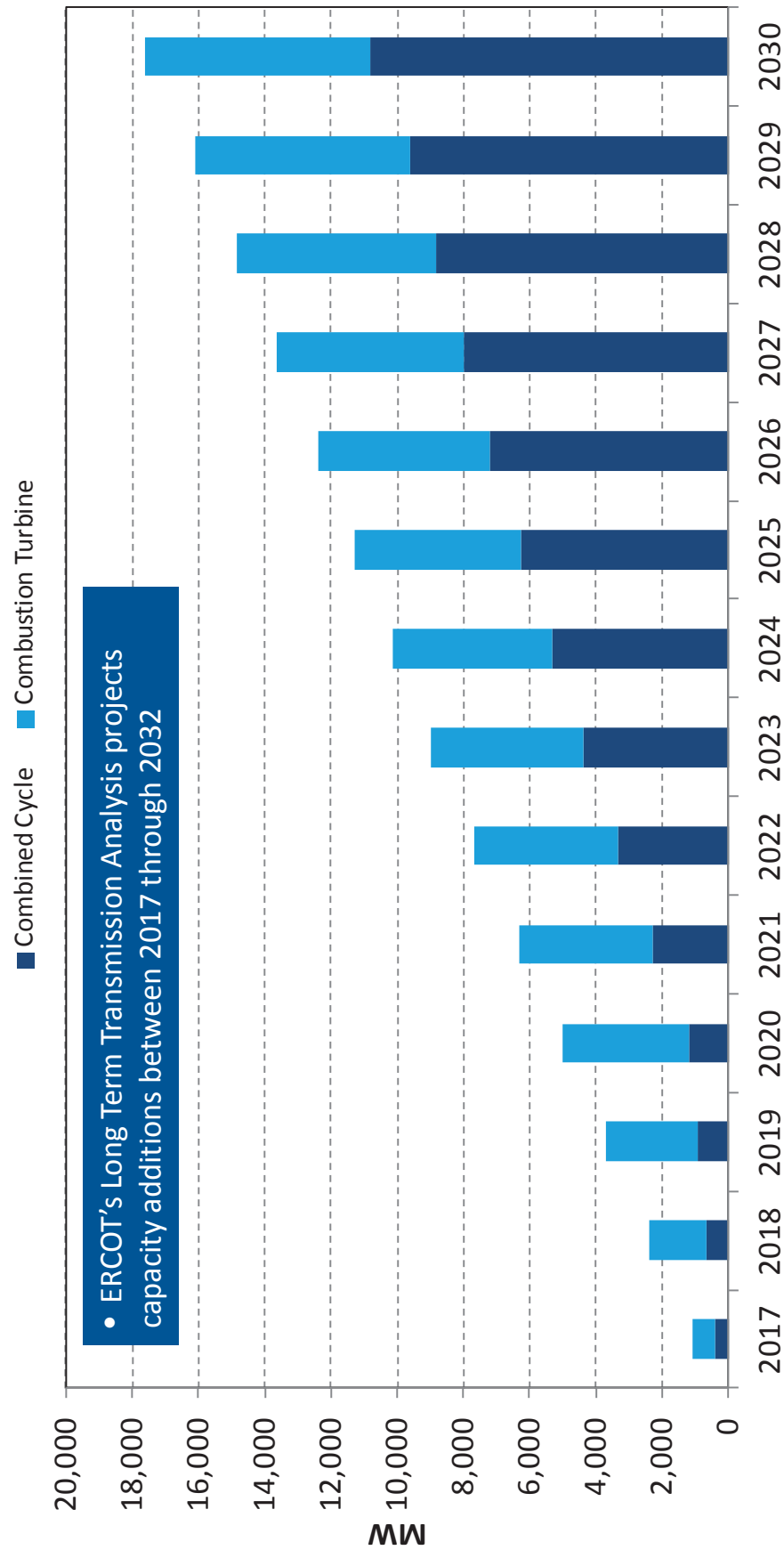
ELECTRIC GENERATION ASSUMPTIONS AND TRENDS

- **ERCOT – Business as Usual with All Tech**
 - Additional 17,600 MW of natural gas fired generation capacity from 2017 through 2030
 - 10,800 MW of Combined Cycle, 6,800 MW of Combustion Turbine selected from a set of resource technologies
 - No capacity retirements; expiration of the production tax credit results in no renewable capacity additions
 - Residential demand response of 2,200 MW and industrial demand response of 500 MW each year
- **Lower 48 – Black & Veatch’s Energy Market Perspective**
 - Additional 170,000 MW of natural gas fired generation capacity by 2030
 - 143,000 MW of combined cycle, 27,000 MW of combustion turbine capacity
 - 77,000 MW of coal retirements and 90,000 MW of renewable capacity additions by 2030
- **Overall, the retirement of coal generation capacity leads to the addition of G/H class base load gas fired combined cycle capacity, supplemented by renewables and combustion turbine capacity**



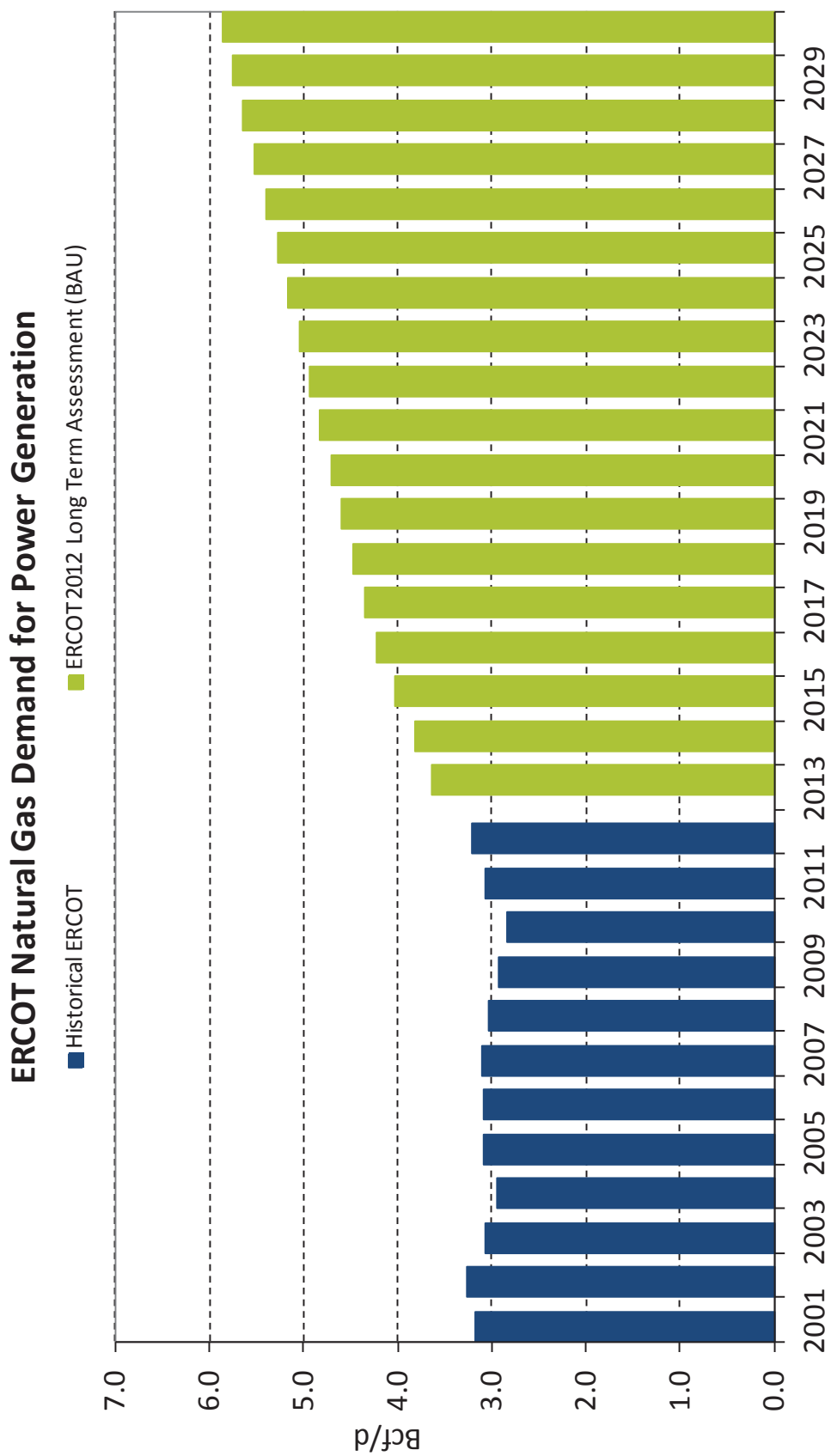
PROJECTED ERCOT GAS-FIRED GENERATION CAPACITY ADDITIONS EXCEED 17,000 MW BY 2030

Projected Cumulative ERCOT Generation Capacity Additions



Source: ERCOT 2013 Long-Term Transmission Analysis

ERCOT PROJECTS GAS DEMAND GROWTH FOR ELECTRIC GENERATION TO NEARLY DOUBLE BY 2030

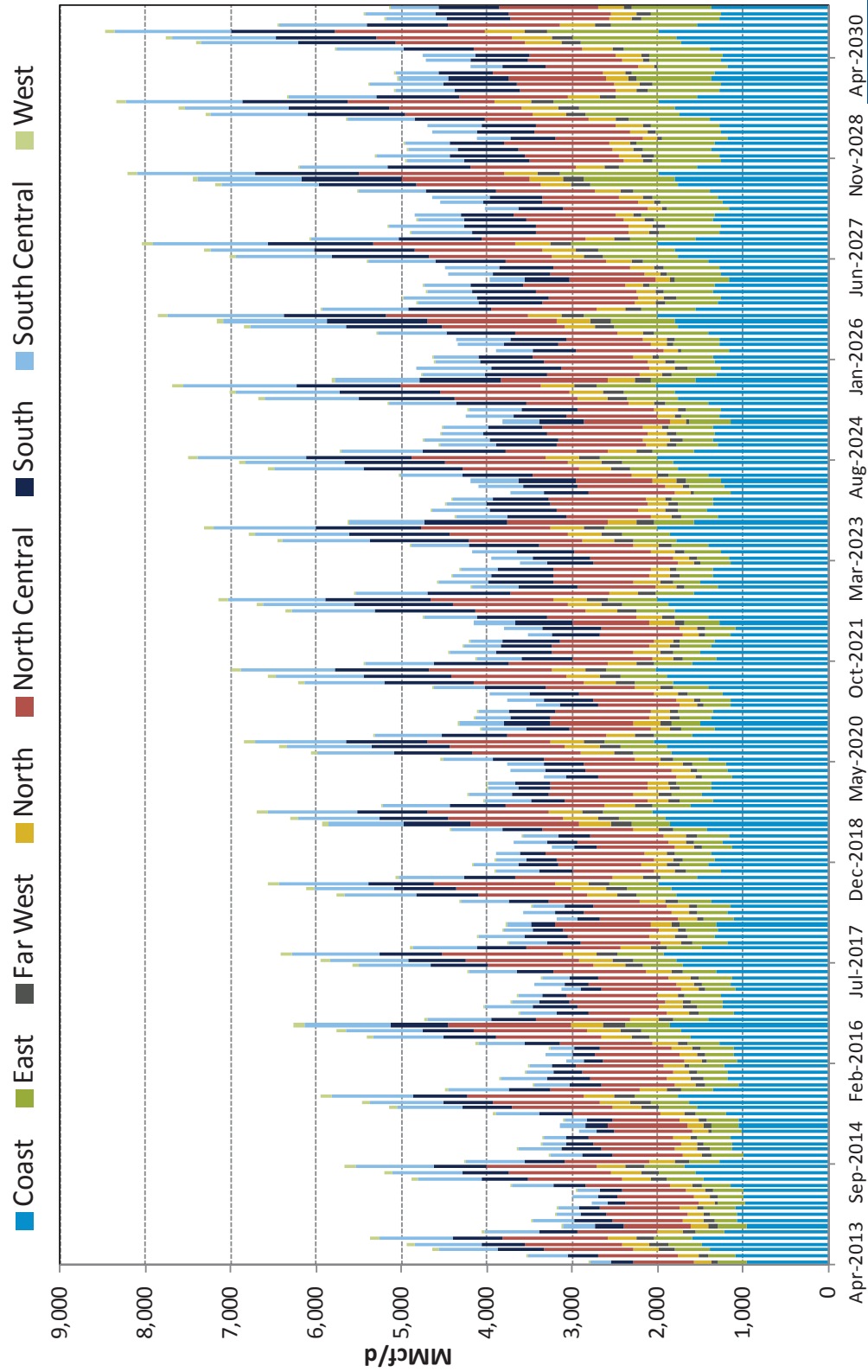


Source: ERCOT 2013 Long-Term Transmission Analysis



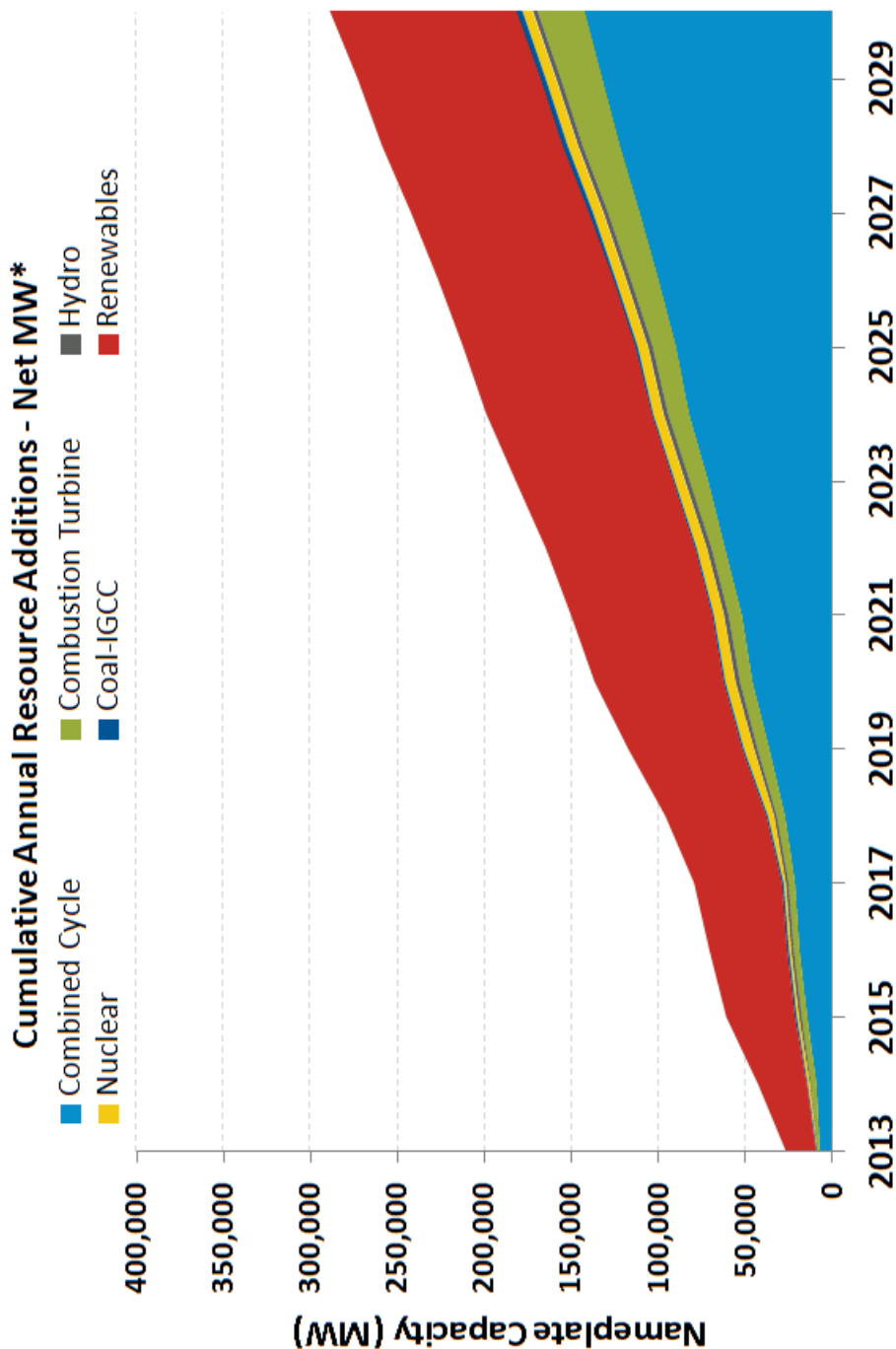
SIGNIFICANT SEASONAL VARIATION IN ERCOT GAS DEMAND FOR POWER GENERATION

Projected ERCOT Power Generation Demand by Weather Zone



Source: ERCOT 2013 Long-Term Transmission Analysis

PROJECTED LOWER 48, NON-ERCOT CUMULATIVE CAPACITY ADDITIONS, NEARLY 300,000 MW BY 2030

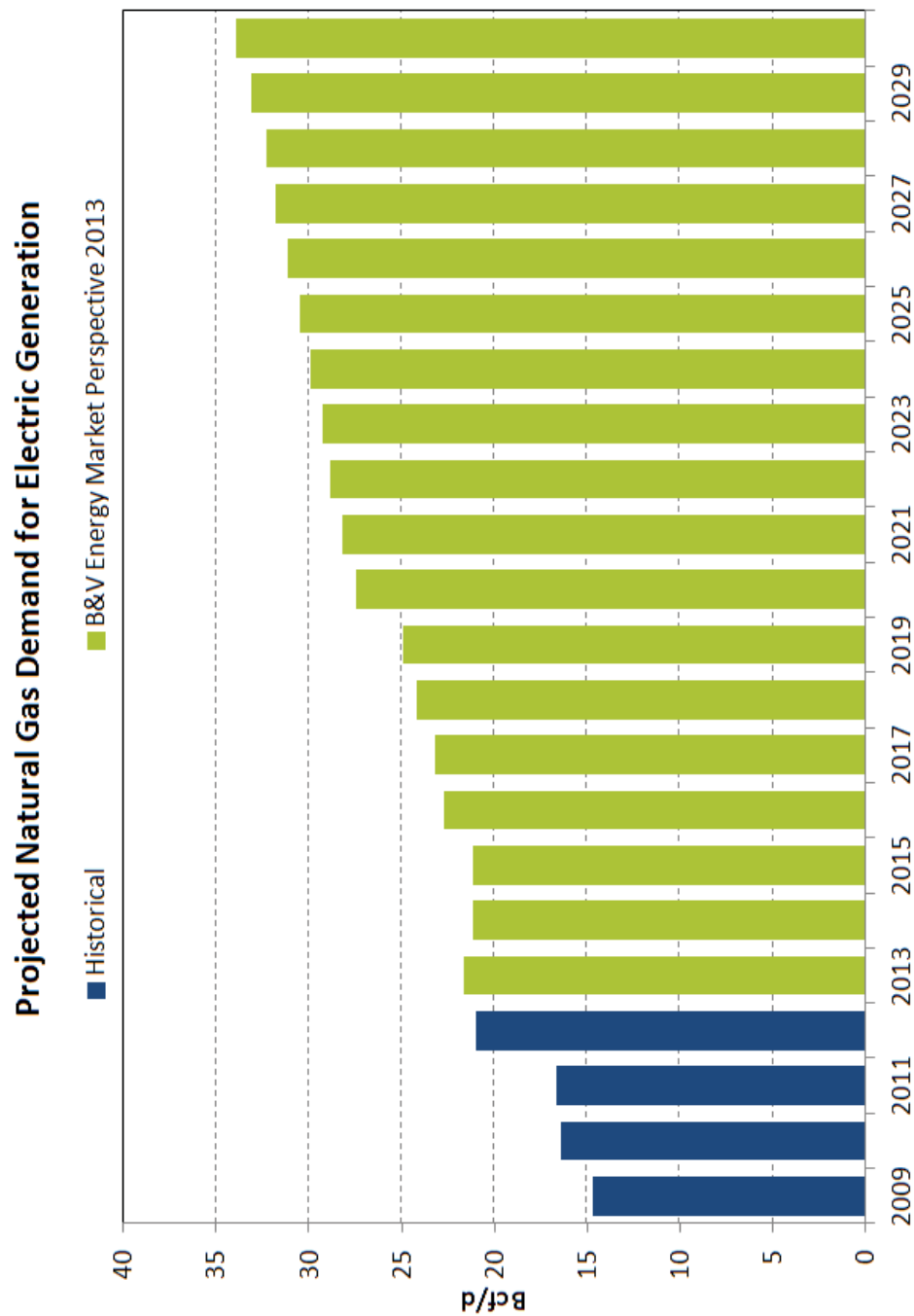


*Net capacity takes into account both additions and retirements

Source: B&V Energy Market Perspective 2013



LOWER 48, NON-ERCOT NATURAL GAS DEMAND FOR ELECTRIC GENERATION NEARLY 35 BCF/D BY 2030



Source: B&V Energy Market Perspective 2013

DISCUSSION OUTLINE

- A. Review of Current Natural Gas-Fired Generation and Infrastructure supporting Power Generation Needs
- B. Review of Projected Natural Gas Demand for Electric Generation (2020-2030)
- C. **Assessment of Sufficiency of Natural Gas Infrastructure to Serve Electric Generation Needs**
- D. Identification of Regional Constraints in Adding Natural Gas Infrastructure



SUMMARY FINDINGS – BASE CASE

- Under the Base Case, sufficient pipeline infrastructure exists to meet the needs of power generation in each ERCOT transmission zone
- Growth in Texas production is expected to support regional demand growth and maintain pipeline exports to Lower 48 markets
- Throughout the analysis period, close to 50% of Texas production will be consumed by markets outside of ERCOT
- Sufficient natural gas supply and capacity exist to serve gas demand for power generation in ERCOT

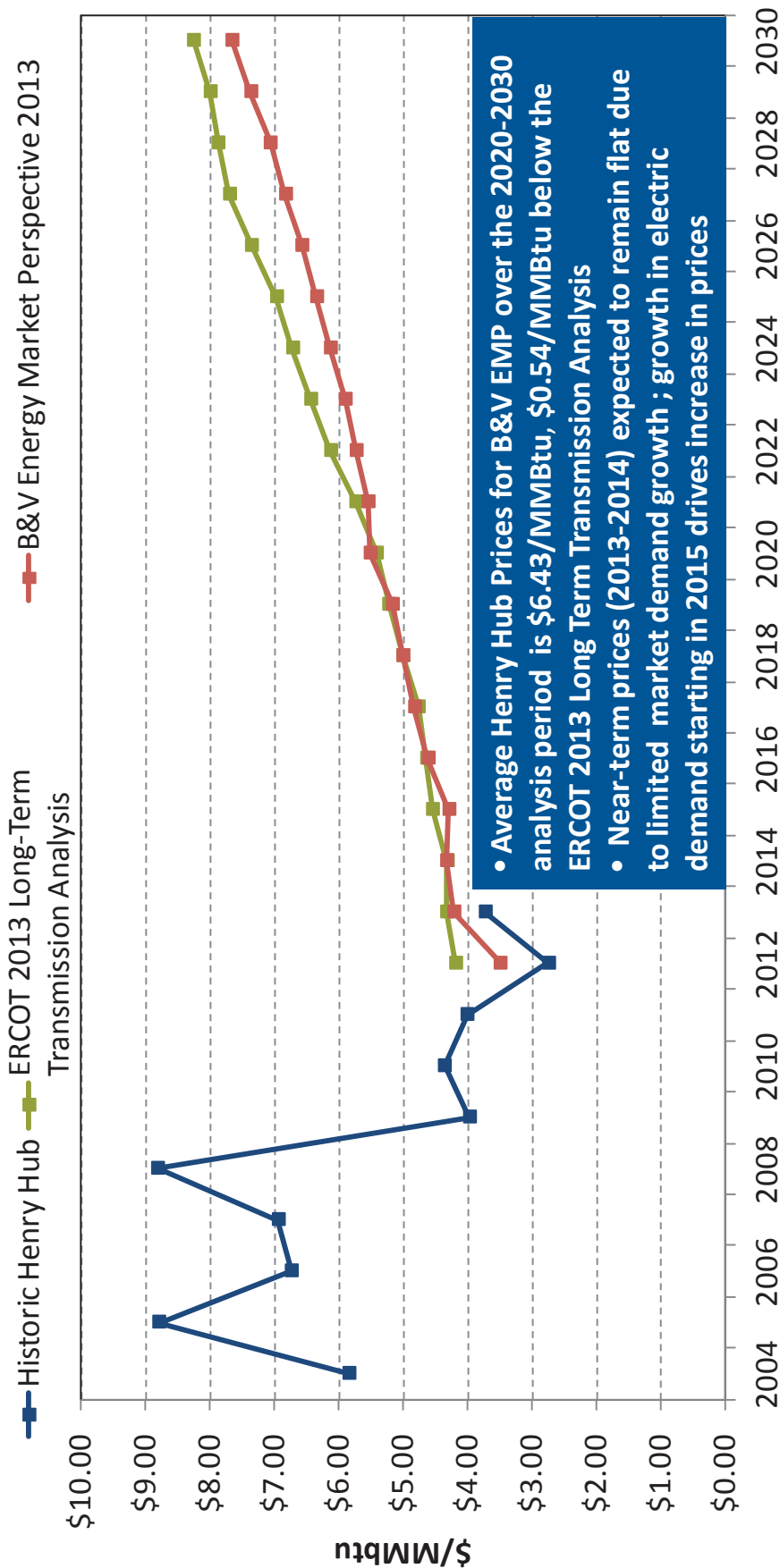
STUDY APPROACH

- The assessment examined the supply-demand balance for each ERCOT zone and entire ERCOT under the designed scenarios
 - The supply-demand balance indicates whether the projected supply in Texas exceeds regional demand for natural gas throughout the study period under the scenarios examined
- Market price responses offer another indicator of tightness in the natural gas market.
 - An increase in overall price level or regional basis is an indicator that additional higher cost supply is needed to meet the level of demand experienced in the market
 - The market price and basis response reflects the integrated nature of the North America natural gas market



B&V'S PROJECTED HENRY HUB PRICE RISES FROM \$5.00 TO \$8.00/MMBTU OVER THE ANALYSIS PERIOD

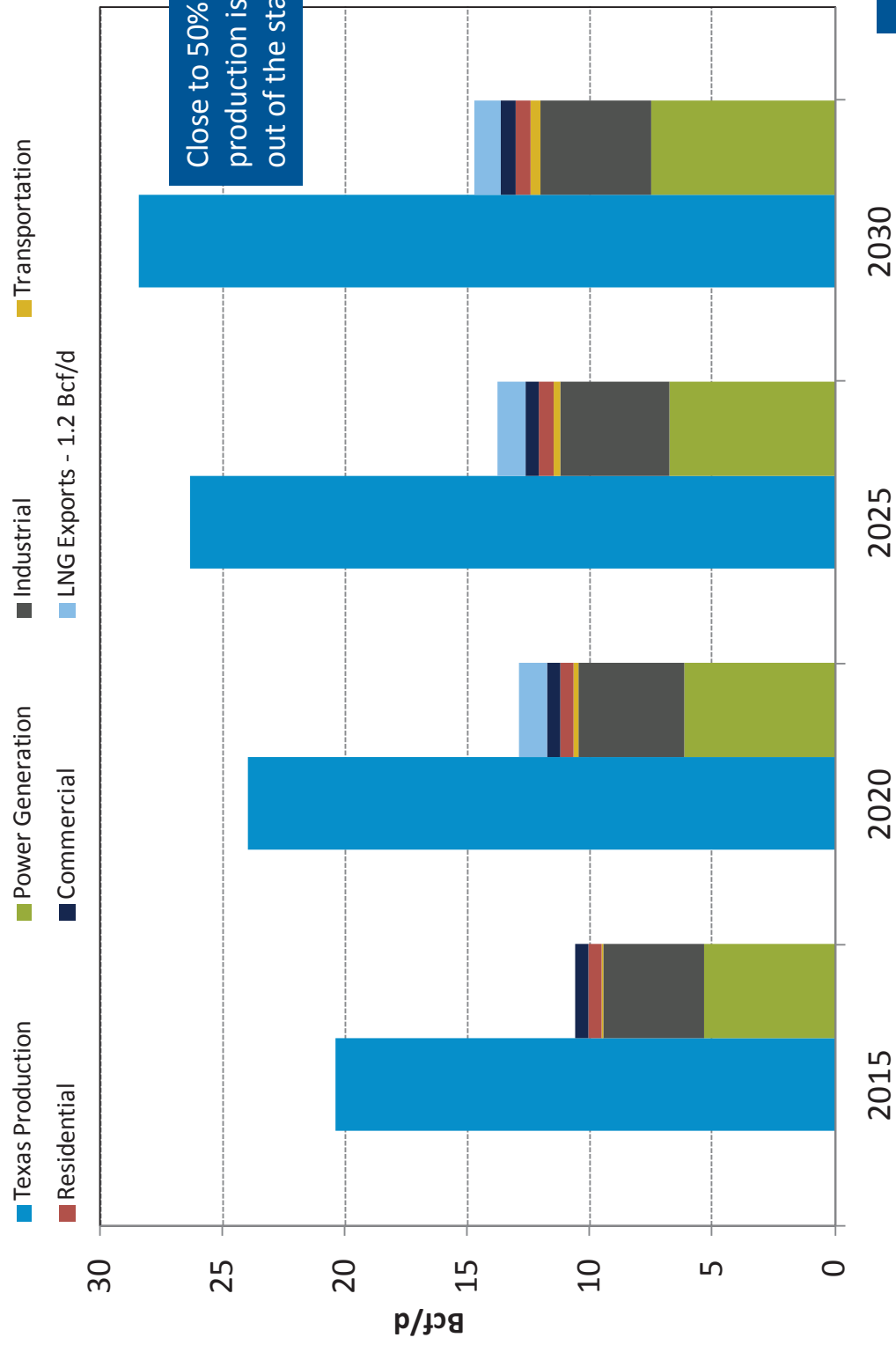
Comparison of Henry Hub Natural Gas Prices



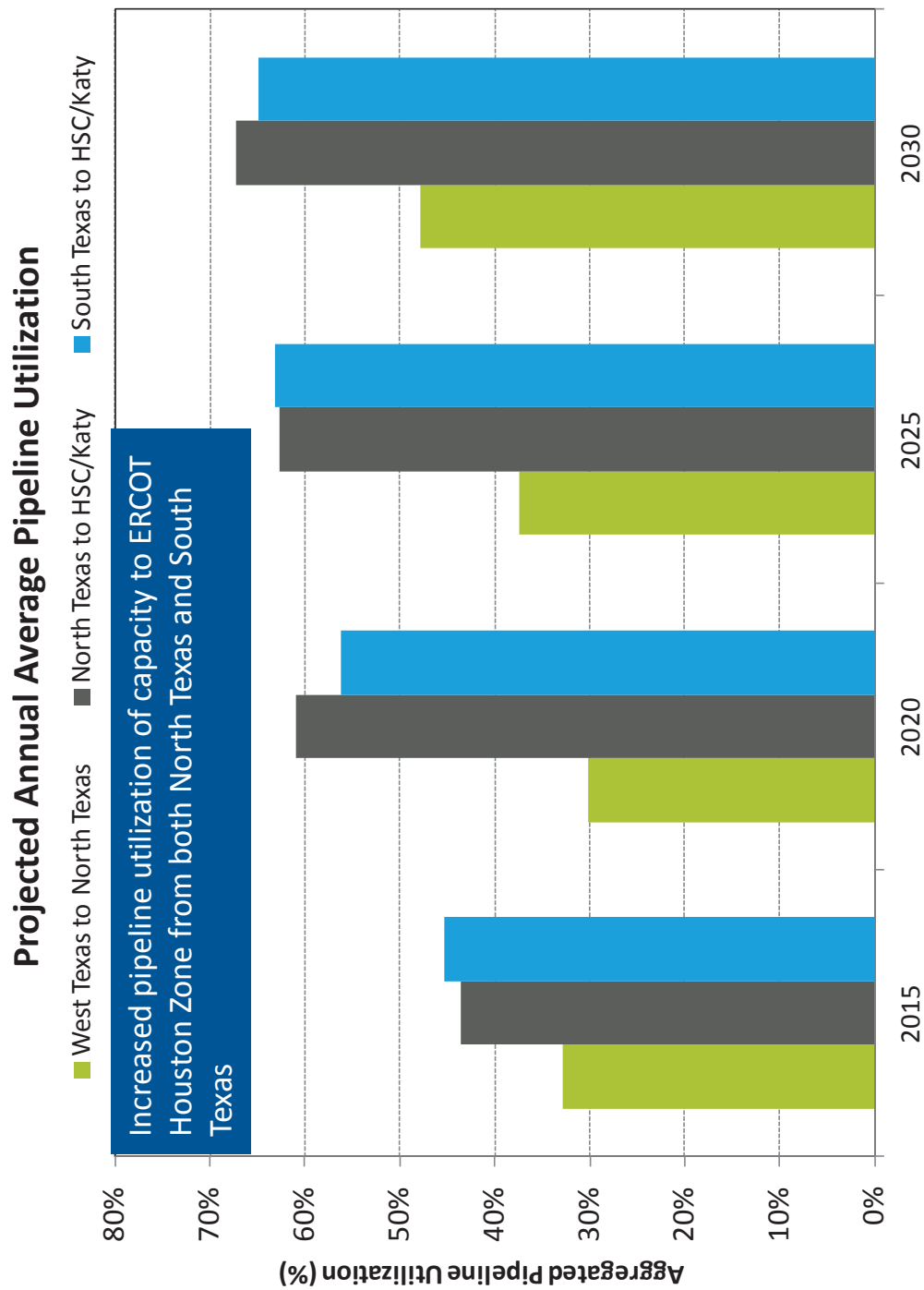
Source: ERCOT 2013 Long-Term Transmission Analysis, Black & Veatch Energy Market Perspective

PROJECTED TEXAS PRODUCTION GROWTH SUPPORTS REGIONAL DEMAND AND EXPORTS

Projected Texas Supply and Demand Balance

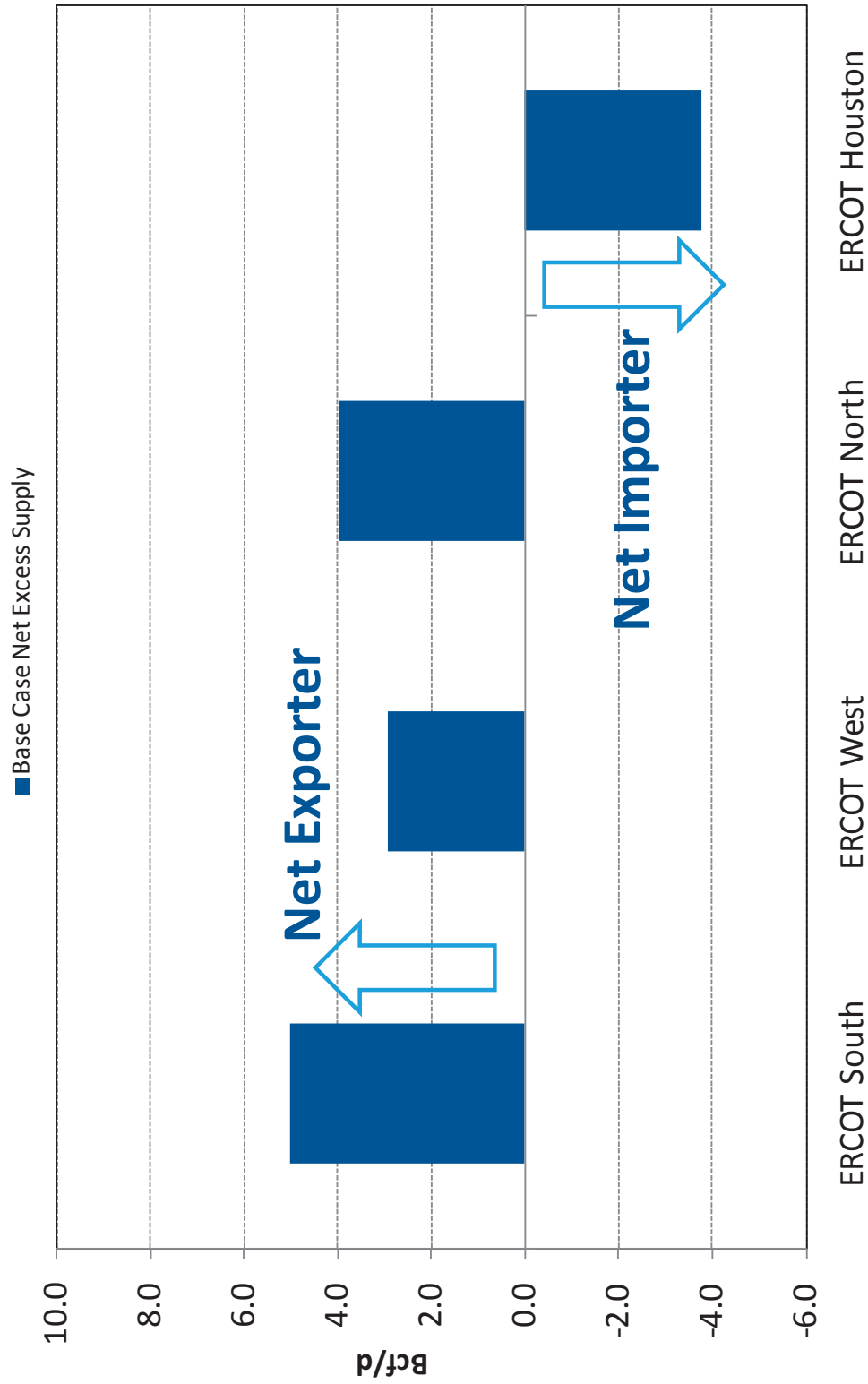


PIPELINE UTILIZATION INCREASES TO SUPPORT TEXAS DEMAND GROWTH AND EXPORTS



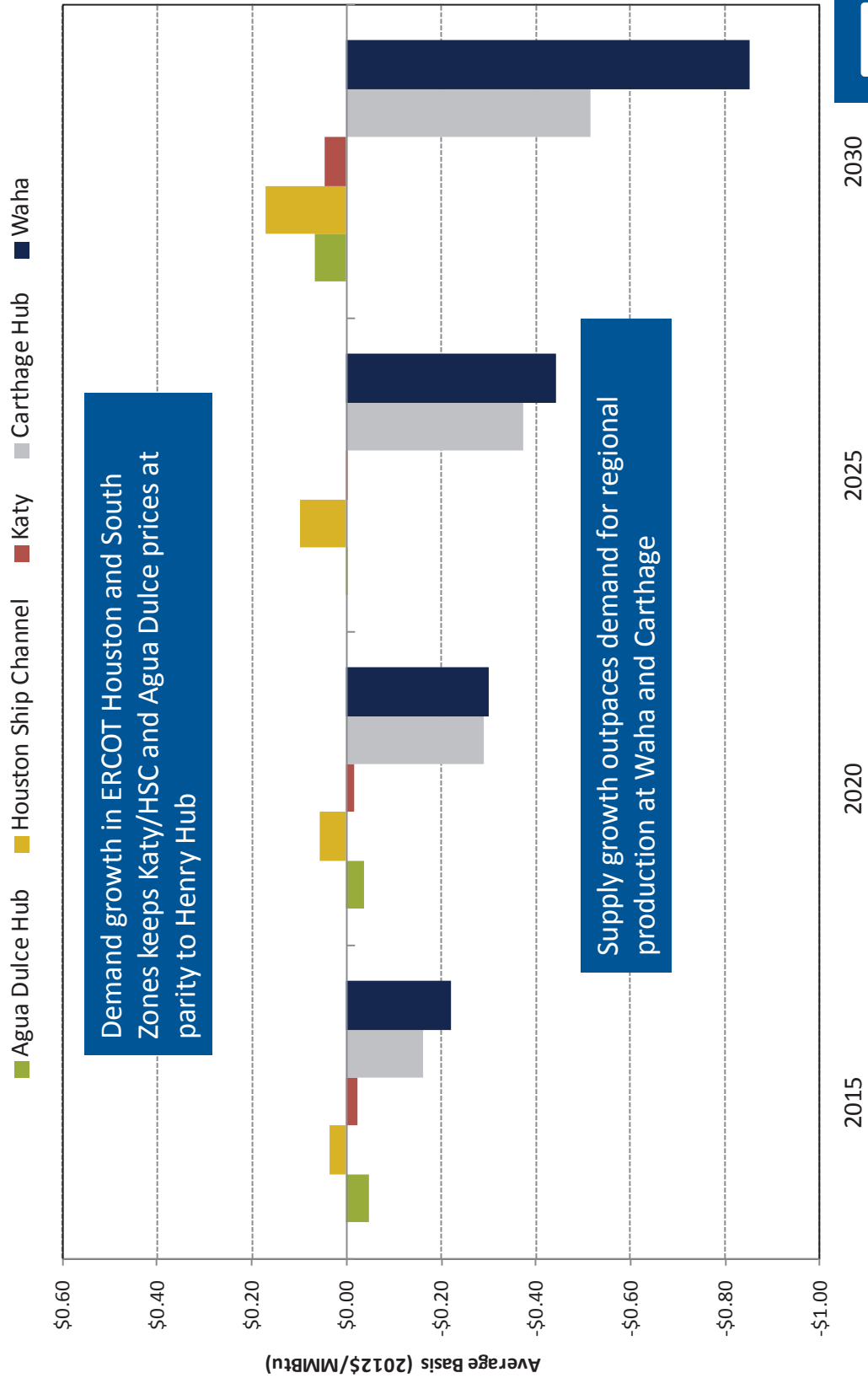
ERCOT HOUSTON IS THE ONLY ZONE WITH NET IMPORT NEEDS

Projected Supply and Demand Balance Across Scenarios- 2030



TEXAS MARKET AREA PRICES EXPECTED TO REMAIN LOW, TIED WITH HENRY HUB

Projected Annual Average Basis - Texas Markets



SUPPLY AND DEMAND STRESS TEST SCENARIOS DRIVEN BY GAS CURTAILMENT RISK STUDY

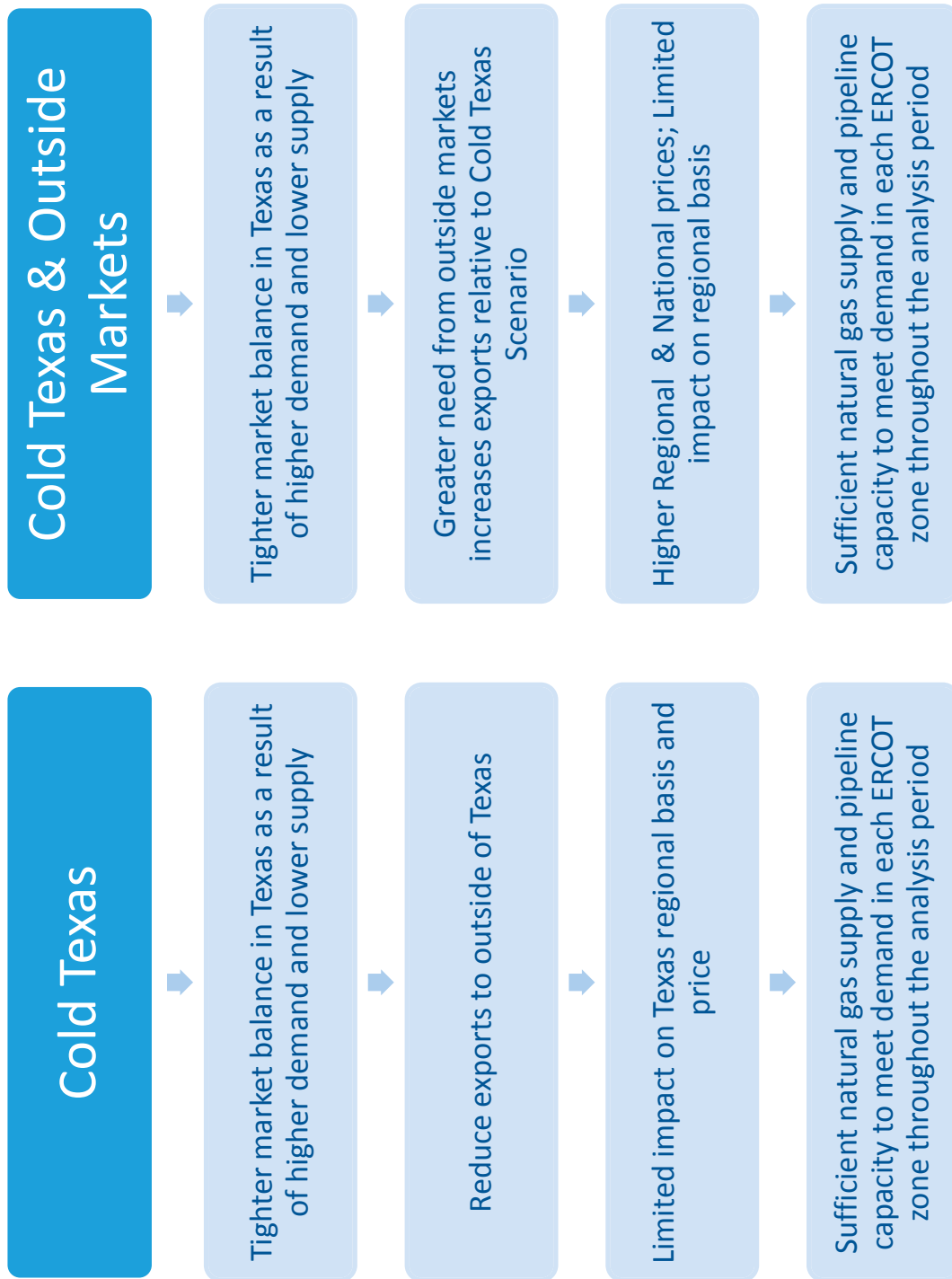
- Black & Veatch's Gas Curtailment Risk Study in 2012 reviewed various data sources to identify generation loss due to natural gas curtailments
- Historical records show that leading causes of historical gas supply curtailment incidents in ERCOT were due to:
 - Winter storms/Freezes
 - Tropical cyclones
 - Pipeline failures
- This study examines the ability of the natural gas infrastructure to serve electric generation needs within ERCOT under extreme scenarios driven by these identified causes



SCENARIO DESCRIPTIONS

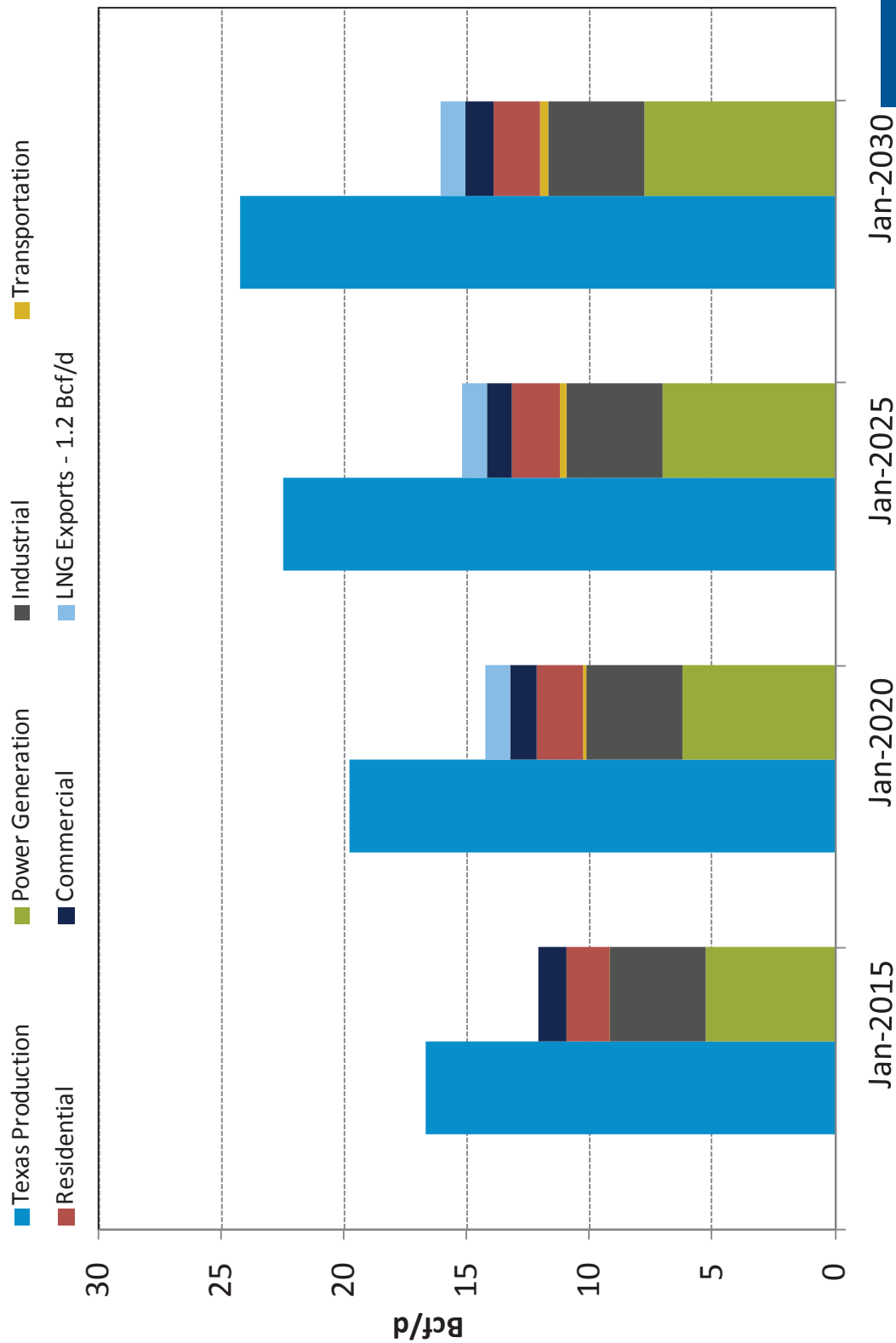
Scenario	Description
Cold Texas	Higher residential, commercial and power generation demand with some onshore production loss due to well freeze-offs
Cold Texas & Outside Markets	Same as Cold Texas, with higher residential and commercial demand in key export markets in Midwest, Northeast and Southeast markets
Tropical Cyclone Supply Disruption	A 46% reduction of offshore GOM production during peak summer month
Pipeline Disruption	A 40% reduction of pipeline capacity in a pipeline segment in the ERCOT Houston zone

SUMMARY FINDINGS – COLD TEXAS AND COLD TEXAS & OUTSIDE MARKETS



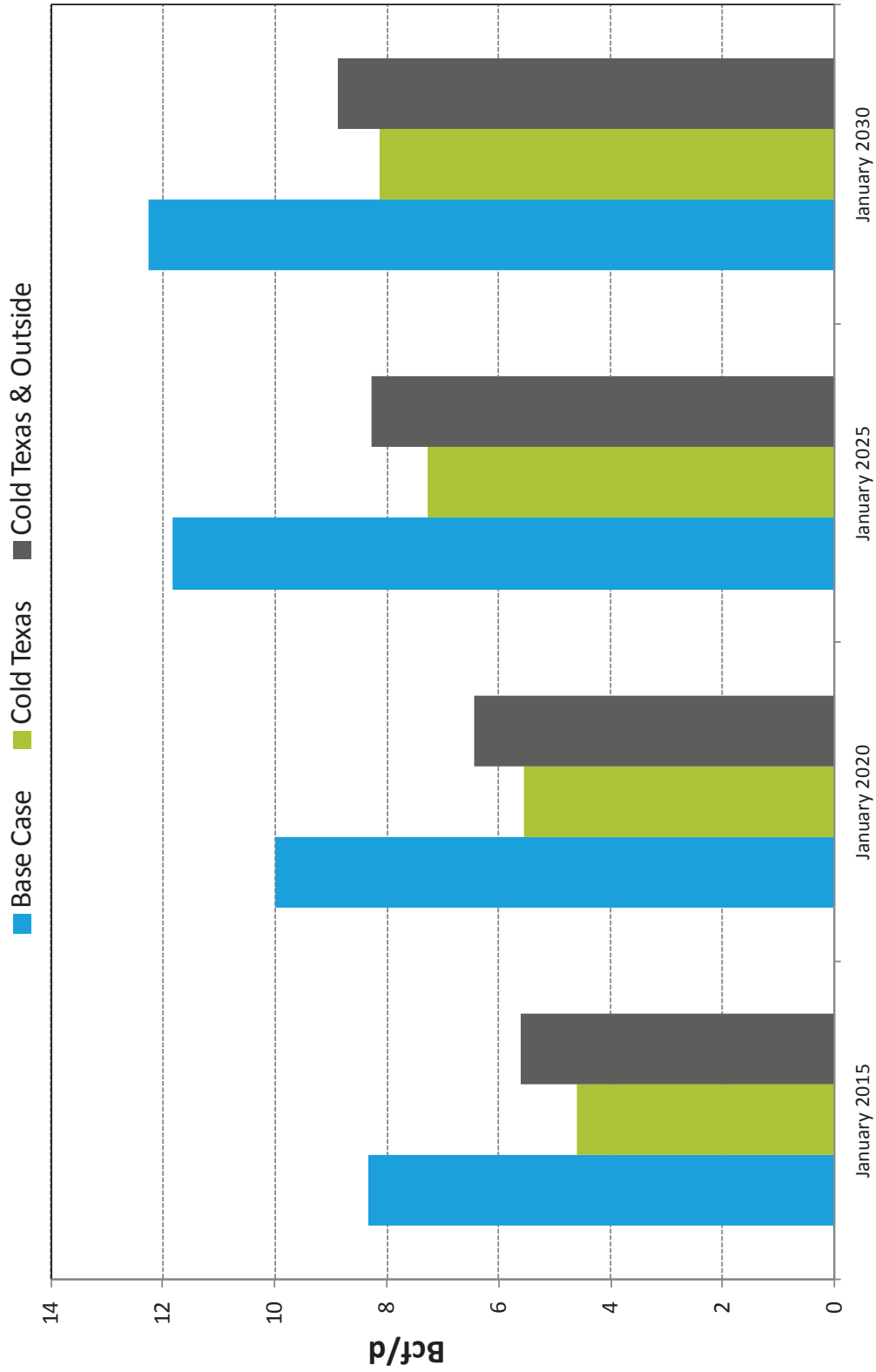
COLD TEXAS SCENARIO – REDUCES AVAILABLE TEXAS EXPORTS BY 6 BCF/D BY 2030

Projected Texas Supply and Demand Balance - Cold Texas



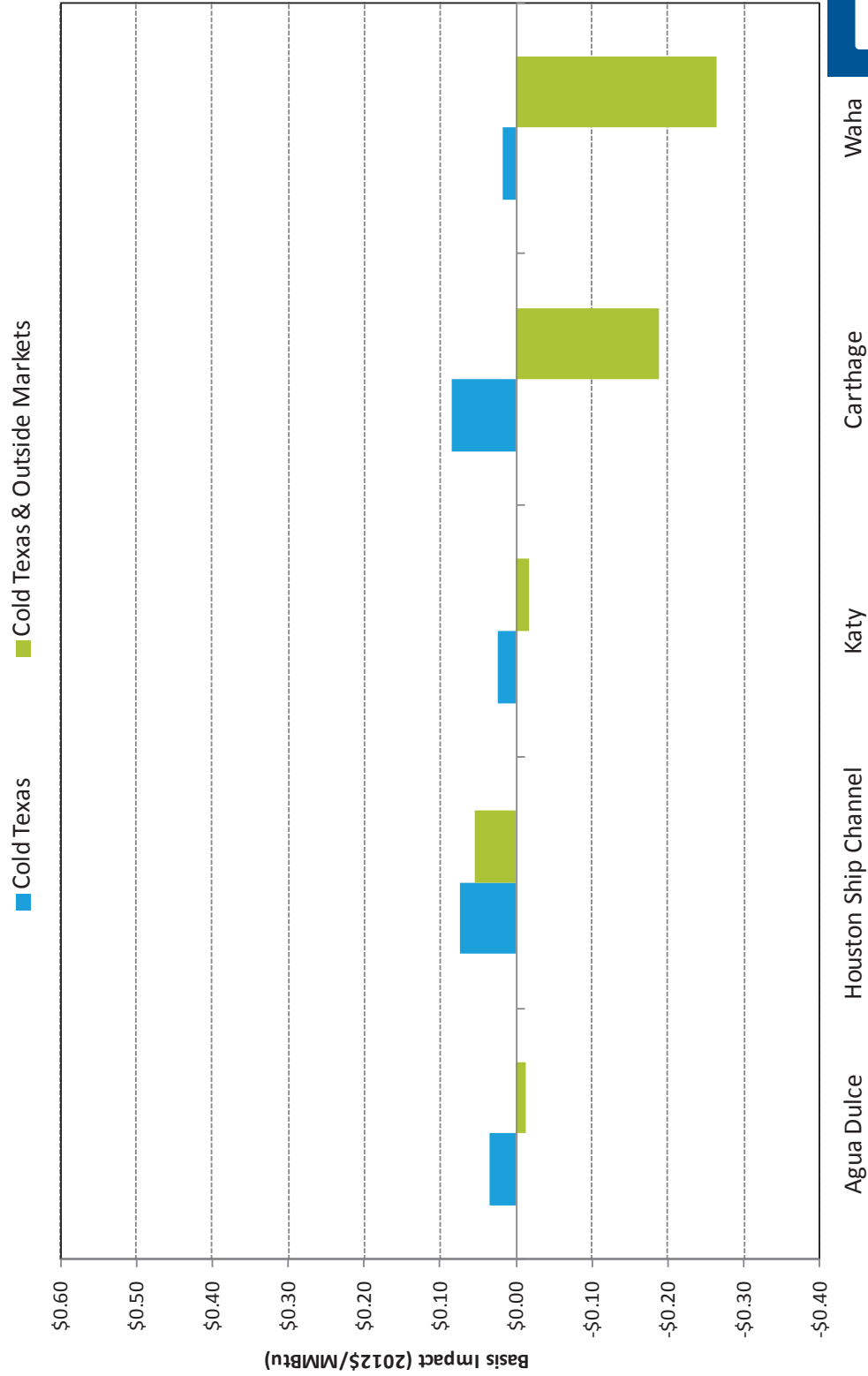
NET PIPELINE EXPORTS FROM TEXAS ARE REDUCED UNDER THE TWO EXTREME WEATHER SCENARIOS

Projected NET Pipeline Exports from Texas



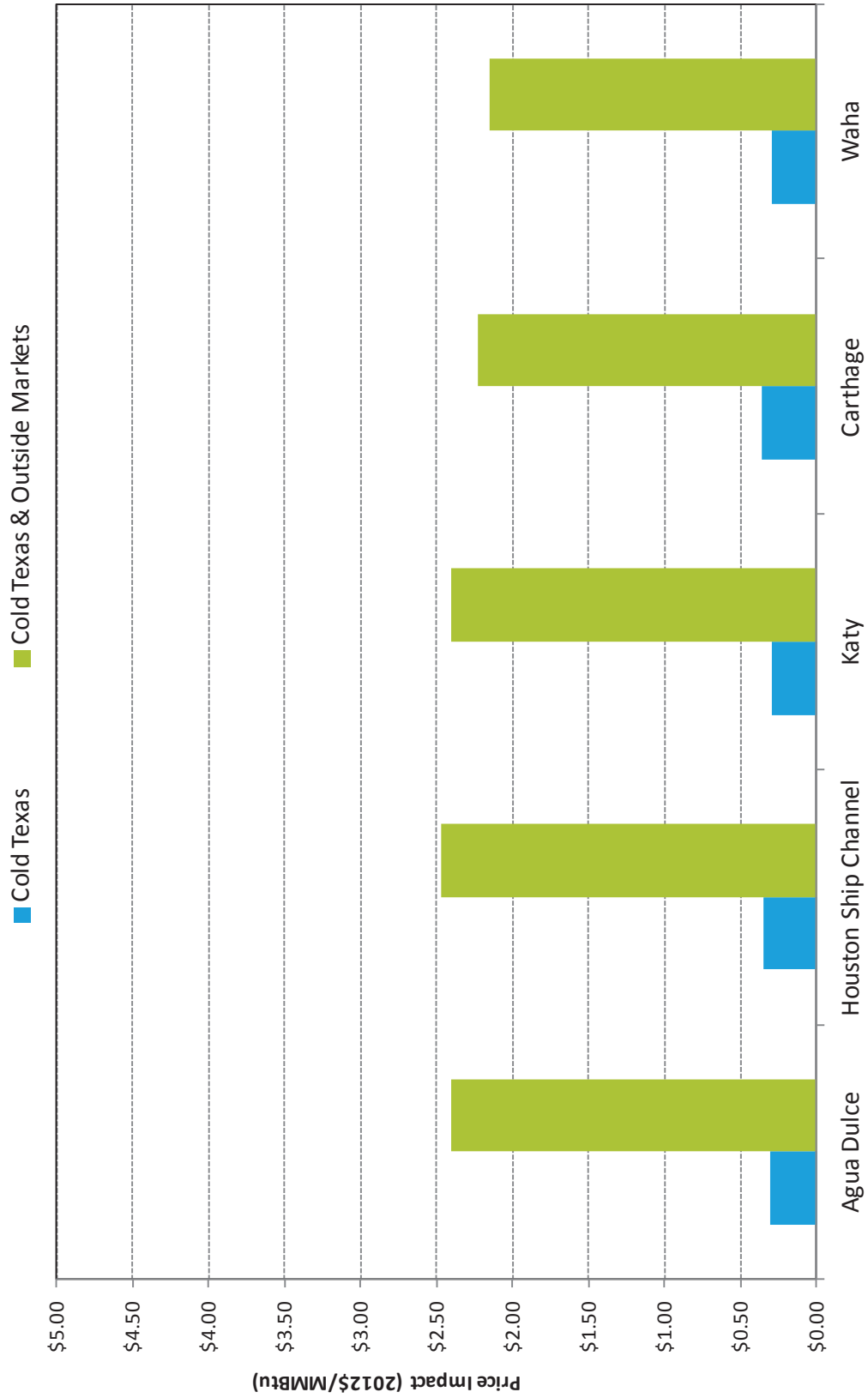
COLD TEXAS AND COLD TEXAS & OUTSIDE MARKETS HAVE LIMITED IMPACT ON REGIONAL BASIS

Average Basis Impacts Across Scenarios - Texas Markets



EXTREME WEATHER ACROSS TEXAS AND OTHER MARKETS RAISES NATIONAL AND REGIONAL PRICES

Average Price Impacts Across Scenarios - Texas Markets



Waha

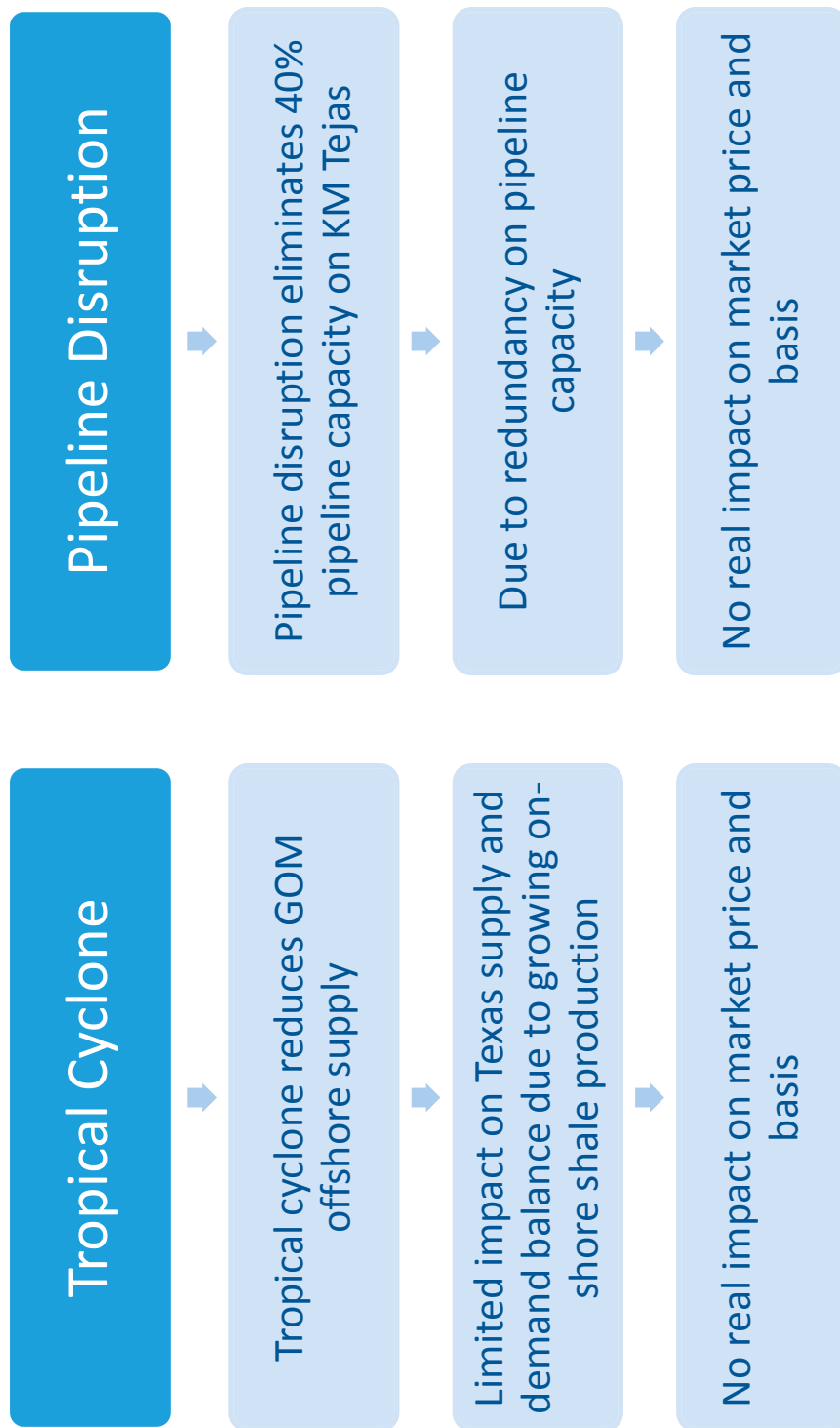
Carthage

Katy

Houston Ship Channel

Agua Dulce

TROPICAL CYCLONE & PIPELINE DISRUPTION HAVE LIMITED IMPACTS ON THE ERCOT MARKET



DISCUSSION OUTLINE

- A. Review of Current Natural Gas-Fired Generation and Infrastructure supporting Power Generation Needs
- B. Review of Projected Natural Gas Demand for Electric Generation (2020-2030)
- C. Assessment of sufficiency of Natural Gas Infrastructure to serve electric generation needs
- D. **Identification of Regional Constraints in adding Natural Gas Infrastructure**



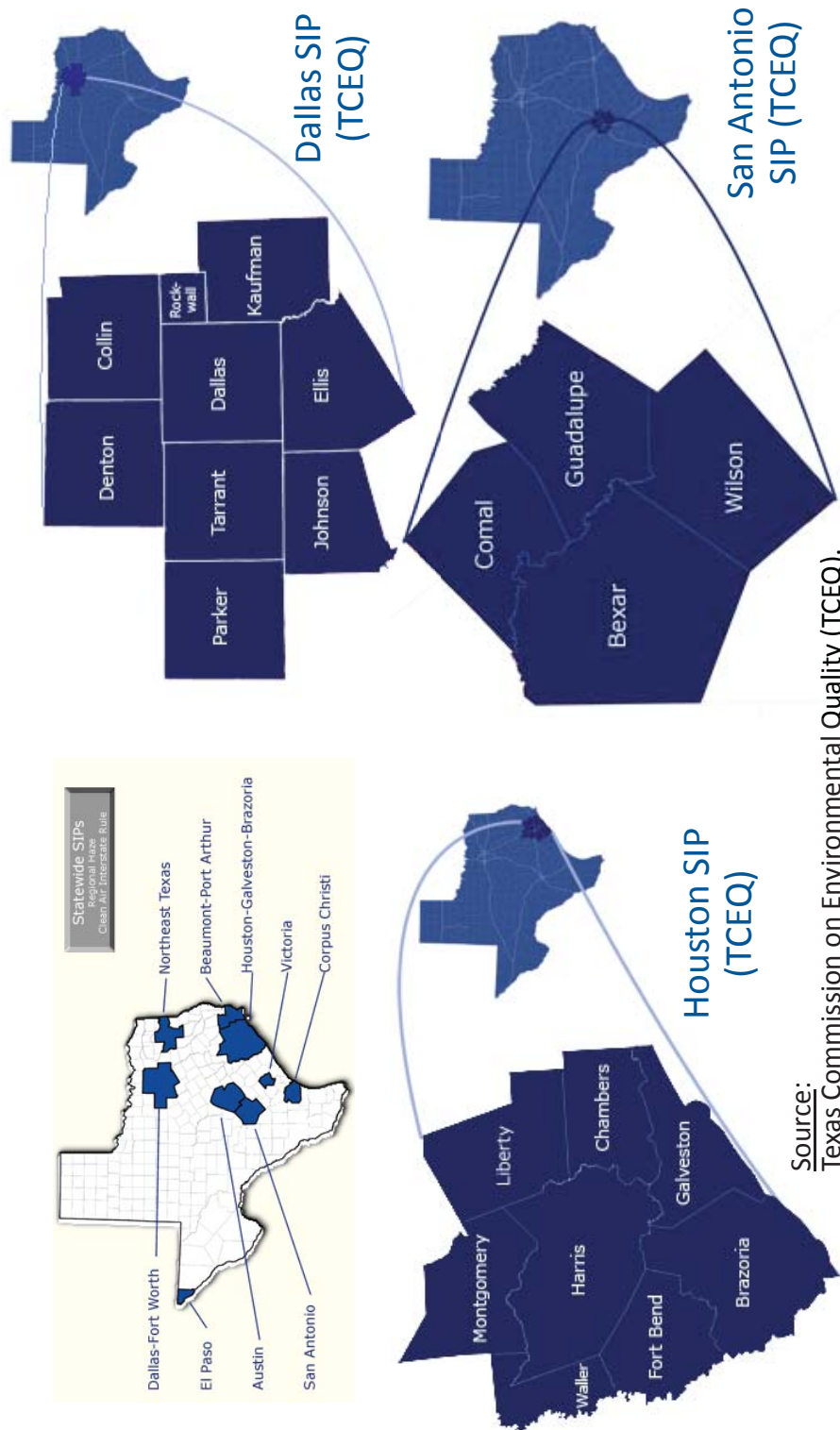
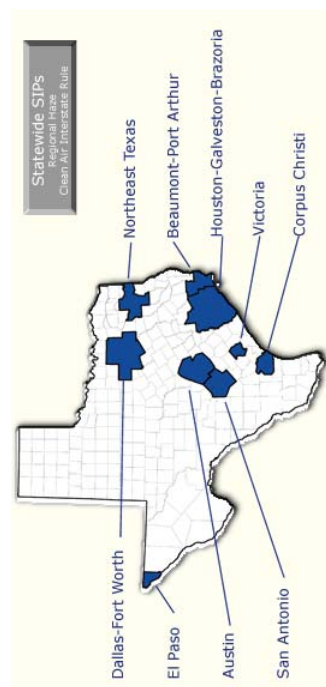
SUMMARY OBSERVATIONS – TASK D

- At least three government agencies make authoritative decisions that affect development permits for natural gas infrastructure
 - Railroad Commission of Texas (TXRRC)
 - Texas Commission on Environmental Quality (TCEQ)
 - US Environmental Protection Agency (EPA)
- At least two other government agencies can influence permit decisions affecting water or land use
 - Texas Water Development Board (TWDB)
 - Texas Parks and Wildlife Department (TPWD)
- Air quality related to natural gas development is an issue for the Dallas, Houston and San Antonio regions
 - Gas flaring is an emerging issue in the Eagle Ford region
- Water availability has been recognized as an issue in the Dallas and San Antonio regions (Odessa not yet studied) and drought remains a concern
 - TXRRC has concluded there is no problem (reliance on groundwater) although the issue remains debated for Eagle Ford region
 - TWDB and TCEQ remain more cautious (issues of drought and aquifer recharge)
- Endangered species (both plants and animals) are recognized by EPA/TPWD in all highlighted development areas

Development issues have evolved rapidly since 2008 and consensus has not been reached regarding go-forward plans

ENVIRONMENTAL CONCERNS: AIR QUALITY

- Dallas, Houston and San Antonio all are under TCEQ State Implementation Plan (SIP) supervision to improve air quality per EPA
- For now, Odessa and Brownsville are not under SIPs



Source:

Texas Commission on Environmental Quality (TCEQ).

Air quality issues involve traffic and facilities needed to build and operate natural gas infrastructure



INFRASTRUCTURE ISSUES IN THE EAGLE FORD SHALE AREA*: ROADS, PIPELINES, WATER AND FLARING (1 OF 3)

- Roads are inadequate and cannot be properly maintained under the load growth of development traffic
 - Loaded trucks needed per gas well:
 - 1,184 to bring well into production
 - 353 per year to maintain production
 - 997 for refracturing (every 5 years)
 - Road costs are \$80K/mi/year O&M upward to \$1.9MM/mi if new build
- **Pipeline construction would help reduce at least some truck traffic but some legal issues have slowed pipeline development**
 - 20-inch crude oil pipeline running 50 miles would displace 1,250 tank truck trips per day
 - The presumed access to eminent domain for obtaining right of way was made uncertain by *Texas Rice Land Partners, Ltd. v. Denbury Green Pipeline-Texas, L.L.C.*, 363 S.W.3d 192 (Tex. 2012)
 - TXRRC has no authority to intervene on behalf of pipeline developers and some projects have slowed their plans

*Source: Railroad Commission of Texas(TXRRC).
http://www.rrc.state.tx.us/commissioners/porter/reports/Eagle_Ford_Task_Force_Report-0313.pdf

Heavy wear on overloaded roads has become a somewhat unexpected bottleneck for other development objectives



INFRASTRUCTURE ISSUES IN THE EAGLE FORD SHALE AREA*: ROADS, PIPELINES, WATER AND FLARING (2 OF 3)

- Pipeline routing also is expected to address local concerns (even with eminent domain) – requiring more time to negotiate
 - Use road corridors wherever possible to minimize off-road impacts
 - Maximize distance from homes and minimize damage to natural landscape, including vegetation
- **Water availability is not totally resolved but oil & gas-related water demands are argued to be less impactful than other uses**
 - “Mining water use” (as classified by the TWDB) is 1.6% of state’s water use compared with 26.9% municipal and 55.9% irrigation
 - Actual “mining water” percentages are higher in the affected counties - and skewed toward groundwater for which opinions differ regarding the resource adequacy
 - Considers viable solutions to include a “water market” (i.e., sell water rights to the highest bidder) and a dilution of impacts by spreading groundwater demands across multiple GCDs
 - Assumes readily available injection wells for wastewater handling
 - Assumes future droughts can be handled by reassigning water rights

*Source: Railroad Commission of Texas (TXRRRC).

http://www.rrc.state.tx.us/commissioners/porter/reports/Eagle_Ford_Task_Force_Report-0313.pdf

A consensus has not been reached on water issues and possible upsets from future severe droughts are recognized



INFRASTRUCTURE ISSUES IN THE EAGLE FORD SHALE AREA*: ROADS, PIPELINES, WATER AND FLARING (3 OF 3)

- Gas flaring is used increasingly as gas takeaway infrastructure is lagging well construction
 - TXRRC issues flaring permits but TCEQ issues air-emissions permits so the two agencies require close coordination to balance different criteria
 - TCEQ prefers flaring to venting
 - Some industry advocates prefer venting as more cost-effective
- TXRRC has some internal disagreements about flaring vs. venting policies going forward
 - Tightening requirements (less venting and more restrictive flaring) could slow development
- There is no funding plan in place to address the roads, pipelines and water issues - although they are beyond the capabilities of the affected counties
 - Either State of Texas will need to address or additional burden will be transferred to developers

*Source: Railroad Commission of Texas(TXRRC).

http://www.rrc.state.tx.us/commissioners/porter/reports/Eagle_Ford_Task_Force_Report-0313.pdf

A consensus has not been reached on gas flaring and how related air emissions might impact future oil & gas permits





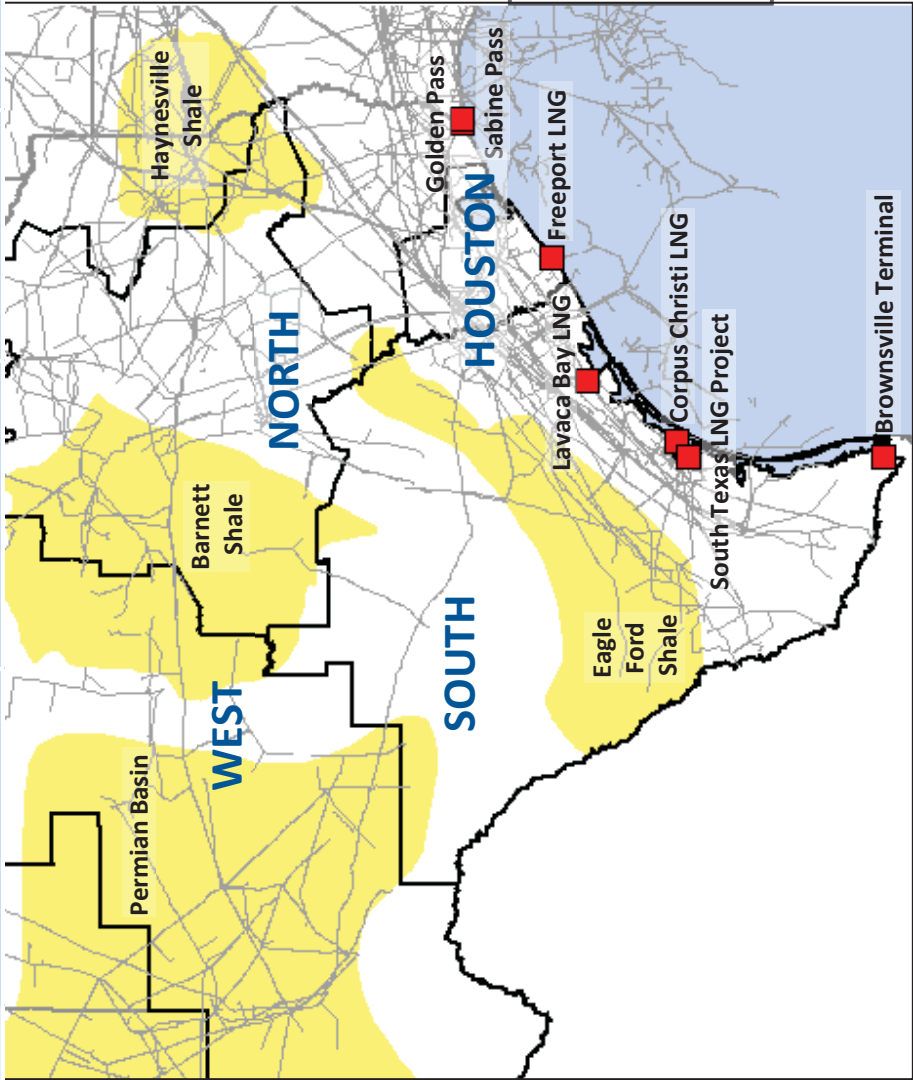
APPENDIX

SUMMARY FINDINGS – HIGH LNG EXPORTS AND HIGH MEXICAN PIPELINE EXPORTS

- In the High LNG Export Scenario, additional LNG exports from Freeport will have a moderate impact on regional Texas market prices/basis.
 - Sufficient pipeline infrastructure exists to meet additional LNG Export demand and peak summer power generation gas demand in the Houston region
 - Higher pipeline utilization expected from North/West Texas and South Texas to Houston to meet additional demand needs
- In the High Mexican Pipeline Export Scenario – additional 2.0 Bcf/d of incremental pipeline capacity from South Texas to Northeast Mexico will have a moderate impact on regional Texas market prices/basis
 - Northeast Mexican power generation growth coupled with reduced LNG imports will increase the utilization of existing and incremental pipelines serving the market
 - Diminished South to Houston flows will be replaced by North and West Texas imports

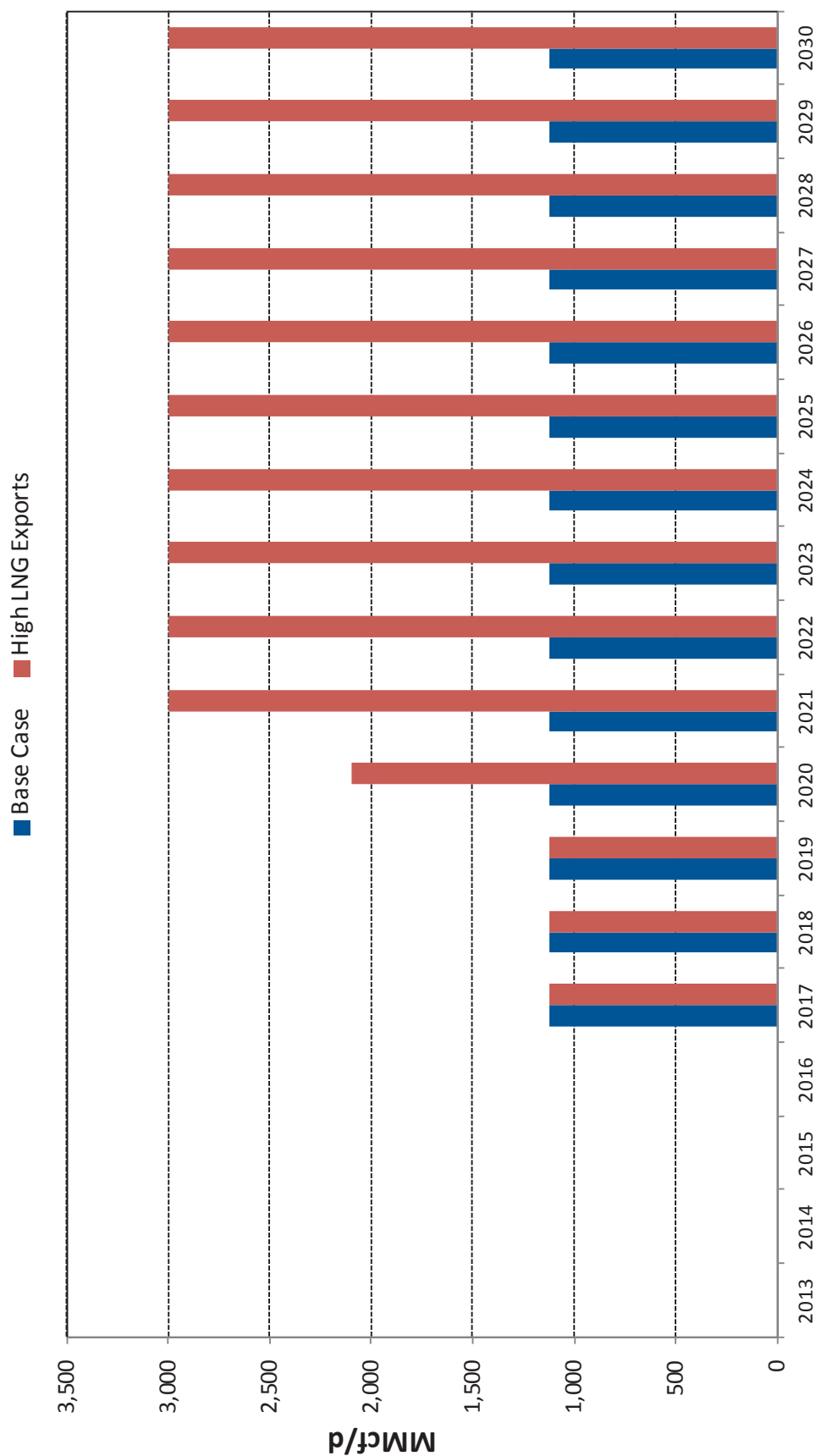
LNG EXPORT TERMINAL DEVELOPMENT COULD POTENTIALLY ADD 10 BCF/D OF INCREMENTAL DEMAND

Region	Terminal Name	Sponsors	Status	Capacity (bcf/d)	Proposed Online Date
TX	Freeport LNG	Freeport LNG	Non-FTA Approved	2.8	2017
	Brownsville Terminal	Gulf Coast LNG Export	Non-FTA Pending	2.8	2018
	Lavaca Bay LNG Project	Excelerate Energy	Non-FTA Pending	1.38	4Q 2017
	Corpus Christi LNG	Cheniere Marketing	Non-FTA Pending	2.1	2017
	South Texas LNG Project	Pangea LNG B.V.	Non-FTA Pending	1.09	Apr 2018

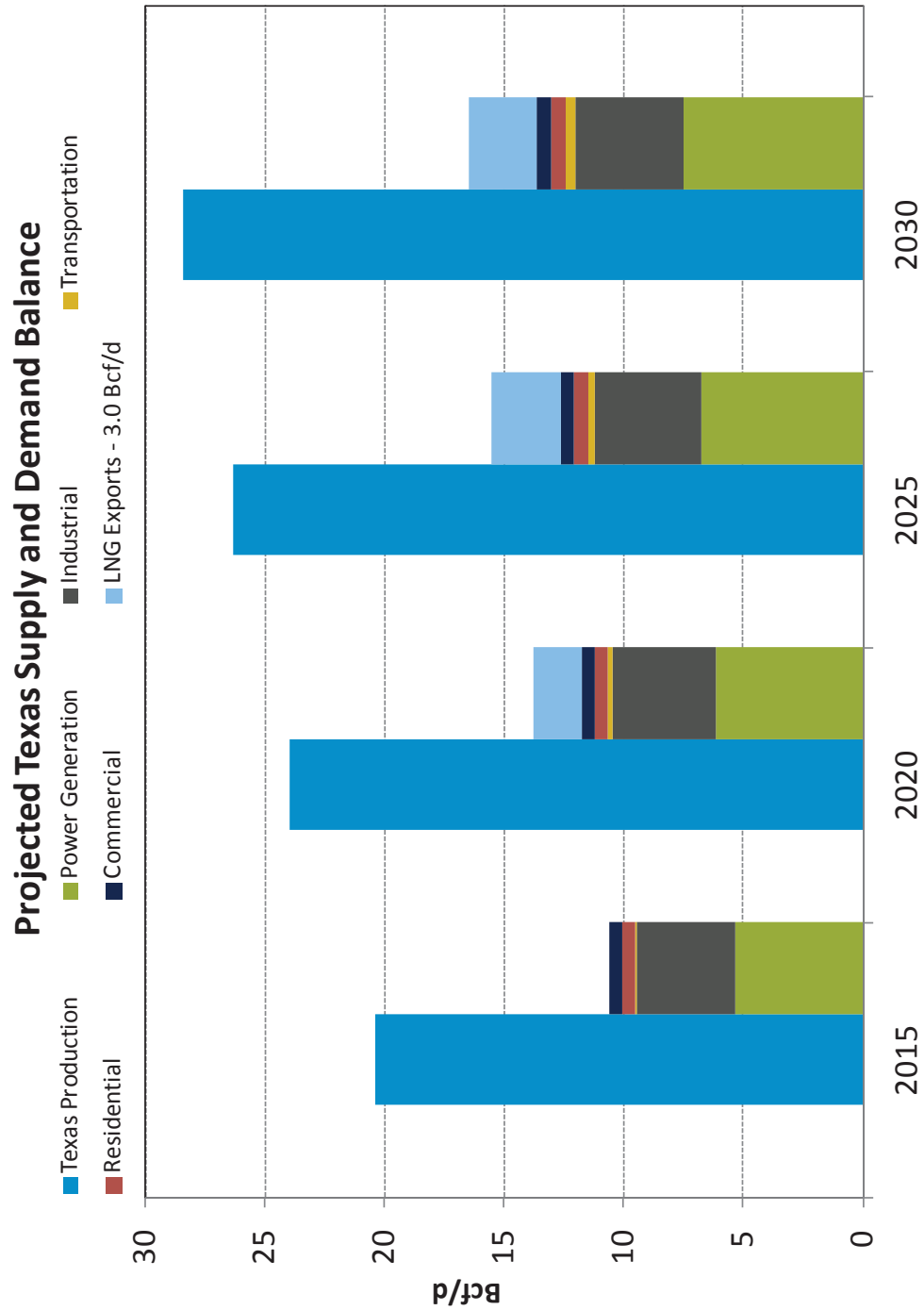


HIGHER LNG EXPORT SCENARIO – AN ADDITIONAL 2 BCF/D OF LNG EXPORTS FROM FREEPORT BY 2021

LNG Export Assumptions - High LNG Export Scenario

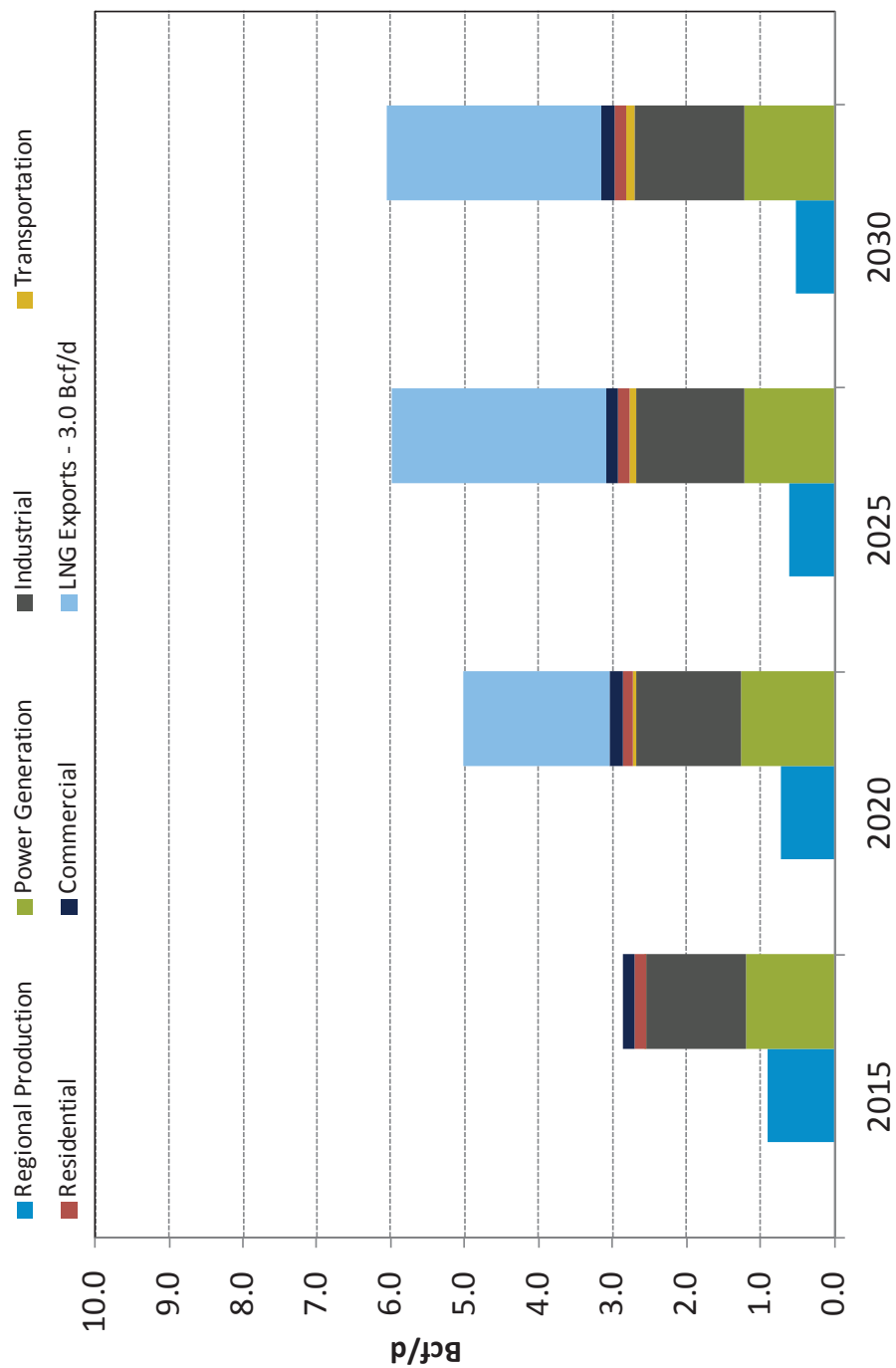


HIGHER LNG EXPORTS REDUCE TEXAS PIPELINE EXPORTS BY 2 BCF/D



ADDITIONAL FREEPORT LNG EXPORTS INCREASE PIPELINE IMPORTS TO ERCOT HOUSTON

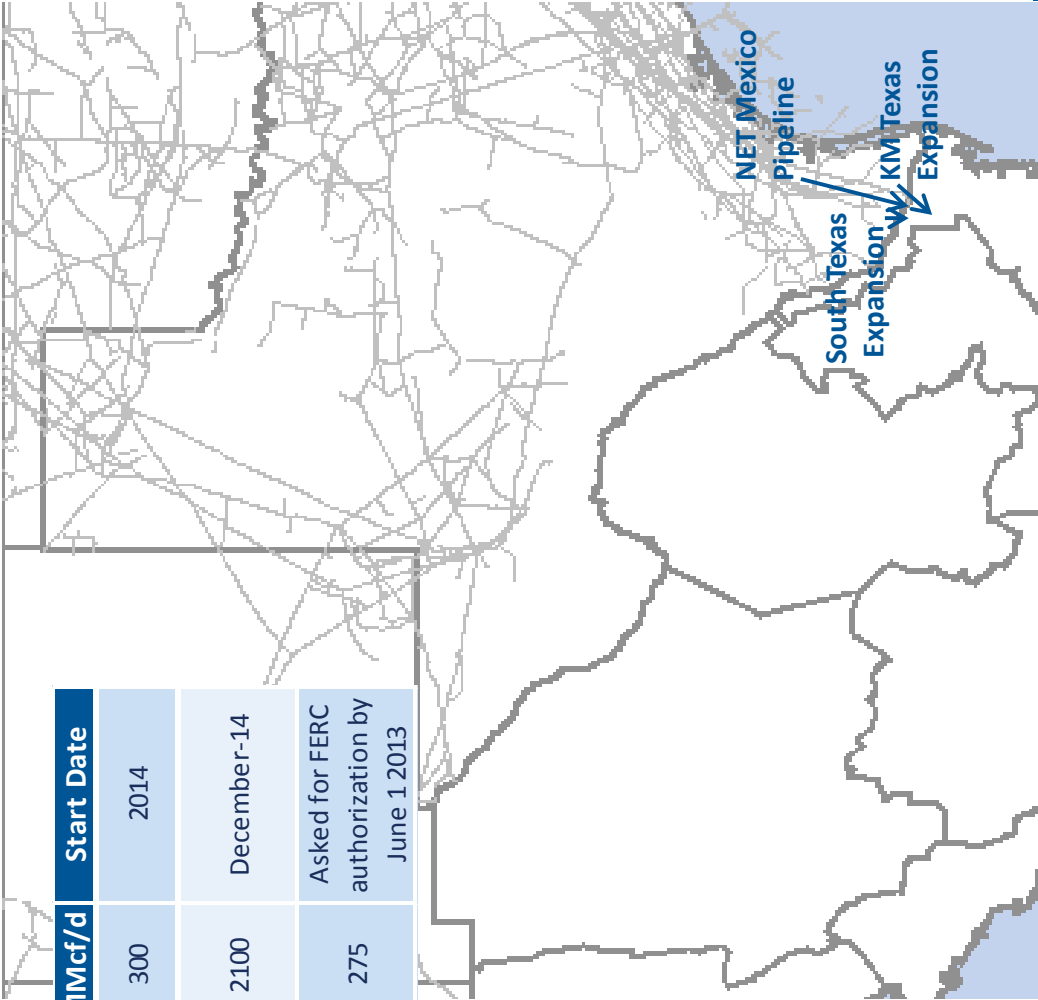
Projected ERCOT Houston - Supply and Demand Balance



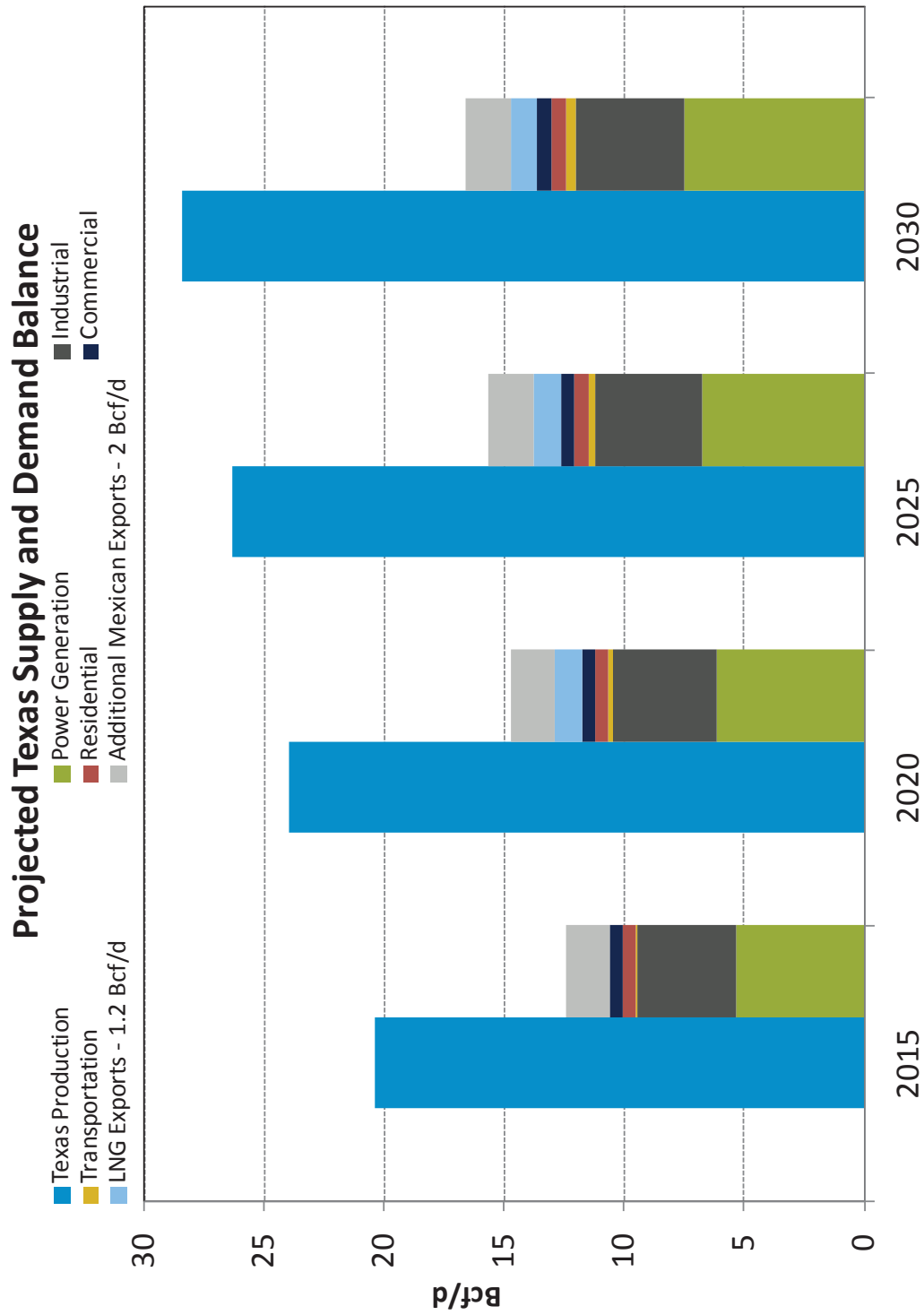
PROPOSED EXPORT PIPELINES TO MEXICO FROM SOUTH TEXAS EXCEED 2.7 BCF/D

Project Name	Sponsor	MMcf/d	Start Date
South Texas Expansion Project	Texas Eastern Transmission	300	2014
Eagle Ford Shale Pipeline System Expansion	NET Mexico Pipeline	2100	December-14
Kinder Morgan Texas Pipeline Expansion	Kinder Morgan	275	Asked for FERC authorization by June 1 2013

- Current Existing South Texas Export Capacity to Mexico: 2.3 Bcf/d
- Average Utilization 2012-2013: 46% or 1.1 Bcf/d
- Analysis considered the impact of incremental export demand of 2 Bcf/d from Mexico

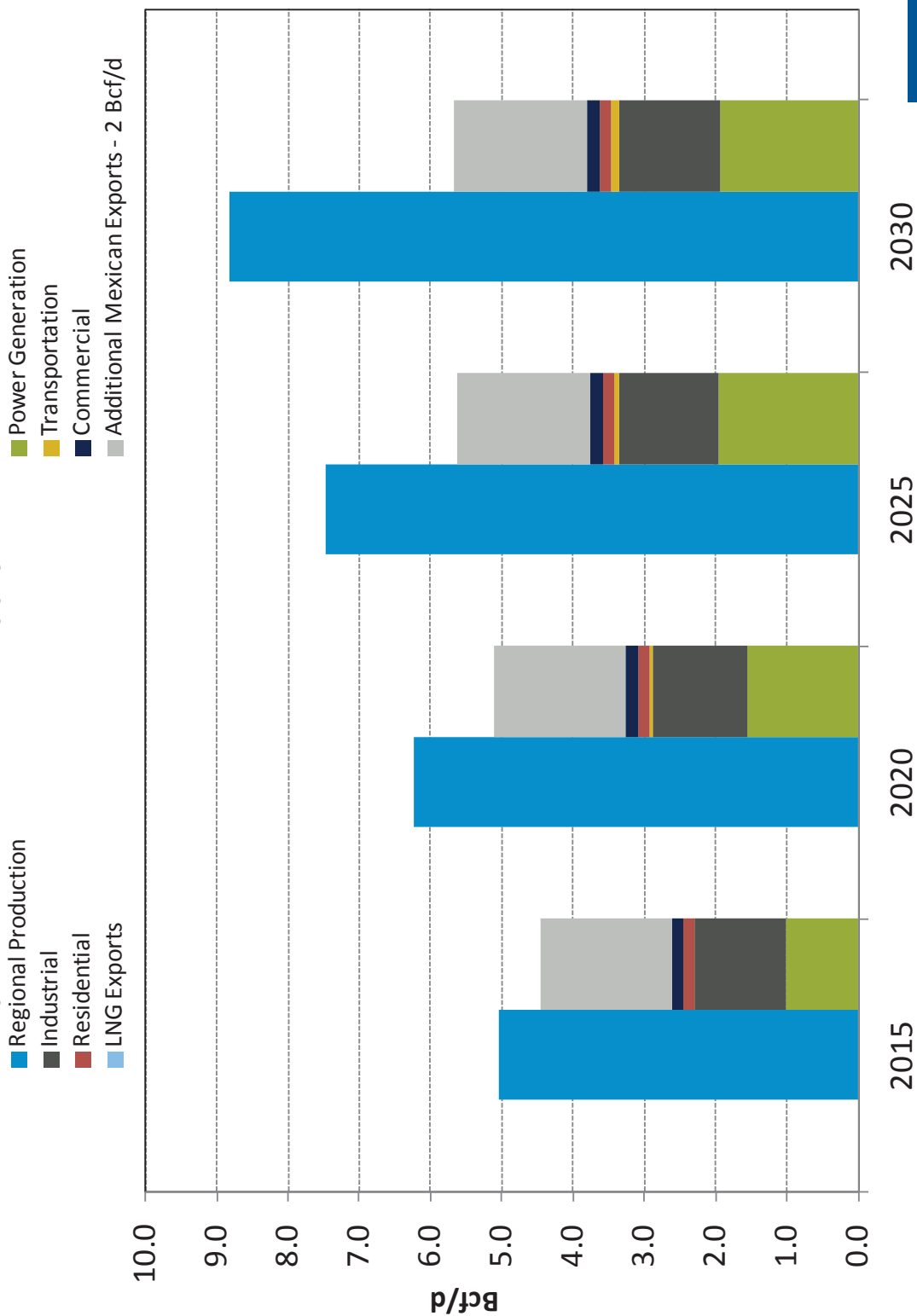


HIGH EXPORTS TO MEXICO REDUCE GAS AVAILABLE FOR INTERSTATE EXPORTS BY 2 BCF/D



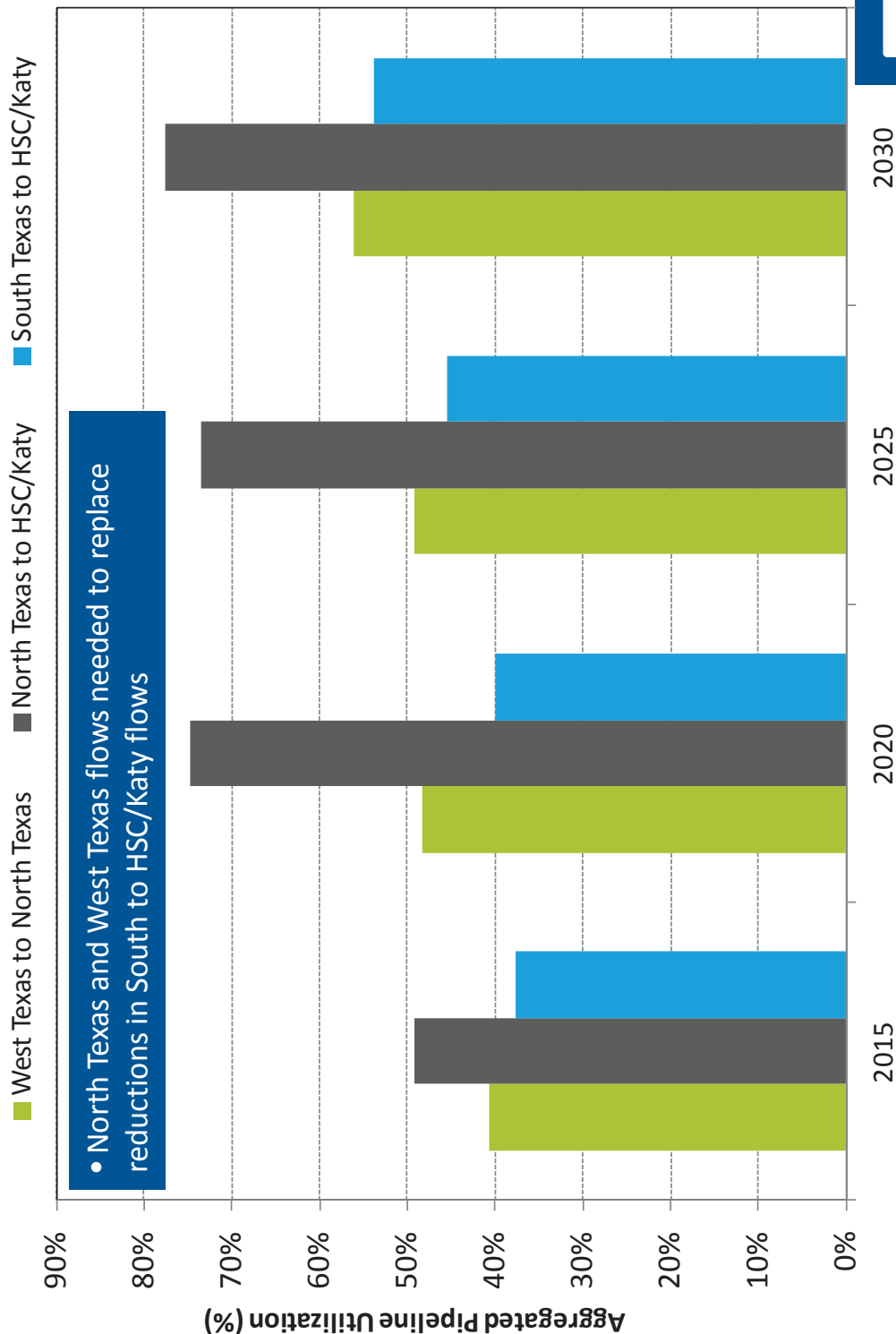
HIGH MEXICAN PIPELINE EXPORTS NARROW AVAILABLE EXPORTS FROM ERCOT SOUTH TO HOUSTON

Projected ERCOT South - Supply and Demand Balance



HIGH MEXICAN PIPELINE EXPORTS REDUCE FLOWS TO ERCOT HOUSTON FROM SOUTH TEXAS

Projected Annual Average Pipeline Utilization



**Appendix V Water Use and Availability in the ERCOT
Region**

**Water Use and Availability in the ERCOT Region
Drought Analysis
Black & Veatch Report to ERCOT**

WATER USE AND AVAILABILITY IN THE ERCOT REGION

Drought Analysis

BLACK & VEATCH PROJECT NO. 162854

PREPARED FOR

ERCOT

12 DECEMBER 2013

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1 Executive Summary

In 2011 Texas had its worst single-year drought on record. This was widely publicized in the news media and was a concern for many water users, including power generators. The average rainfall across the state in 2011 was 14.89 inches, the lowest on record and below the previous record of 14.99 inches which was 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. Normally the state average rainfall is approximately 28 inches by comparison.



Since late 2011 the Electric Reliability Council of Texas (ERCOT) has been providing monthly updates of reservoir levels at power plant locations with certain risk factors including reservoir level compared with previous lows and megawatts at risk. An initial survey of generating units and request of information to generators regarding an assessment of drought risk has also been conducted. A number of other studies were initiated with reference to the long-term drought effects on power generation including projects managed by Sandia National Laboratories and Argonne National Laboratory. These studies which were developed for ERCOT and the Western Electricity Coordinating Council (WECC), were based on the hydrology of Texas (and the other western states for the WECC portions), streamflow, modeling and reservoir storage. Groundwater, wastewater, and brackish groundwater costs were also included in these analyses.

Initial review of survey data provided by the generators and the actual unit history from 2011 have shown that most generators were prepared for, or had contingency plans for, a single-year severe drought such as experienced in 2011. The more complex issue for generators in Texas appears to be a multi-year drought when water storage is further diminished. A multi-year drought occurred in Texas between 1950 and 1957. While this drought was not as severe on an individual year basis as 2011, this is still the period of record for extended drought across most of the state.

ERCOT contracted with Black & Veatch to review the analysis completed by Sandia and Argonne National Laboratories and to assist in linking these studies to ERCOT needs and development of a gap analysis to enable more detailed risk analysis of a multi-year drought scenario.

1.1 POWER GENERATION WATER USE

One of the driving factors for analysis of water supply and availability for power generation during drought is the misunderstanding of water withdrawn versus water consumed. Many reports have stated that power generation is the largest single user of water in Texas with over 49% of the demand for the whole state. What is not often stated is that this is the amount withdrawn. The actual amount consumed is approximately 3%.



While this is still a significant amount it is by no means the greatest consumption. As an example this amount consumed is very similar to the amount of water loss as reported by municipal water utilities in Texas (i.e., the amount of water that is treated by municipal utilities, but does not reach the customer due to leakage, main breaks, and non-revenue uses).

There do appear to be sufficient water resources within the state to allow building of additional thermal units if deemed appropriate. However, the specific technology and cooling system does need to be managed carefully, but all types of units should be considered when determining resource adequacy and siting of new generation units.

1.2 IMPROVING RELIABILITY, EFFICIENT WATER USE

Water shortages and lack of water availability for power plants can lead to plant outages, or reduced utilization that can cause reliability problems especially during periods of peak demand. Most generators in the ERCOT region do appear to have contingency plans in place to mitigate short-term, severe drought such as what occurred in 2011.

Efficient use of water is also important to maximize the resource and to extend the potential for generation through those droughts. There are many types of power generation technologies which allow for different fuels to match varying demand, supply and pricing. There are also different technologies for cooling which can increase or reduce the amount of water used. While it appears on the outside that air cooling is the best option for conserving water, there are many other considerations that influence the desirability of this technology. In almost all locations air cooling is more expensive than water cooling, except where the cost of water is exceptionally high. Air cooling also generally uses more power itself, thereby reducing the efficiency of the unit compared to wet cooling. However, it is also obvious that in water-short areas air cooling may be the most effective and environmentally sensible technology for thermal units.

Due to the increasing view that drought is a new-normal in Texas and to reduce risk further it is expected that large water withdrawing and consuming applications such as once-through cooling facilities are only considered for future development in locations (or from storage sources) with averages of more than 35-inches of rain per year or from existing storage locations with water availability. Drought effects on electric reliability should be assessed in the context of weather zone and rainfall patterns in addition to the normal cost factors when determining new generation sites and technologies.

The current resource mix is varied and it is expected that the water resource mix to meet these generation demands will also stay varied for the foreseeable future.

2 Background Information

2.1 ERCOT, DROUGHT PREPAREDNESS, AND THE LONG TERM SYSTEM ASSESSMENT

Texas Senate Bill 20 (79th Legislature, 1st Called Session, 2005) requires that ERCOT study the need for increased transmission and generation capacity every two years and report the findings to the legislature. This provides a view of the needs 10-years into the future. Due to the severe drought in 2011 it was decided that a drought analysis be developed for the generating locations currently operational. Any problem areas could then be defined and alterations in the long term system assessment made. In addition, ERCOT wanted to improve system reliability by understanding the nature of drought with respect to the generation facilities both in the short- and long- term. This report outlines the study data evaluated and the recommendations developed.

This was conducted in conjunction with a long-term drought analysis prepared by Sandia Labs that includes both the ERCOT and WECC territories. The analysis' data was peer reviewed to increase its usefulness to ERCOT and to provide the foundation for some of the discussions of water availability.

In 2011, Texas had its worst single-year drought on record. This was widely publicized in the news media and was a concern for many water users, including power generators. The average rainfall across the state in 2011 was 14.89 inches, the lowest on record and below the previous record of 14.99 inches which was 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.

2.2 POWER GENERATION IN TEXAS

Texas has a diverse mix of different generating technologies including wind. Texas led the Nation in wind-powered generation nameplate capacity in 2010, and was the first State to reach 10,000 megawatts. However, this is still a minority of the power generated in the state. The current nameplate capacity for each of the main generation types is outlined in Table 1 below.

Table 1. Power generation nameplate Capacity in Texas in 2013 (Source: ERCOT Capacity Demand and Reserves Report update – May 2013¹)

GENERATION TYPE (2013)	NAMEPLATE CAPACITY (MW)
Natural Gas	49,337
Coal	19,115
Nuclear	5,150
Hydro Power	521
Wind	10,035
Combustion Turbines	5,516

¹ <http://www.ercot.com/content/news/presentations/2013/CapacityDemandandReserveReport-May2013.pdf>
(Summer fuel types 2014)

Wind, solar and combustion turbines are assumed to use no water. There is water involved in the process to develop the raw materials and construct the projects, but this is assumed to be negligible over the lifespan of the projects and is not discussed further here.

There are also a number of different providers of the electricity including privately- and publically-held independent power producers, cooperatives and municipal providers. The current status (2012) of this breakdown of power generation is outlined in Figure 1. Recently the largest amount of investment (since 2000) has come from privately-held and publically-held independent power producers.

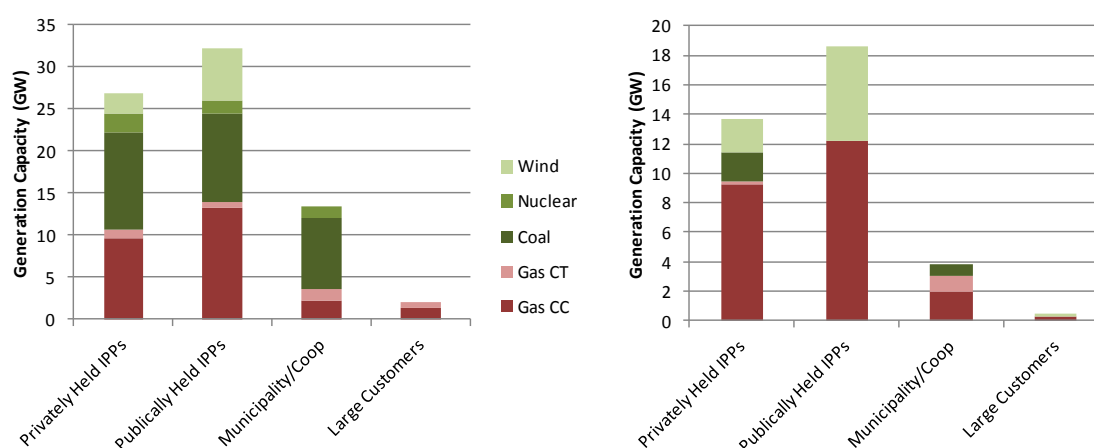


Figure 1. Existing and Future Generation by Investor Class (Source: Brattle Group Report, 2012, graphic reconfigured)

2.2.1 Cost of Water

Water is a comparatively low-cost item for power generators in normal running of existing systems. However, the development of large water resources and the cost to the generator when water becomes short in supply can raise prices and management complexities significantly.

The most costly water supplies in Texas only add \$3 or so per MWh during normal operation. This is true for water supplies purchased from municipalities where costs can rise to \$10 per 1000 gallons, or for projects with significant capital investment needed. This is a cost factor to consider, but is usually dwarfed by the operations and maintenance and fuel costs. The main focus is therefore directed to when the resource becomes unavailable or restricted and generation units have to shut down or significantly de-rate.

2.2.2 Water Use

A common misunderstanding in studies of power generation water supply by entities external to the industry is the difference between water withdrawn versus water consumed in the cooling cycle. Many reports have stated that power generation is the largest single user of water in Texas with over 49% of the demand for the whole state. What is not often stated is that this is the amount withdrawn and a very large amount of this is recirculated into the same water body it was withdrawn from. The actual amount consumed is approximately 3% of the state total. While this is

still a significant amount it is by no means the greatest consumption in Texas. Figure 2 below shows the water consumption by major water group within the state.

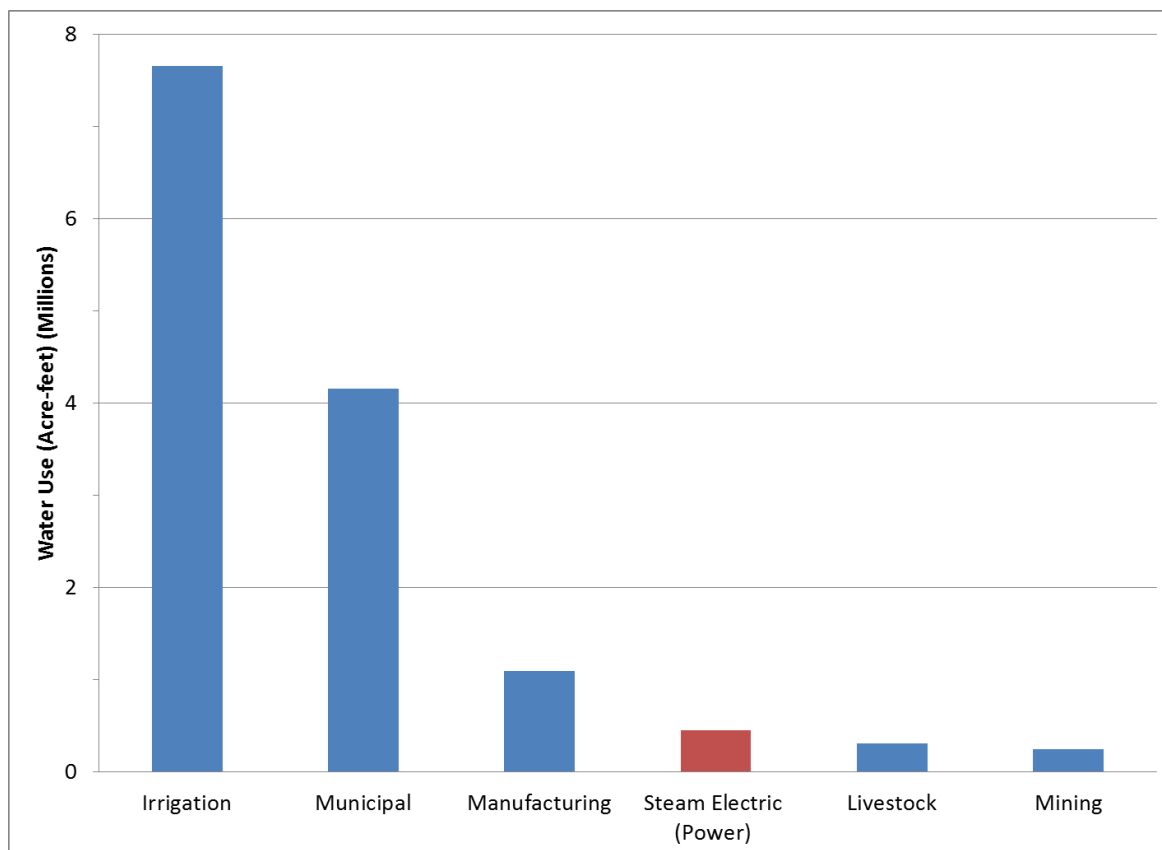


Figure 2. Water Use in Texas (2010) by Use Type (Adapted from TWDB 2010 Water Use Survey Estimates)

Water shortages and lack of availability can lead to plant outages, or reduced utilization that can cause reliability problems especially during periods of peak demand. In terms of electric reliability, water supply is an important factor for over 70% of the nameplate capacity. Therefore, the focus of this analysis is on water availability and its effect on power generation. In order to analyze this, the cooling methods, different water supplies, storage locations and drought potential will be discussed.

2.3 BASIC GENERATION UNIT OPERATIONS

Each generation technology has differing potential to be affected by drought. This includes the generation and cooling technology. Obviously water use and availability is the major component related to drought conditions, but increased temperatures and increasing cost of water supplies are also often coincident with drought (especially in the summer) and these can affect efficiency and generation capacity as well.

As a part of the process of converting fuel to electricity, many generation plants withdraw water from surface water sources, use this water for cooling various plant systems, and then return the water to the river or lake. During this process, the cooling water temperature rises. To protect the

receiving water, the National Pollutant Discharge Elimination System (NPDES) permit for each plant includes limits on the maximum discharge temperature and, in some cases, the in-stream temperature regime. To comply with these NPDES permits, all generators with these permits have to monitor water temperatures at each plant and manage water releases to assist in meeting permit requirements. If the quantity of water available for release is limited or its temperature is elevated (a condition that typically occurs in late summer months when rainfall and runoff is low and ambient temperatures are high), options to either alter river flows or derate the plants are evaluated. The most favorable option is implemented and can vary from day to day.

If the generating plant's output must be derated to meet thermal limitations due to constraints on available water releases, the energy must be provided by an alternate, and typically more expensive, generation source. Under extreme conditions, it is possible that the system load requirements would not be met and brownouts or blackouts could result. Nationally it is not uncommon for generators to derate their coal-fired plants for some period of time each summer to meet NPDES permit requirements. Nuclear plants are derated only occasionally.

2.4 GENERATION AND TRANSMISSION CAPACITY AFFECTED BY DROUGHT

Generation capacity will be affected if drought conditions do become severe enough to alter the water supply characteristics of an area. Most of Texas surface water is permitted. Permit holders that got their authorization first (senior water rights) are entitled to receive their water before those water right holders that got their authorization later (junior water rights). If a water right holder is not getting water they are entitled to, they can call upon the Texas Commission on Environmental Quality (TCEQ) to take action to enforce the priority doctrine – a senior call. When a senior water rights call happens this is one of the first signs that risk has increased significantly. Currently the TCEQ views the municipal and power generation water rights separately to other water rights. TCEQ takes into consideration concerns related to public health, safety and welfare. This has previously meant that power generation water supplies have not been curtailed. However, in 2013 some power generation water rights were curtailed after discussion with the relevant entities to make sure that they could meet their water requirements through other means for the duration of the senior call. It is possible that, there may come a time in the future when certain municipal and power generation rights cannot be met.

The aim of this study and modeling is to warn ERCOT and the power generators and get in front of these risks in order to plan on current and future generation which will be significantly affected by drought conditions of record (such as in the 1950s or a multi-year drought with multiple years similar to 2011).

2.5 POWER GENERATION WATER SUPPLIES

Texas has a varied portfolio of water resources including significant surface water, groundwater, brackish groundwater and seawater. There are also the secondary sources of reused, or recycled water.

2.5.1 Surface water - Reservoirs/Lakes

Many power generators in ERCOT access water for cooling and other uses from reservoirs and lakes. These are often built specifically for power generation. There are a few which have

hydroelectric components (for example, Lake Texoma and, Lake Whitney), but these have minimal generation capacity (less than 100 MW each) and so are not considered significant in this analysis.

2.5.2 Off-channel Reservoirs (including systems with river intakes)

Most of the river intakes are utilized as part of an off-channel reservoir of some sort. A number of the lake cooled systems also have a secondary water source such as a water right from a nearby river or estuary. Examples of this include; Dansby (Bryan Lake), Valley (Valley lake), Comanche Peak (Squaw Creek Lake), and the South Texas project (STP Lake). STP accesses water from the Brazos river. The Valley plant in North Texas gets its supply from the Red River.

2.5.3 Groundwater

Groundwater is not currently considered as a major resource for power generation in Texas. However, future analysis may well include groundwater due to the needs for drought-proofing of power plants and the possibility for desalination and the power requirements (and water use) that those systems will need. This has not been studied in the Sandia work, but will be analyzed briefly in this report.

There are a small number of groundwater-supplied systems in the ERCOT region as shown on the associated graphic Figure 3.

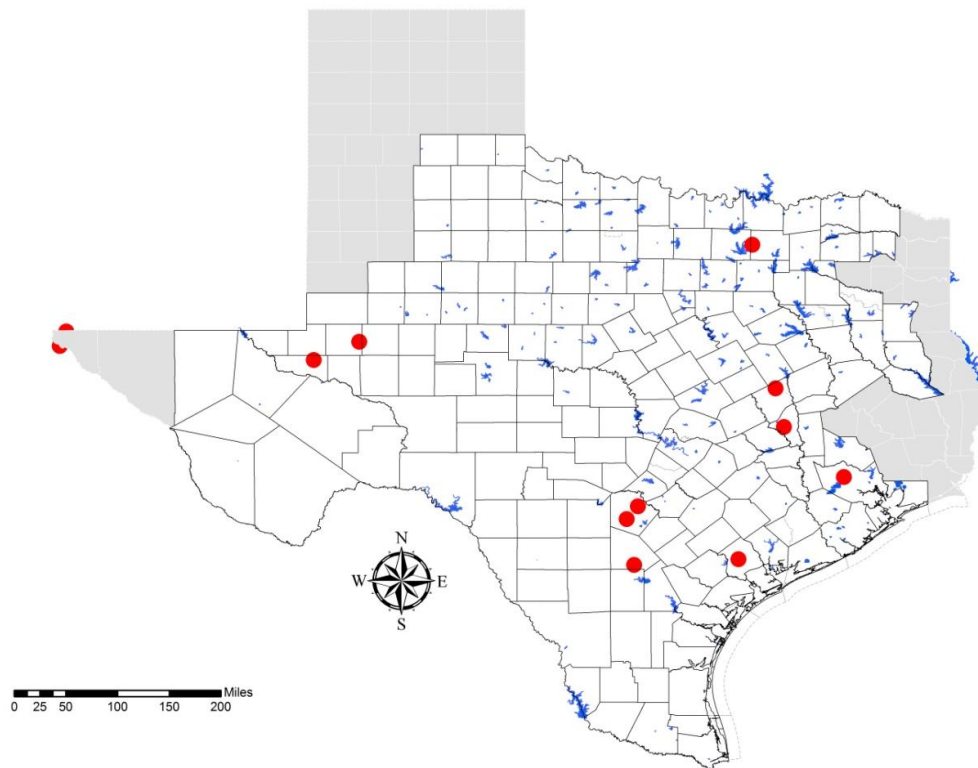


Figure 3. Groundwater Supplied Units

2.5.4 Brackish Groundwater or Seawater

Brackish groundwater (basically a mixture of fresh and salt water) is prevalent in many locations within Texas. Many of the potable aquifers within the state have deep sections which are brackish. These include the Hueco-Mesilla Bolson (used by El Paso Water Utilities as a potable resource and a brackish resource in different locations), the Carrizo-Wilcox and the Gulf Coast aquifers. If demand is sufficient and cost considerations can be overcome these can be significant resources for the state. Seawater is also an option along the Gulf coast and is already utilized or available in a small number of locations.

2.5.5 Municipal Supplies (Direct from Distribution System)

Municipal supplies have the same origins as the sources outlined above. However, this adds an extra layer of uncertainty for a power generator as they often do not have control over these water rights. In some cases it is possible that the supplier will be forced into a specific water allocation or conservation reduction and may pass this reduction down to the power generator. In these cases, a derating of the facility may be necessary if the water supply does not match the plant requirements.

2.5.6 Reuse

Reuse, or recycled water is generally purchased from a municipal entity as it leaves their treatment plant. There are currently at least five sites and approximately 4,000 MW of generation which is produced reportedly utilizing a reuse water supply. Since most municipal reuse water is derived from sewer flows, the volume available is driven by the sewer inputs. In the long-term if municipal water conservation significantly reduces use it will also reduce sewer flow. However, this is not expected to affect reuse water availability in the planning horizon. Reuse water is expected to become a more highly utilized resource for power generation in the future due to it being available in large volumes at a single source location (from large waste water treatment plants), and it will generally be a lower price than other municipal supplies. Obviously there are still water quality and river rights to be included in any availability and cost analysis.

2.6 RESERVOIR STORAGE

Reservoirs in a number of locations around Texas were analyzed to gain an understanding of the differing water demand conditions. Resources in North Central Texas have large consumption requirements and steep demand gradients on each of the power generation lakes due to the significant municipal supply needs and other growing demands (Table 2). This trend is likely to increase.

Table 2. North Texas Reservoirs with Power Generation – Demand Indicators

LAKE	MW IMPACT*	WATER LEVEL (ABOVE MSL)	RESERVOIR TOTAL DEPTH (FT)	WATER LEVEL LOSS PER MONTH (FT)**
Arlington	1265	550	45	2.24
Bridgeport	1865	836	84	2.13
Lavon	406	492	39	1.86
Granbury	278	693	53	1.57
Others (not top 4)				
Ray Hubbard	916	435	47	0.84
Mountain Creek	800	457	55	0.78

*MW - Megawatt

**Water level loss in feet during the summer months of 2011

In the Lower Colorado river basin the system is operated slightly different in that two reservoirs, Buchanan and Travis, are the main resources behind the operation and health of all the other reservoirs in this system. In essence these two reservoirs keep all the other six reservoirs at a stable level. This means that those two reservoirs have highly variable demands as can be seen by the two values in water level loss on Table 3 for Lake Buchanan of between 0.8 feet per month during normal demand and 5.5 feet per month during releases to other reservoirs and downstream users.

Table 3. Lower Colorado Reservoirs with Power Generation – Demand Indicators

LAKE	MW IMPACT	WATER LEVEL (ABOVE MSL*)	RESERVOIR TOTAL DEPTH (FT)	WATER LEVEL LOSS PER MONTH (FT)
Buchanan	54.9	991.84	82.5	0.8/5.5
Inks	13.8	887.18	44	n/a
LBJ	480	824.6	32	n/a
Marble Falls	41.4	736.44		n/a
Travis	108	631.03	145.1	1.7/6.8
Austin	17	492.15	30.8	n/a
Bastrop (Sim Gideon, Lost Pines)	1,119	448.94	60	n/a
Fayette (FPP)	1,625	389.82	70	n/a

* mean sea level

The loss of water level per month was calculated from a four to six-month period between May 1, 2012 and December 1, 2012, determined by the most consistent declines. There are a number of interesting results. For example, Lake Ray Hubbard is within the Dallas-Fort Worth (DFW) area, but has significantly lower water level decline compared with others nearby. This is due in part to the extra municipal and industrial use from those reservoirs, but it can give an indication of the time available before water supply in that specific water body may become critical.

In the western regions of the ERCOT service area there are still a few reservoirs which were relatively low throughout 2012 and into 2013 and need to be assessed on a regular basis. Some of the generating lakes at low levels as of April, 2013 are shown on Table 4.

Table 4. Texas Lakes with Low Reservoir Levels in April, 2013

LAKE	MW IMPACT	VOLUME (AFT*)	% FULL (DEC-12)	WATER LEVEL LOSS PER MONTH (%)
Colorado City	407	31,805	29.1	0.8
Kemp/Diversion	650		22	
Champion Creek	-	41,618	11	0.8
Within the Previous Twelve Months				
Texana	920	159,640	34.2	2.8
Lavon	406	456,526	47.6	1.8
Limestone	1689	208,015	49.7	3.3

*AFT – acre-foot (325,851 gallons or 1 acre to the depth of one foot)

In some of the cases above the generator may have additional water sources to supplement the reservoirs, or else may have other technologies in place to reduce water use. These factors need to be included in any analysis of water availability risk. Examples of power generation units that require a river feed with an off-channel reservoir as the storage medium can be found at a number of locations. These systems will often have a flow minimum recorded in cubic feet per second which will be the driver for water availability. Examples include Lake Bastrop and Lake Fayette as shown on Table 5. The variations shown in this table outline that the withdrawal limits have not been reached to date. However, there has been a trend of declining stream flow over the past ten years which suggests that this may become more of a problem into the future.

Table 5. Stream flow and Withdrawal Limits

RIVER	MW IMPACT	LIMIT (CFS*)	MAY 2013 (CFS)	MIN IN 2012
Bastrop (Lost Pines)	1,119	120	489	190
Fayette	1,625	-	809	318

*CFS – cubic feet per second

2.7 AIR TEMPERATURE

While air temperature is not directly connected to the subject matter of this report it is important to review it in the context of rating and derating of generation facilities. Figure 4 shows an air temperature variation diagram to outline that as the temperature increases above 45°F, the efficiency of a normal system declines. Design points can be altered to change this dynamic, so this data should be used as a guide rather than an exact analysis.

Often there is a mix-up of understanding regarding normal temperature derating (which happens whenever the temperature fluctuates from the design temperature) and when a unit is affected by drought. The year 2011 in Texas was the hottest year on record (approximately 1 degree hotter than any previous year). This would obviously have an effect on the output efficiency of generation facilities. However the connection between the drought and overall temperature increase is difficult to accurately model and has not been attempted in this analysis. It is however, an item that needs to be considered in the future. As an example, if the temperature variations were all causing reductions in efficiency then the overall MW capacity of the combined cycle power plants may reduce by about 0.2%, or 1 MW for every 500 MW of capacity. Since the story is more complex than this simple example the temperature effects of the drought have not been addressed at this time.

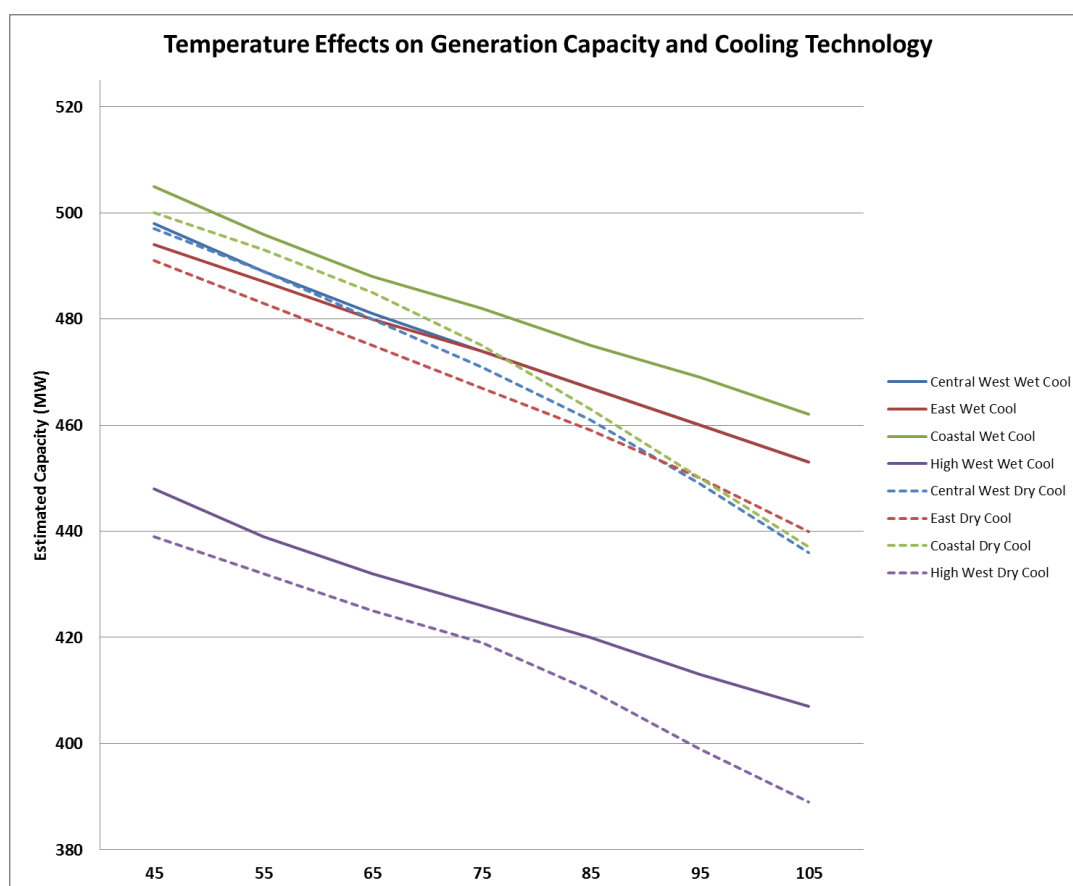


Figure 4. Air Temperature Effects on Power Generation Capacity and Cooling Technology

2.8 WATER RIGHTS

Texas' surface water is owned by the state. The TCEQ issues permits to applicants on a "first-in-time, first-in-right" basis. A permit does not guarantee that water will be available; it only means that the permit holder is in line to use it. Owners of the most senior rights (the oldest permits) can take whatever water is available up to the permit limit. The remaining water is apportioned in sequence to the holders of junior rights. When drought conditions reduce the amount of available surface water, generally only senior rights can be exercised, although if human health may be affected by a specific allocation, then these can currently over-ride more senior rights if deemed appropriate by TCEQ.

To acquire a water permit an applicant must prove that water is available, that the use is consistent with state law and, occasionally, that a defined amount of water has been obtained consistently from a known source, even if that use pre-dates the permit system.

Texas' groundwater belongs to the owners of the land above it, unless the groundwater rights have previously been severed and held separately from the land. Under the legal "rule of capture," landowners or groundwater rights owners are entitled to pump as much groundwater as they are

able to, as long as the use is not malicious or wasteful, even if pumping it deprives other landowners of water. Once pumped, groundwater may be used or sold as private property.

As of 2013 the state currently had approximately 100 groundwater conservation districts (GCD), which were created under state laws and are governed by locally elected board members. GCDs are allowed to develop well spacing rules, pumping permits, fees and overall pumping limits within their districts. Under Texas law, GCD enforcement of its rules is one of only two ways to limit groundwater pumping in an area; the other is a judgment in Texas courts, although the Edwards Aquifer Authority and the Harris-Galveston and Fort Bend Subsidence Districts can restrict pumping within their statutory boundaries.

2.9 POWER GENERATION CAPACITY AND WATER USE

Water demand is driven by the technology used to generate electricity as well as the power demands of the population in the ERCOT region. There is an economy of scale associated with generator facility size, whereby the larger the facility, often the lower the water use per MWh (compared to a similar small system). Also, the cooling design can have a significant impact on water use with a significant difference between once-through and recirculating cooling towers as an example.

Another discussion centers on the water withdrawal versus water consumption. Figure 5 shows the water withdrawal versus nameplate generating capacity for a number of Texas facilities. As would be expected the larger facilities tend to withdraw more water. However, the water consumed per kWh (Figure 6) is actually less for these larger facilities.

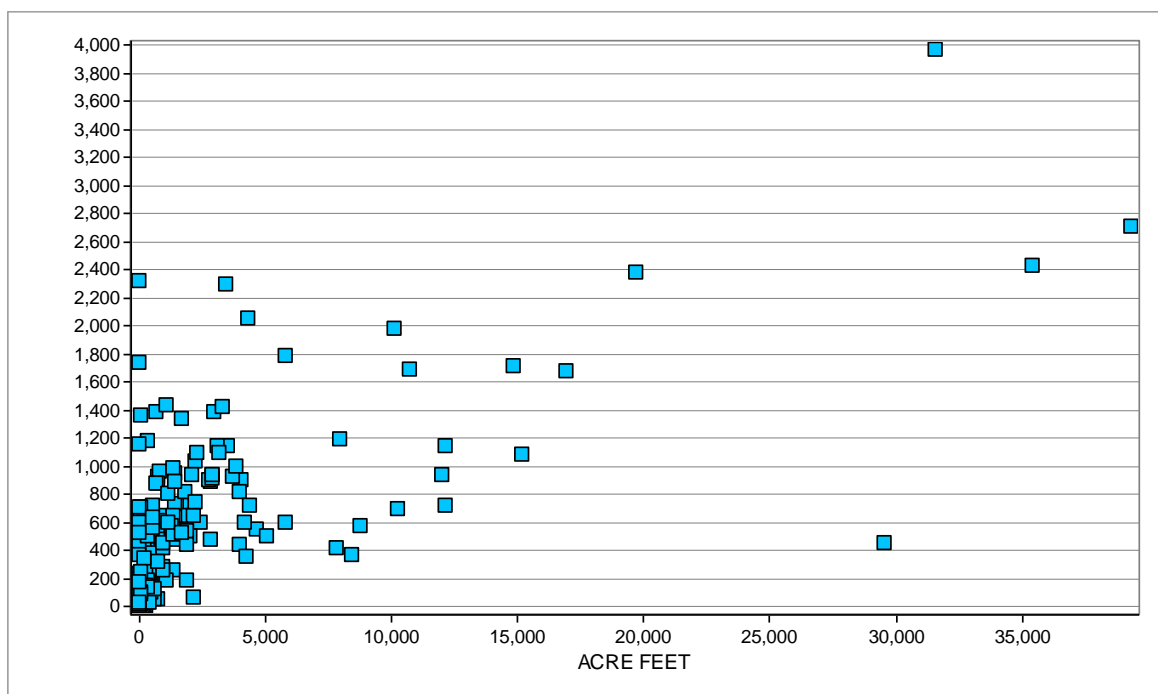


Figure 5. Capacity versus Withdrawal (Acre-feet)

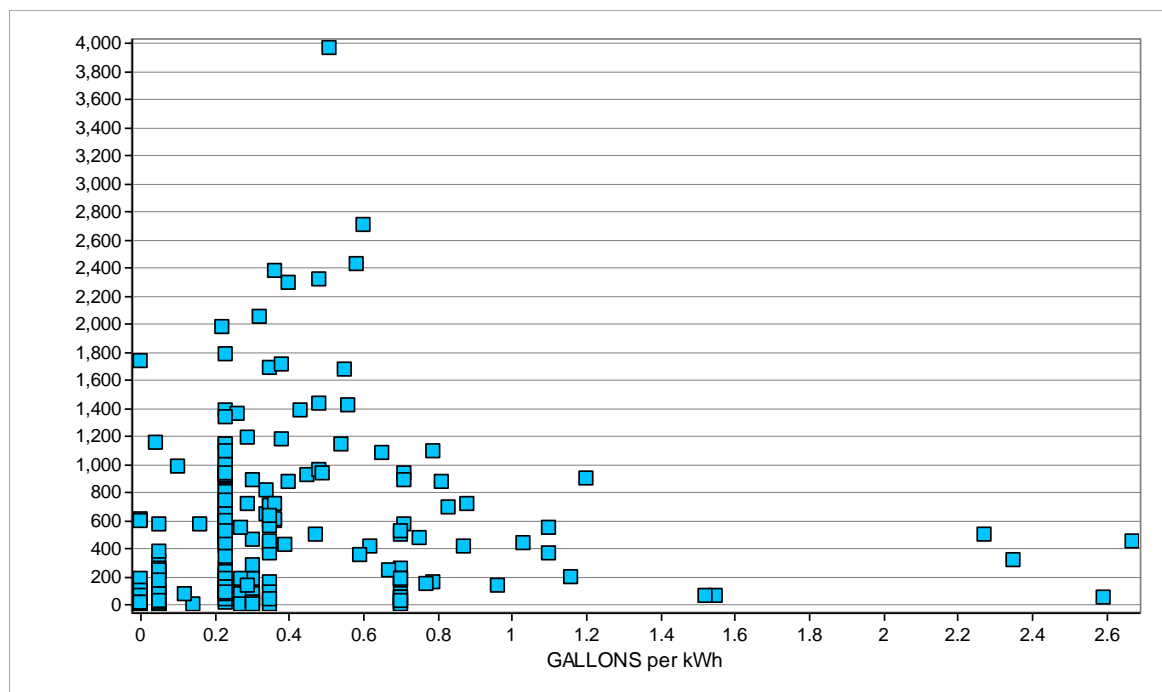


Figure 6. Capacity versus Usage (Gallons per kWh)

As mentioned previously the cooling methods are the driving force behind water use, but capacity can be a contributing factor. The demand for energy from a specific power plant can also affect the water use characteristics as a high nameplate capacity unit only used for peak supply will also use an increased amount of water per kWh compared to a unit that is run constantly and fine-tuned to make the water use more efficient.

2.9.1 Cooling Methods

There are many manufacturers of cooling systems for each power generation unit type. Therefore we will only discuss overall system dynamics, ranges of water use and needs of the different cooling methods. Figure 7 shows some of the various cooling methods and ranges of water use that have been recorded by the National Renewable Energy Laboratory (NREL). The chart outlines the water consumed per MWh (side axis) produced by each of the different generating technologies and cooling systems (base axis). The box and whiskers plots outline the total range of the data set and the 25th and 75th percentile values in the box which outlines most of the data points.

The amount of cooling required by any steam-cycle power plant (of an equal size) is determined on the whole by its thermal efficiency. Water consumption variations among power technology types are thus directly related to the efficiency of the system.

The most common types of power plants use water for cooling in two ways: to convey heat from the fuel source to the steam turbines, and to remove and dump surplus heat from this steam circuit. In any steam/ Rankine cycle plant such as present-day coal, natural gas (steam) and nuclear plants there is a loss of about two thirds of the energy due to the intrinsic limitations of turning heat into mechanical energy.

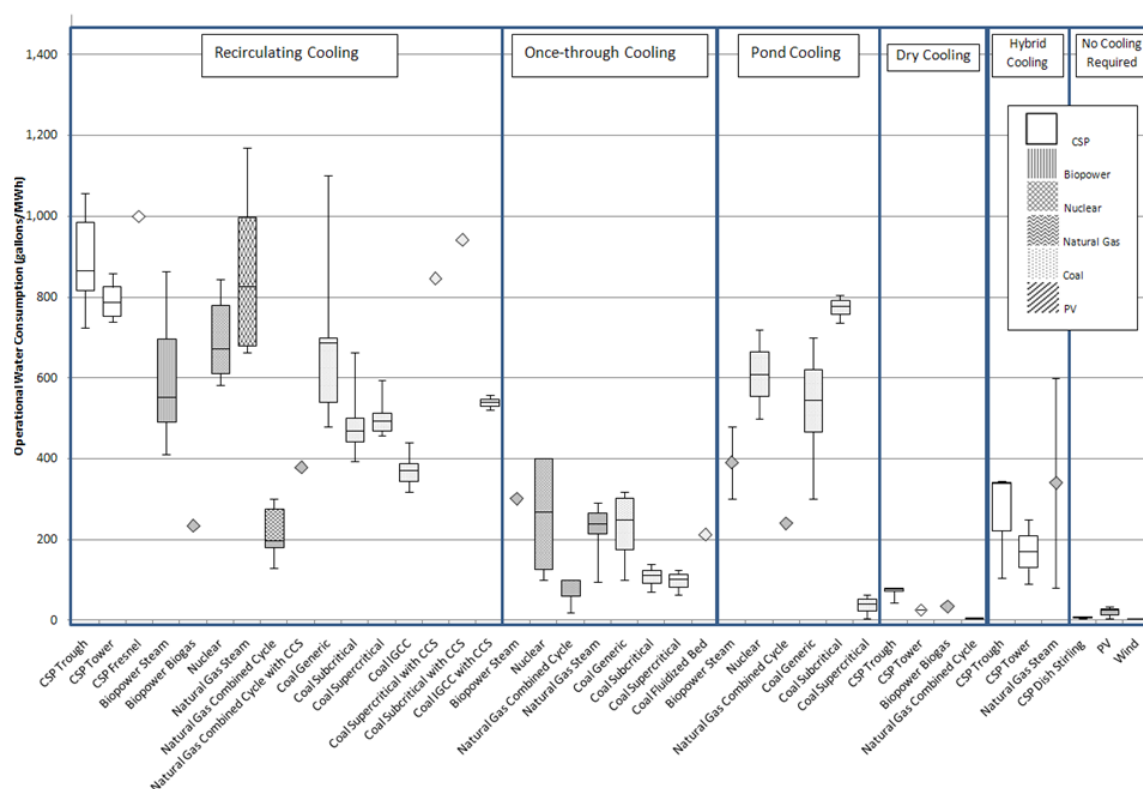


Figure 7. Power Plant Cooling Water Usage Variation (Source: NREL 2011)

The bigger the temperature difference between the internal heat source and the external environment where the surplus heat is dumped, the more efficient is the process in achieving mechanical work and generating electricity. It is therefore desirable to have a high temperature internally and a low temperature in the external environment. This consideration gives rise to the desire to site power plants alongside very cold water, although this is often not possible in Texas. This is also the reason why many power plants have higher net output in winter than summer due to differences in cooling water temperature.

Dry- or air-cooling is being considered as a method to reduce the strain on water resources. While air-cooling has generally higher costs and reduced efficiency relative to other cooling technologies, water use is significantly less (but not zero) as shown in Figure 8.

			Cooling Technologies – Water Consumption (gal/MWh)				
			Open-Loop	Closed-Loop Reservoir	Closed-Loop Cooling Tower	Hybrid Cooling	Air-Cooling
Fuel Technology	Thermal	Coal	300	385 (±115)	480	between	60 (±10)
		Nuclear	400	625 (±225)	720	between	60 (±10)
		Natural Gas Combustion Turbine	negligible	negligible	negligible	negligible	negligible
		Natural Gas Combined-Cycle	100	130 [†] (±20)	180	between	60 [†] (±10)
		Integrated Gasification Combined-Cycle	not used	not used	350 [†] (±100)	between	60 [†] (±10)
		Concentrated Solar Power	not used	not used	840 (±80)	between	80 [†] (±10)
	Non-Thermal	Wind	none	none	none	none	none
		Photovoltaic Solar	none	none	none	none	none

[†] Estimated based on withdrawal and consumption ratios

Figure 8. Cooling technologies and their water consumption (Source: Energy-Water Nexus in Texas, UT Austin, EDF, 2009)

A report from Texas IOU's (2003) outlined the basics of dry-type cooling towers. At the time these were not heavily considered as a method to cool facilities, however this is not the case today. The following is an excerpt from that report.

“Dry-type cooling towers are very expensive and infrequently used, though they are becoming more common in desert climates where water supplies are severely constrained. Because the heat is dissipated directly to air by conduction and convection rather than by evaporation as in a wet-type cooling tower, much more air must be moved through the dry-type tower and the available heat transfer surface must be very great. Both of these factors greatly increase the power requirements of these towers, because of the power needs of the fans utilized to move air across the cooling coils. In addition, the minimum cooling temperatures achievable in dry-type towers are limited by the dry-bulb (rather than the wet-bulb) air temperature, which results in higher turbine exhaust temperatures. In the warmer parts of the country this places a severe penalty upon the efficiency and capability of the power plant. Because of their substantially greater energy and capital cost, it is unlikely that dry-type towers will be used to any great extent in this country in the near future.”

These cooling technologies are being considered seriously in 2013, as technology has improved and water resources have become more of an issue. The efficiency issues are still valid, but dry-type cooling warrants further consideration.

2.10 POPULATION CHANGE

The population of Texas is one of the main driving factors for energy demand in the state. It will both drive residential demand and the industrial demands as these are usually sited in close proximity to the population workforce. The data in Figure 9 outlines the projected change in population between 2012 and 2030. Since residential demand causes the peaking of the current ERCOT system this population profile also suggests the peak demand needs will continue to grow in

North Texas, Houston, and Austin-San Antonio. In addition the lower valley area will also increase significantly with respect to demand. This assumes that the residential demand is a proxy for the total energy demand profile.

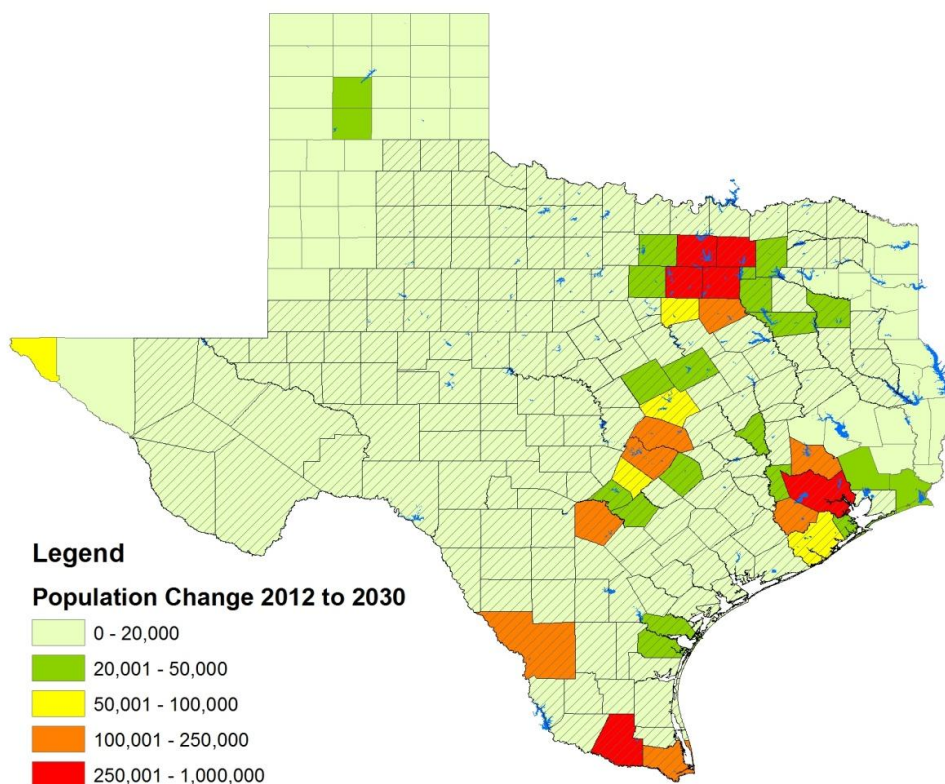


Figure 9. Population change by County (2012 to 2030). (Developed from TWDB TexasCounty_gcsnad83 shapefile)

However the main reason for discussing population increases is to evaluate the competing demands for the water resources in the state. Those areas within 60 to 90 miles of the main population growth centers will likely be affected as municipalities utilize a greater proportion of the resources in a reasonable proximity to meet their demands. This will drive the reservoir demands higher overall and may bring power generation facilities to critical decision points earlier in the planning cycle.

2.11 WATER AVAILABILITY

Water availability has been studied extensively within Texas, from the high-level state water planning to very detailed hydrological modeling of individual stream segments. For this study the Sandia analysis has been utilized to aid with determination of the water availability within the hydrologic basins (at the Hydrologic Unit Code [HUC]-8 level, which is the sub-basin or 4th level of hydrological analysis) in Texas during drought conditions. There is little reported un-appropriated water (water that has not already been allocated to a certain permitted user) in the Texas basins and this is only in the most easterly and southern parts of the state as outlined in Figure 10. Even though most of this area is actually outside the ERCOT boundaries, this resource should still be

considered as there are already some of the power generators that already access their water from the most easterly basins such as from Toledo Bend reservoir.

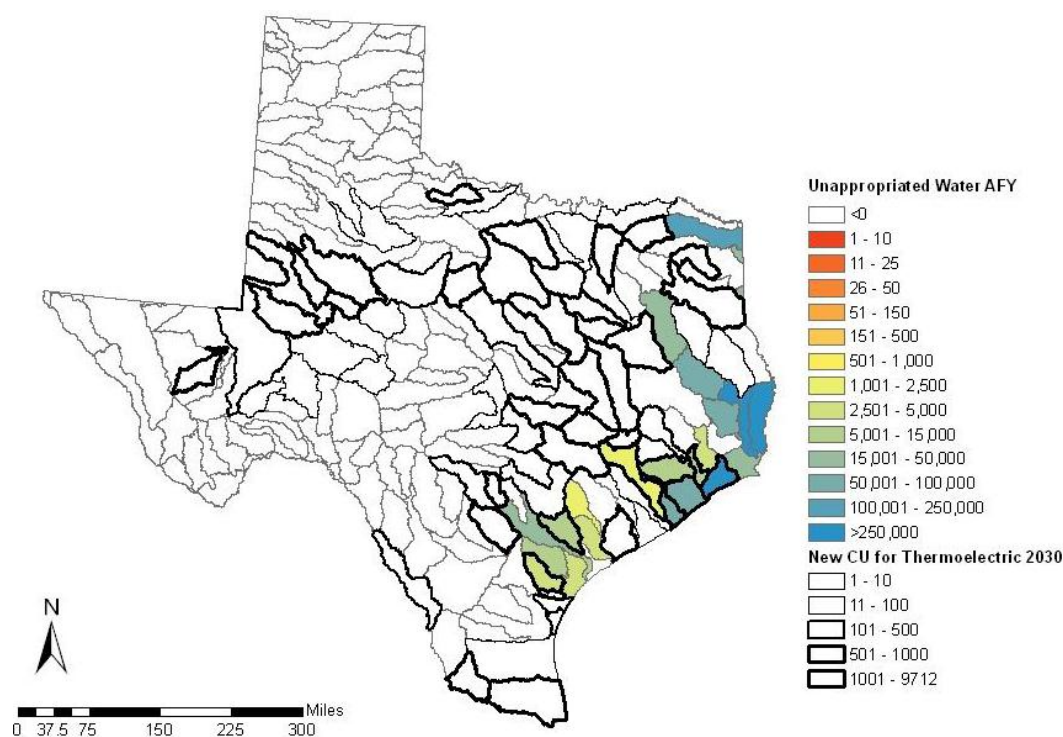


Figure 10. Un-appropriated water availability by river basin in Texas (Source: Sandia Report 2013)

3 2011 Drought Literature Review and Analysis

The 2011 drought in Texas and recent droughts in other parts of the United States spurred a number of entities into conducting modeling and analysis of drought effects with respect to power generation. The following is a basic review of a selection of those reports and review of current drought information for ERCOT.

3.1 DEPARTMENT OF ENERGY SPONSORED REPORTS (SANDIA AND ARGONNE NATIONAL LABS)

The report developed by Sandia and partners (the “Sandia study”) was evaluated by Black & Veatch as part of two reviews provided for the Sandia team that recommend changes in direction and additions to improve the product for the client (ERCOT). The Sandia study covered both WECC and ERCOT (therefore most of the western half of the United States), however, the Black & Veatch analysis only covered the ERCOT area.

Additionally Black & Veatch examined the water supply availability analysis by cross-referencing data against the State water plan and generator survey data (as well as staff knowledge of the project area and expected outputs) to evaluate if the drought outputs matched some expected criteria. This included looking at annual and monthly rainfall patterns, reservoir/lake levels and withdrawals, and surface water temperatures.

The data was then incorporated into the ERCOT evaluations for analysis of system drought conditions and effects, as appropriate.

3.1.1 Basin Data Evaluation

The period of record data was evaluated, and then a drought scenario analysis was conducted. This initially utilized a percentile record matching rainfall/runoff data from historical profiles with similar records. After consideration of regional drought and climate differences the decision was made to match the records from the drought of the 1950s as a proxy for the worst conditions in the period of record and to match a multi-year drought scenario. The year 1956 was the end of the drought of the 1950s, so this was generally used as the worst case year for the drought scenario analysis.

Initial review was conducted on the 2011 drought and reservoir storage and inflow baselines derived through the hydrologic models to give an indication of the extent of the most recent drought. Figure 11 outlines the distribution of reservoir storage modeled from the 2011 drought in the basins with thermal power generation. The red sub-basins on this figure have the lowest storage capacity, and are thus considered the most problematic given 2011 drought conditions.

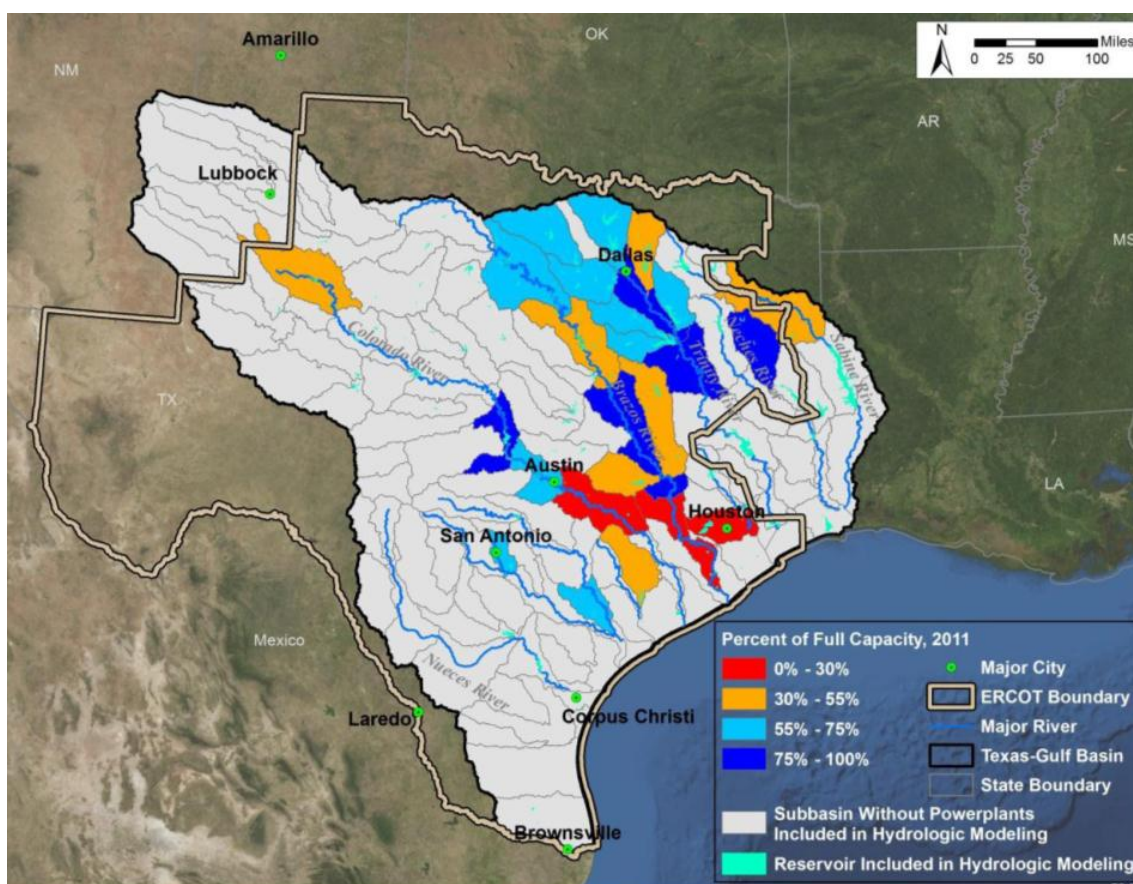


Figure 11. The distribution of reservoir storage that are supporting power plants in HUC8 basins.

Percentage at each HUC8 basin represents the reservoir with the lowest storage in 2011 (Source: SNL Financial. Future climate projections impact on ERCOT thermal generation, Figure 31. 2012).

A negative value indicates that a HUC8 basin in 1956 contributes less water to stream flow than in 2011, and vice versa. (Source: Sandia National Labs Report: Future climate projections impact on ERCOT thermal generation, Figure 40. 2012).

The same hydrologic information was then utilized to develop the basin characteristics in the 1950s drought for those basins with steam electric power generation (Figure 13). The predicted reservoir storage was developed to 2030 water use using demand projections as provided by the Texas Water Development Board (TWDB).

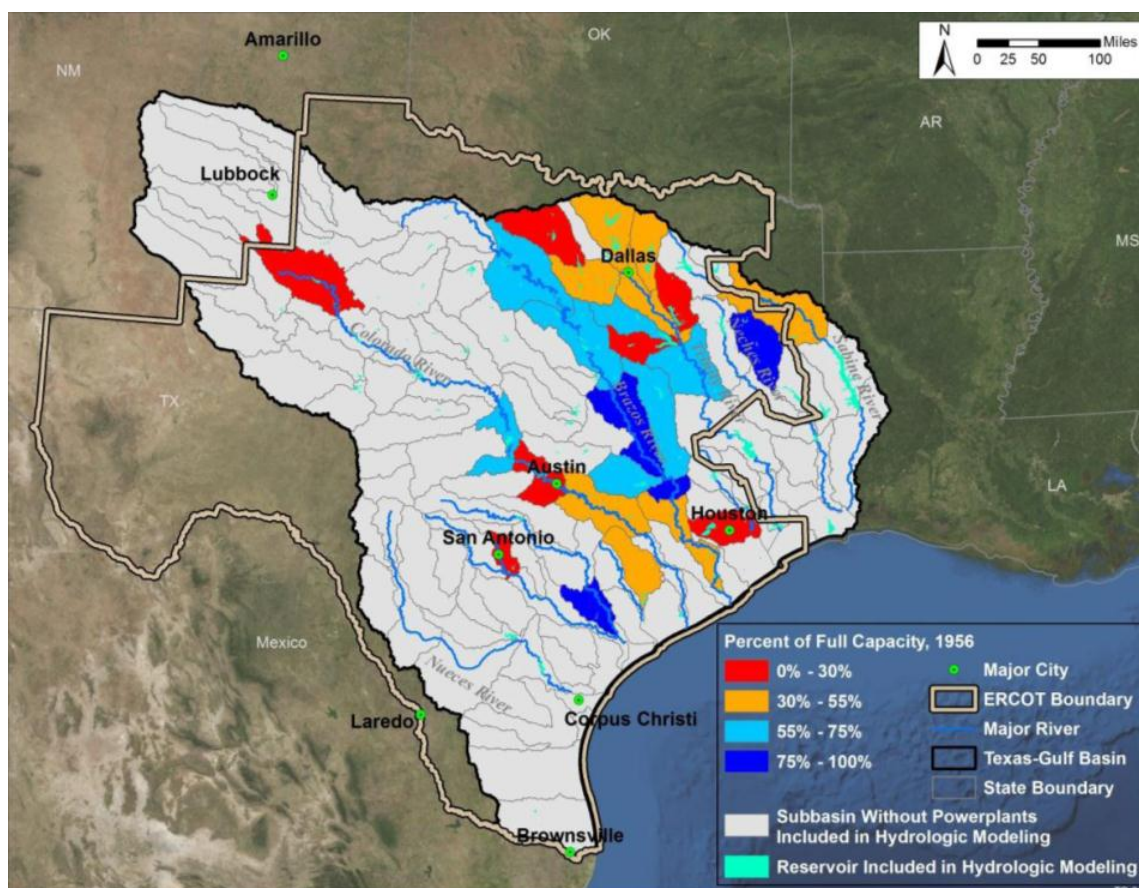


Figure 13. The distribution of predicted reservoir storage that would provide water supply to power plants in HUC8 basins under a long-term drought scenario with assumed 2030 water use.

Percentage at each HUC8 basin represents the reservoir with the lowest storage in 1956 for the multiple-year drought scenario (1950-1957). (Source: SNL. Future climate projections impact on ERCOT thermal generation, Figure 34. 2012).

This analysis suggested a significant problem in the north Texas and Lower Colorado drainage basins. It should be noted that the complexities of inter-basin storage, transfers and secondary water sources was not considered in its entirety in the Sandia study. Pipelines connecting reservoirs, or municipal return flows were not specifically considered. These were not studied in detail within the Black & Veatch study either, although some considerations such as the significant reservoir interconnections in the north Texas region were reviewed in order to provide better projections for this region.

3.1.2 Water Temperature Variables

In addition to the water availability part of the equation, water temperature was also deemed to be a possible factor in potential reductions of power generation availability. Analysis was conducted on most of the sites that have a pond or reservoir utilized for cooling purposes. Temperature limits (if considered) were included in the modeling and predictions of when specific generation units would exceed these limits were identified. Since average air temperature across Texas were the highest on record in 2011 (Source: John Neilsen-Gammon, State Climatologist), it was anticipated that 2006 to 2011 would be a good period of record to analyze. In only three cases were units

determined to be above the temperature limits within the period of analysis (2006 to 2011) and these were not modeled to become major outages due to short run-time of temperature exceedance and also due to re-evaluation and short-term increases in the limits (for entities that have reached these limits in the past) after consultation between the generator and regulator (TCEQ).

In future prediction it is logical that more units may get close to their upper limits. However, it is not expected that this will cause a significant number of units to have to derate at the same time (with current knowledge). An example graphic from the report showing the Handley facility in Tarrant County is shown below. Note that the temperature does not exceed the limits on this graphic.

Figure 14 shows the temperature variations and associated electricity generation (grey line) evident at the Handley units on Lake Arlington in North Texas. While the effluent temperature limits have never been reached temperatures do appear to be rising and therefore need to be evaluated annually. This is also a water supply reservoir and so there is extra caution necessary when considering the temperature of the supply.

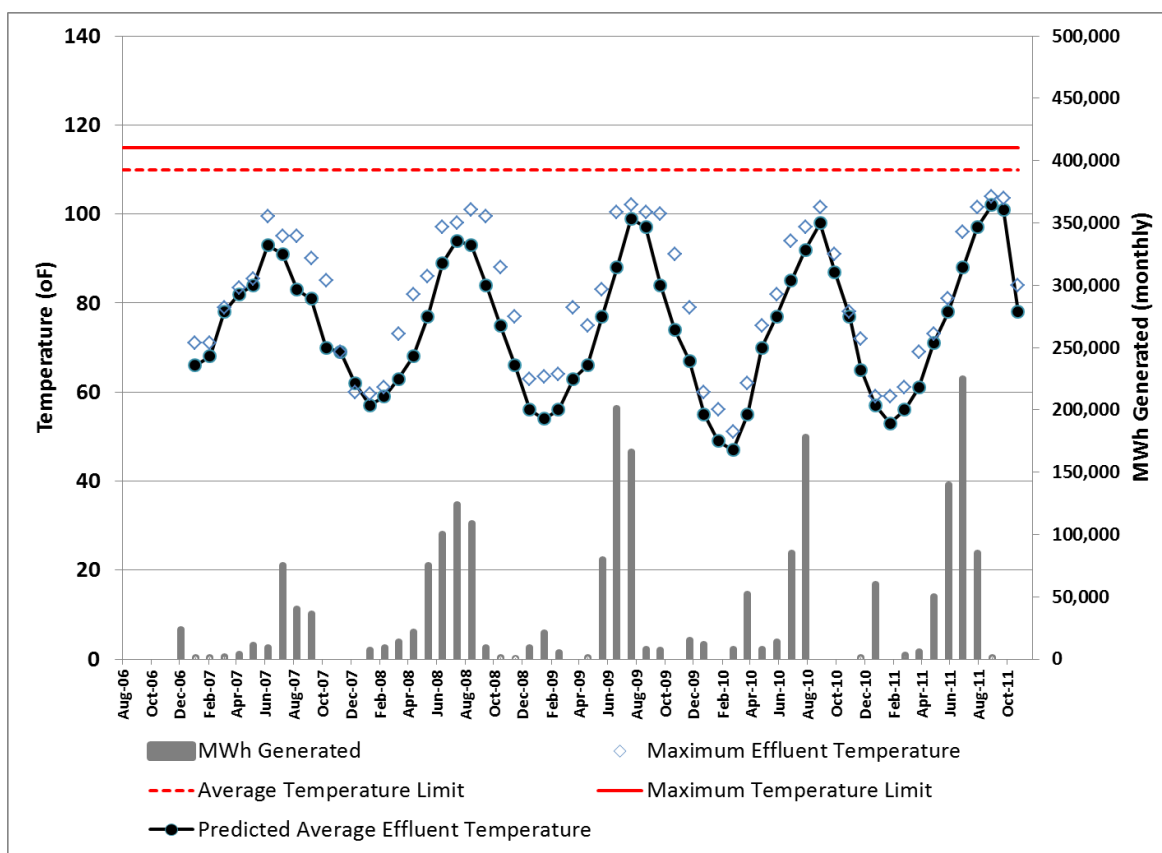


Figure 14. Reservoir Temperature variations and limits for Handley generating plant.

Source: Sandia National Labs (graphic re-configured). Future climate projections impact on ERCOT thermal generation, Figure A23. 2012). The grey line shows the electricity generation, whereas the black line shows the predicted temperature.

3.2 SINGLE-YEAR DROUGHT

The Texas Gulf Coast basin in the Sandia modeling, showed a 25% loss of generation, almost entirely from lost thermoelectric generation. This risk appears to be driven by the extreme nature of the drought in this basin, with drought flows equaling only 31% of normal levels. In addition, over 70% of electricity generation in this basin relies on fresh surface water for cooling. This is in our opinion an overestimate due to the lack of consideration of secondary sources and storage potential in specific basins.

The remaining basins in the WECC model all show total losses of around 5% or less, which indicates that risk from drought in these basins may in fact be small, at least under the relatively frequent 10th-percentile drought conditions. The factors of water storage were not fully included in this model so it needs to be revisited. In the Black & Veatch analysis it was determined that while there still is risk, there was significantly less risk than initially identified due to the storage and secondary supplies that generators had already included.

In the cases of the upper portion of the Brazos, Lower Colorado, San Antonio, Nueces and Rio Grande basins, which are mostly arid and prone to drought, this result of few anticipated problems during a single-year drought such as 2011 may be somewhat surprising. However, this result is due to the fact that shortages of water historically have already forced generators in these basins to think about water and either maximize their storage and/or minimize their water footprint and drought risk. In most basins, the risks to hydroelectric generation outweigh the risks to thermoelectric generation, but the former is limited by the relatively small fraction of total generation from hydroelectric sources in most basins.

3.2.1 Multi-year Drought

Since the single-year drought did not have any significant and noticeable effect on power generation in Texas the multi-year scenario was developed. A logical progression is that as drought conditions worsen the risk of generation unit derate and failure will increase as generation units become more inefficient and the risk for total outages increases. This logic was matched by the calculated data used to develop the risk and derating models.

3.2.2 Integration of Data and Analyses into ERCOT Operations

While there are not specific tools that can be transferred directly into the ERCOT structures at this moment, the data behind the analyses are being used to model future drought problems and possible generation issues. Also the water availability modeling can be used to aid with future generation and transmission strategy.

There are at least three tools or data sets which can be modified or utilized from the Sandia study for more detailed use by ERCOT.

- The temperature modeling, such as that noted in Figure 14.
- GIS data for analyzing sub-basin hydraulic characteristics
- Reservoir storage and stream flow data for future detailed water resource and availability modeling.

The detailed information on temperature characterization and modeling is a good indicator of possible issues in the future. As lake levels reduce and the heat-sink capacity of the reservoirs diminishes, the risk of outages will increase. In addition the basin modeling has created a basic database of costs and availability per sub-basin which after validation can be utilized to aid with new development siting and cost evaluations.

3.2.3 Gaps in Information

The Sandia study was designed to evaluate the surface water systems and concentrate on those areas around the current reservoirs and generation facilities. It was also designed initially to be used in both ERCOT and WECC service areas. The ERCOT area was broken up into a separate zone so that the record drought of 2011 and evaluations of the multi-year drought of the 1950's could be properly modeled. The following outlines some of the gaps in the Sandia report that were identified.

3.2.3.1 Groundwater

Groundwater was not considered as a supply source for power generation in the Sandia report. It is not currently considered as a major resource for power generation in Texas. However, future analysis may well include groundwater due to the needs for drought-proofing of power plants and the possibility for desalination and the power requirements (and water use) that those systems will need. As reservoirs become more difficult to build (due to environmental concerns and the lack of good sites) and resources continue to be stretched due to population increase and demand growth, groundwater may become an option.

Since groundwater also has resource limitations, it is possible that it will act as a secondary source in times of drought to alleviate short-term problems. It can also be used as a secondary storage mechanism which has less water lost through evaporation. There are a small number of generators that utilize groundwater in the ERCOT jurisdiction already. While once through cooling systems will not be likely to utilize this resource due to the amounts of water needed to flow into the system, re-circulating cooling tower systems may utilize this resource under carefully engineered conditions.

3.2.3.2 Secondary Supplies

Secondary supplies can take the form of all the forms currently used, except reservoir systems. Groundwater, river intakes, municipal, desalination and reuse supplies can all be utilized. In systems with small reservoir storage, highly variable rainfall, or large risk (such as nuclear facilities) almost all of the power generators with these problems already have a secondary source permitted and operational. In many cases these secondary sources are utilized to keep a power plant lake at a relatively constant level. This will allow more efficient functioning of the system. In many cases this is done through a river intake. However, releases from lakes upstream can also be utilized, such as Lake Buchanan feeding Inks Lake for the Ferguson Power Plant in the Lower Colorado.

Each river system needs to be evaluated in a unique manner in order to truly understand the priorities within a river basin. The Sandia report does show some of the over-arching basin availability surpluses and shortfalls, but it does not include the complexities of river system operation and was never intended to do so. The Black & Veatch report is designed to incorporate some of these nuances, but the reports are in no way trying to replicate this complex hydrological work conducted by the River Authorities.

3.2.3.3 Confidential information

There are a number of pieces of information that the Sandia staff did not have access to. Items such as monitoring, intake, or critical supply levels were often not public information. While this reduces the level of detail possible, the overall premise was to determine the range of drought issues at the basin level rather than to highlight specific generating units.

3.2.3.4 Stream/River Levels

While the Sandia work did include information on the stream gauges as well as reservoir levels, the focus was on basin storage and reservoir information. The stream intakes and associated environmental flow requirements were not considered in detail within the report.

3.3 LONG TERM SYSTEM ASSESSMENT

With this information ERCOT staff developed three scenarios to include in the Long term system assessment (LTSA) in 2012 to analyze the effects of a long-term multi-year drought. For these scenarios load forecasts were developed using Moody's base economic assumptions to which the 2011 ERCOT load shape was applied.

The three Drought Scenarios were developed around the business as usual (BAU) All Tech scenario that was studied for DOE Long Term Analysis. The first of the Drought Scenario alternatives had two major changes. First, capacity reductions for all existing thermal generation units were applied during the period of the drought, 2019 through 2025 due to lack of water at existing plant sites and increase in intake/discharge temperatures. Secondly, additional costs for acquiring water for new thermal generation expansion units.

The second Scenario used the first scenario and reduced the expected natural gas price by \$2 per MMBtu for all years. The third scenario added the wind production tax credit and emission costs on all fossil-fueled thermal units.

Final results indicate that thermal, wind, solar and geothermal resources will be added in both the first and second scenario. However, additional wind and solar resources will be added to the ERCOT system in the first scenario because of the added cost of water for thermal units. In the second scenario (with lower natural gas prices) thermal units will be built until the price of natural gas price exceeds \$6 per MMBtu at which point wind becomes more economic as shown in Figure 15.

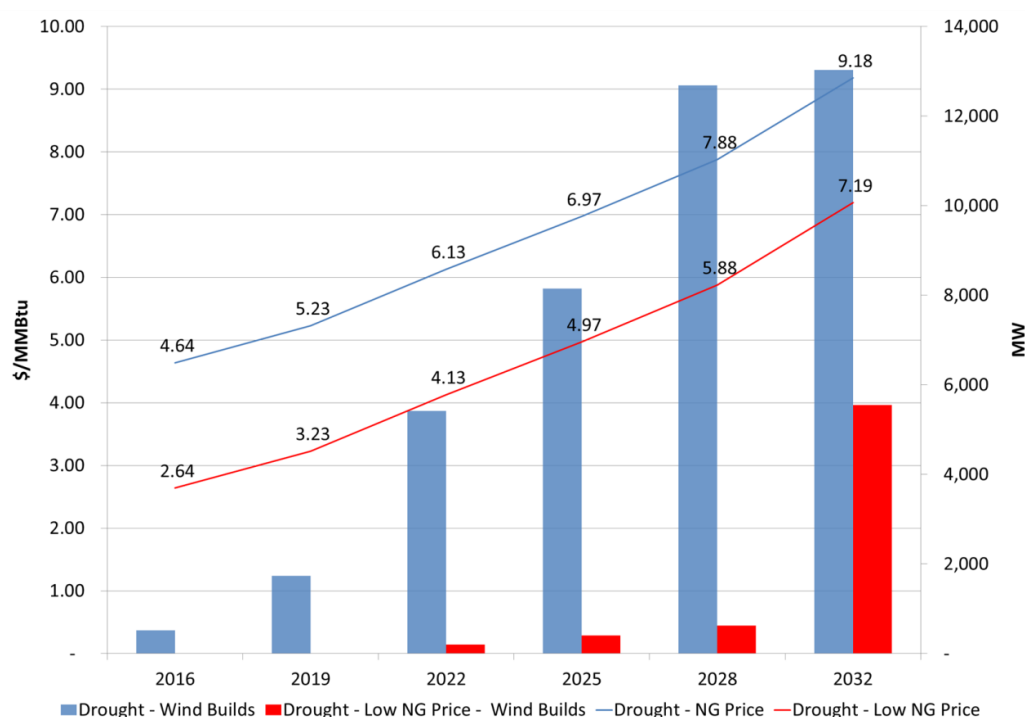


Figure 15. Comparison of Natural Gas price and Wind Build

The costs associated with purchase of water and of the water rights to operate power plants do not currently appear to be a limiting factor to development, so it is unlikely that market forces will drive new generation away from steam thermal plants due to cost. However, the availability of the water resource will certainly be limiting and is a risk that needs to be fully considered.

If rainfall in Texas were all trending toward a reduction in volume then it would be easy to deduce that water availability will decrease proportionately. (the rainfall trends and regional rainfall variations are outlined in greater detail in Section 4.) This not the observed case, as some rainfall monitoring stations in Texas show increasing trends over the period of record since 1900. The current water supplies for power generation were all able to manage through the 2011 drought and there are significant available and un-appropriated resources on the eastern and coastal portions of the state. In addition as will be outlined in section 3.4 the water demand projections for steam thermal generation appear to be significantly higher than will actually be the case. This suggests that as long as the process and technologies used for water cooling are managed carefully and efficiently, this analysis estimates that there are probably sufficient water resources within the state to allow building of additional thermal units with water-based cooling. It is expected that location will be a decision factor, but steam thermal generation should still be possible. This will be further described at the end of this report after discussion of some of the other items that have influence on this statement. All types of units should be considered when determining resource adequacy and siting of new generation units. In addition it is anticipated that there will be geographic considerations for future thermal unit development. The least risk, with respect to water supply is expected in the east and coastal areas and the eastern portions of the central Texas weather zones (north, north central, and south central and the north eastern portion of the

southern weather zone). These areas are expected to be the most conducive for thermal unit development.

3.4 CONSISTENCY WITH THE TEXAS WATER DEVELOPMENT BOARD REGIONAL WATER PLANS

The Current TWDB Water Plan was completed in 2012. This water plan analysis is completed on a five-year cycle. The following subsections review water plan data from some of the main population centers including Houston, Dallas-Fort Worth, Austin and San Antonio.

3.4.1 Power Generation in Texas Regional Plans

The three most important areas with respect to the LTSA were Dallas-Fort Worth, Houston, and Austin-San Antonio. These fall within four regional planning groups (DFW – Region C, Houston – Region H and Austin-San Antonio – Regions K and L).

3.4.2 Dallas – Fort Worth, Region C

The locations of water- and air-cooled generation units for the Dallas-Fort Worth (TWDB Region C) area are mapped on Figure 16. The red dots represent once-through, orange represent cooling towers and blue represents a hybrid system and green represents air-cooled generation systems.

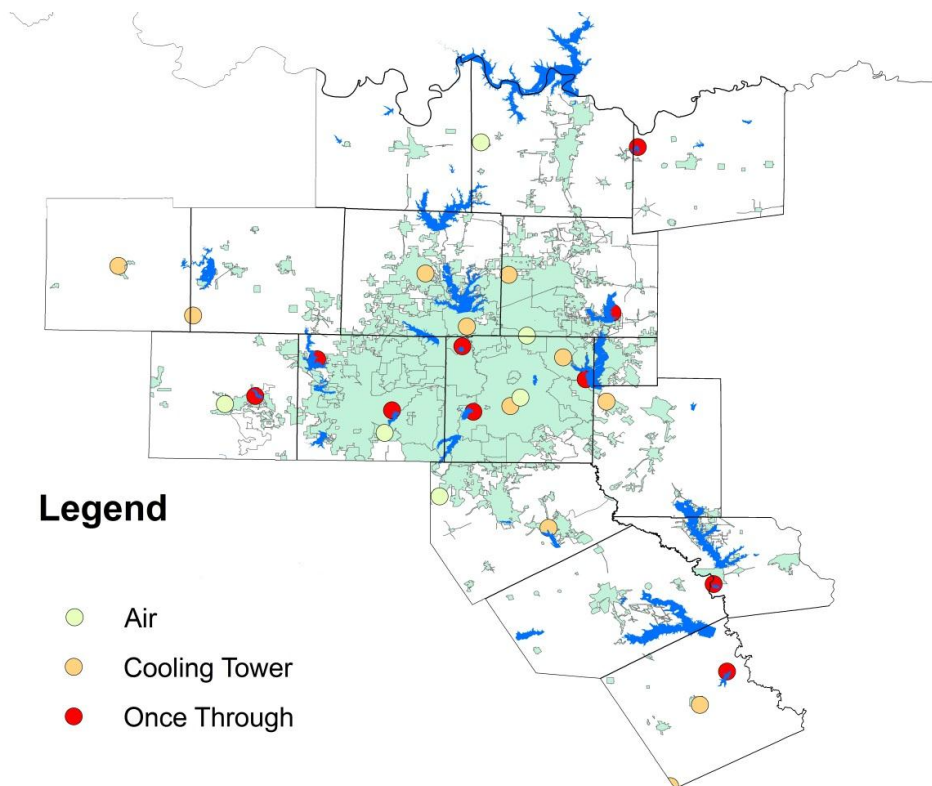


Figure 16. Dallas-Fort Worth Region power generation cooling water consumption

3.4.2.1 Historic Power Generation Water Use

Historically there was significantly higher water use for electric generation. For example in 1980 53,009 acre-feet was used, whereas in 2007 only 15,160 acre-feet was reportedly used. However this did rise to 56,236 for 2000 which was a very hot year with high summer demands. This suggests that most of the generation in the vicinity is utilized for peaking. In 2006 Freestone County was by far the highest water user with almost 60% of the total use. The only other counties with more than 1,000 acre-feet of use were Dallas (3,054) and Tarrant (1,444). This was only 3.5% of the total Texas water use for power generation, although this can rise to almost 10% when peak loads are considered.

3.4.2.2 Projected Power Generation Water Use

Population is estimated to increase by close to 40% between 2012 and 2030 from 6.6 million to 9.1 million, thereby significantly increasing demand in the area. Power generation water use is estimated within the state water plan to increase by 57,000 acre feet per year by 2030.

There are some slight discrepancies in data recorded such as Fairfield Reservoir – TWDB Storage 44,169 acre-feet, Regional Plan 50,600 acre-feet. However, these are relatively minor issues and can be due to different measurement levels rather than actual errors.

3.4.3 Houston, Region H

3.4.3.1 Historic Power Generation Water Use

There is one coal-fired electrical power plant in Region H, the W. A. Parish facility. With a nameplate capacity of 2,698 megawatts, however, this facility is the largest coal-fired facility in Texas. It constitutes 12% of the total coal-fired electrical generating capacity in the State. The estimated annual water use for this facility, based on producing 18 million megawatt-hours of electricity in 2005, is 32,762 acre-feet per year.

The State Water Plan projects a current shortfall of 3,203 acre-feet per year to meet steam-electric water demands. The shortfall is expected to increase to 55,972 acre-feet per year by 2060. However, it is anticipated that this may be an over-estimate due to both the expected increases in renewable generation and more water efficient generation technologies. The locations of water- and air-cooled generation units for the Houston (TWDB Region H) area are mapped on Figure 17. The red dots represent once-through, orange represent cooling towers and green represents air-cooled generation systems.

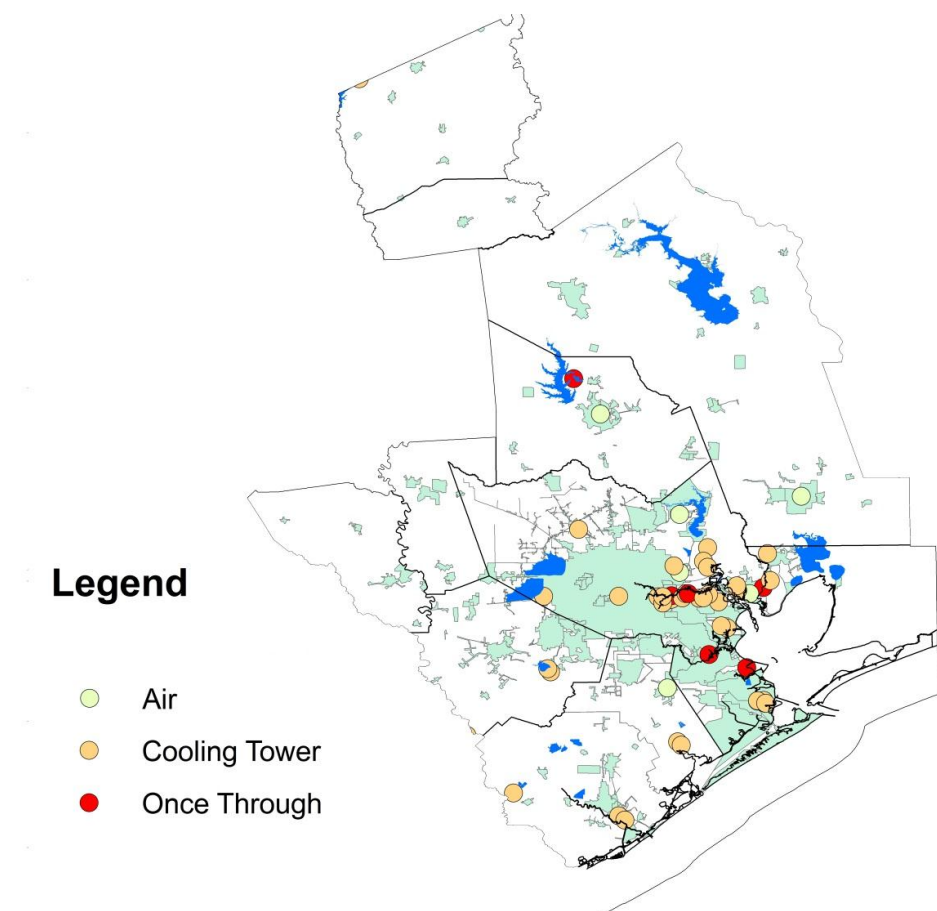


Figure 17. Houston Region power generation cooling water consumption

3.4.3.2 Projected Power Generation Water Use

Approximately 24 percent of the state's population was projected to reside in the region in 2010. By 2030, Region H is projected to grow to 8 million. Total demand for the region is projected to increase 48 percent by 2030. The largest consumers of water in the region are municipal entities, and municipal demand is expected to grow 61 percent by 2060. Power generation water use is estimated within the state water plan within the Houston region to increase by 40,000 acre feet.

3.4.4 San Antonio and Austin, Regions K and L

3.4.4.1 Historic Power Generation Water Use

There is one coal-fired electrical power plant, the Fayette Power Project, located in the Lower Colorado Water Planning Region. This power plant, with a nameplate capacity of 1,690 megawatts, constitutes 7% of the total coal-fired electrical capacity in the State. Based on a 2005 generation of 11 million megawatt-hours, the average annual water demand for this facility is 12,774 acre-feet per year. The J K Spruce, J T Deely, and San Miguel coal-fired electrical generation facilities are located in the South Central Texas region. The estimated combined water usage of these plants is 28,588 acre-feet per year. The locations of water- and air-cooled generation units for the San Antonio - Austin (TWDB Regions K and L) area are mapped on Figure 18. The red dots represent

once-through, orange represent cooling towers and green represents air-cooled generation systems.

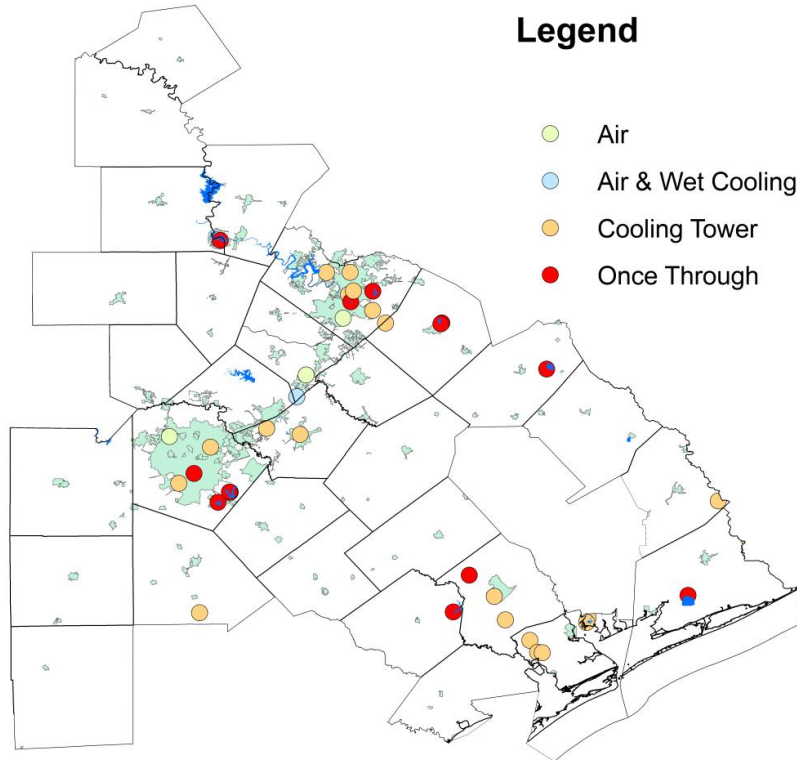


Figure 18. San Antonio-Austin Region power generation cooling water consumption

3.4.4.2 Projected Power Generation Water Use

In 2010, nearly 16 percent of the state's total population resided in the Lower Colorado and South Central Texas Regions combined, and between 2010 and 2060 its population is projected to increase by approximately 90 percent. Water demands, however, are projected to increase less significantly.

Power generation water use is estimated to increase significantly in these two regions combined by 128,000 acre feet per year.

3.5 FUTURE WATER DEMAND

Future demand is difficult to apportion spatially due to such factors as generation well outside the area that can supply electricity to each market. Therefore, future demand is evaluated for the whole of ERCOT. Tables 6 through 9 profile the water demand expectations by Texas region. Population projections from the Water Plan (Table 6) are also shown to allow some analysis of the load to be evaluated with respect to the LTSA studies.

ERCOT | WATER USE AND AVAILABILITY IN THE ERCOT REGION

Table 6. Population Projections (number of people)

TWDB REGION AND MAJOR CITY	2010	2020	2030	2060
C - DFW	6,670,493	7,971,728	9,171,650	13,045,592
H - Houston	6,020,078	6,995,442	7,996,480	11,346,082
K – Lower Colorado (Austin)	1,412,834	1,714,282	2,008,142	2,831,937
L – South Central Texas (San Antonio)	2,460,599	2,892,933	3,292,970	4,297,786
Total ERCOT*	25,383,403	29,650,388	33,712,020	46,323,725

*This currently includes all of Texas.

Table 7. Water Demand Projections (Acre-feet per year)

REGION	2010	2020	2030	2060
C - DFW	1,761,353	2,078,744	2,377,738	3,272,461
H - Houston	2,376,414	2,600,348	2,815,482	3,524,666
K – Lower Colorado	1,086,692	1,180,160	1,231,018	1,382,534
L – South Central Texas	981,370	1,091,573	1,145,898	1,291,567
G - Brazos	870,180	979,223	1,058,290	1,248,514
Total (16 Regions)	18,010,599	19,038,954	19,821,152	21,952,198

Table 8. Electric Generation Water Demand Projections (Acre-feet per year)

REGION	2010	2020	2030	2060
C - DFW	40,813	64,625	98,088	126,428
H - Houston	91,321	112,334	131,332	217,132
K – Lower Colorado	146,167	201,353	210,713	270,732
L – South Central Texas	46,560	104,781	110,537	128,340
G - Brazos	168,193	221,696	254,803	319,884
D NE Texas	89,038	96,492	112,809	186,509
Total (16 Regions)	733,179	1,010,555	1,160,401	1,620,411
Sandia Study (est.)	450,000		510,000	

Table 9. Projected Steam Electric Needs in Acre-feet per Year (2012 Plan, Table 6.3)

REGION	2010	2020	2030	2060
C – DFW	0	13,217	29,696	51,323
H – Houston	3,203	12,609	18,058	55,972
K – Lower Colorado	193	53,005	53,175	89,042
L – South Central Texas	2,054	50,962	50,991	52,018
G – Brazos Basin	38,542	71,483	82,891	132,872
Total TWDB	64,199	261,071	317,998	615,194
Sandia Study (est.)			60,000	

As can be seen from Table 9 above, and comments made during the LTSA discussions, there appears to be a large disconnect between this and the Sandia analysis in 2012. This disconnect may be due to changes in the generation units to more water efficient technologies which will reduce water withdrawal and consumption. For example, to the extent that once-through cooling is assumed, the regional water plans do not appear to consistently account for the water that is returned to the water courses.

Data from 2009 within the State Water Plan records an estimate of 454,122 acre-feet was withdrawn for steam electric uses. This is very close to Sandia projections of 450,000 acre-feet. The State Water Plan projections of 733,179 acre-feet starting in the following year (2010) are significantly higher, but are driven by the drought year demands and the previously mentioned resource mix differences. It appears that this data may need to be re-evaluated and validated as there are significant variations between the two studies as well as differences between Regions within the State Water Plan. For example there are a number of Regions with large increases in water requirements projected between 2010 and 2020 (197,000 acre-feet), but not the same increase between 2020 and 2030 (57,000 acre-feet) as outlined on Table 9. A number of these data points were calculated prior to the natural gas price reductions and significant increases in wind production. Therefore the assumptions will need to be re-addressed in the next planning cycle.

The Sandia Study estimates 450,000 acre-feet of water consumption for power generation in ERCOT assuming 13.2% of generation from wind, or 510,000 acre-feet considering no new wind generation. This suggests almost zero growth in water use if the TWDB 2009 figure can be used as a benchmark. Due to the increase of wind generation, improved efficiency of cooling systems and some shift to lower water-consuming technologies, this projected near-zero water supply demand growth for steam electric power generation does appear possible.

4 Drought in the ERCOT Region

The drought in 2011 was the greatest single-year drought across the ERCOT region, comparable to the drought of 1917, where the average over the whole state was only about 15-inches. However, it still does not match the drought from the 1950s for longevity. In many of the most populous areas such as DFW and Houston, rains in the late spring of 2012 and into 2013 have restocked reservoirs and reduced the water supply issues in those regions. However, the situation can change quickly with reservoir levels dropping by more than two feet per month in some cases.

4.1 STATEWIDE AND REGIONAL VARIATIONS

The statewide variations are significant with some regions much more susceptible to drought issues, and some others in almost perpetual drought. The normal pattern of drought in the west and surplus in the east and south is generally true. However a drought of more than one year can significantly affect resources in the central and southern areas as well due to lack of supply storage and heavy demands in those areas.

Compared to other states the variations in Texas rainfall are very significant. The variation from lowest recorded to average rainfall is 1 to 10 in Texas and only 1 to 3 in California.

Regionally, drought may hit different areas at different times. The year 2011 was relatively consistent across the whole of Texas, but in other years regional areas have been just as badly impacted. For example southern and west central Texas had multi-year drought between 1998 and 2004 as well as during the 1950s.

4.2 DROUGHT YEAR ANALYSIS

This section presents profiles of the most significant drought periods in recorded Texas history. It also evaluates environmental data from pre-history.

Reliance on a single historic worst drought period to portray state-wide conditions can be misleading because the worst drought period may be different among the regions. For example, in most regions, 1950 to 1957 was the most extensive multi-year drought. However, the areas of Wichita Falls to Abilene and the Rio Grande Valley observed worse conditions between 1996 and 2004.

Figure 19 shows one rainfall gage from Cleburne, just to the southwest of the DFW area. While the multi-year drought during the 1950s is apparent at this location, 1963 was actually the worst single-year drought, thus highlighting the localized and year-to-year variability of precipitation. One of the striking items about this graph is that annual average rainfall at this site has actually been on the increase between 1900 and 2011 and the variation overall has also increased over that time.

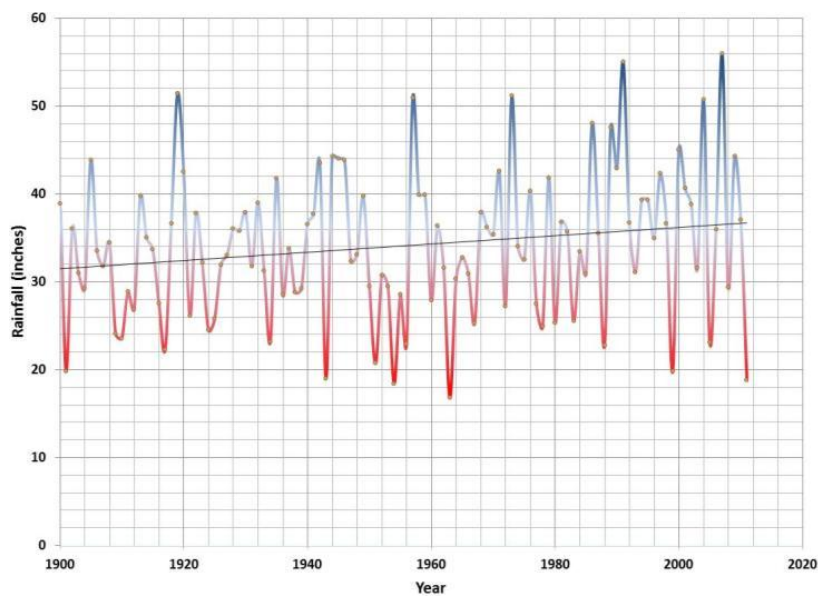


Figure 19. Cleburne Rainfall, 1900 to 2011 (Average 34.01)

4.2.1 Year 1917

Prior to the drought of 2011, 1917 was the worst single-year drought on record with an average of 15-inches of rainfall across the state. Figure 20 from Aransas Pass still shows this as its lowest year of rainfall even compared with 2011.

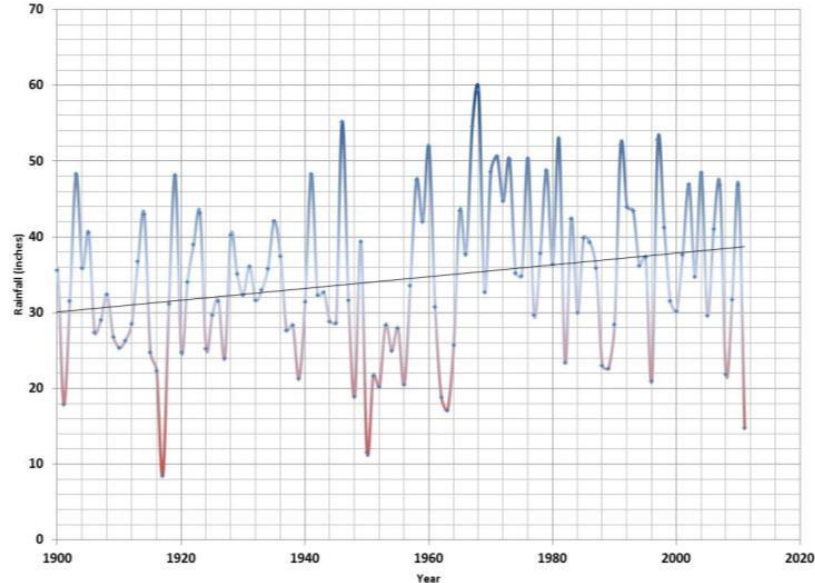


Figure 20. Aransas Pass Rainfall, 1900 to 2011 (Average 34.20)

4.2.2 Years 1950 to 1957

This period was always considered the drought of record in Texas until 2011 and this period is still considered the drought of record for planning purposes. However, since 1950 to 1957 was a multi-

year drought it should still be considered as the most problematic condition as the drought issues are compounded as reservoir storage reduces. In the HUC-8 analyses conducted by the Sandia team it was modeled that the reservoir levels recharged to 100% capacity in 1953. This was true in a number of parts of the state, but not all. However the view of two three-year droughts stacked back to back is probably realistic for much of the central portion of the state. Therefore it only acts as a three year drought cycle rather than the seven years as outlined in many of the texts.

4.2.3 Years 1998 to 2004

Southern and west central Texas had its worst drought with respect to its water supplies between 1998 and 2004. The reservoir levels reduced to less than 10% of usable storage in a number of areas. The 2011 drought is now exceeding this in a number of areas within the state.

4.2.4 Year 2011

This year is reported as being the worst single-year drought in the state over more than 60% of the land area. In some cases it appears that the 2011 drought is worse even than the 2000 to 2004 period, however in most cases these reservoirs never filled and so a comparison on lake levels is difficult to ascertain. Figure 21 from Abernathy in the Texas panhandle shows that 2011 was significantly worse than any other year on record.

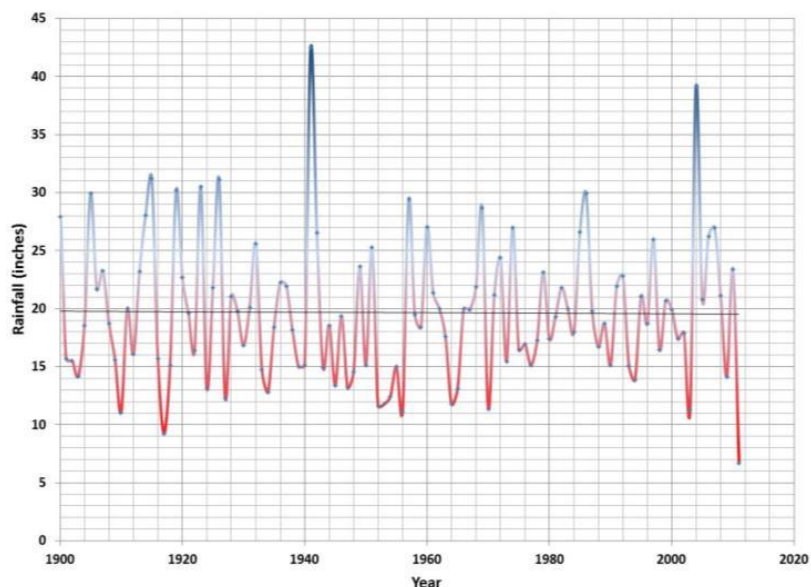


Figure 21. Abernathy Rainfall 1900 to 2011 (Average 19.67)

The three rainfall graphics show a micro-view of the regional variations across the state. When drought hits an area the perception is that the overall average is decreasing too, although this is not always the case. If the average is consistent or rising then there is a possibility that increased storage can smooth over the drought periods. If the overall average is declining, then the storage will not be as effective.

4.2.5 Drought History Prior to Monitoring Capability

The tree ring analysis network, determined using data from Bald Cypress, Post Oak and Pinon Pines within the Texas area has helped to develop drought analyses prior to the times when monitoring was available and operational. This data can go as far back as the ages of the trees. There also needs to be correlation between tree samples and so the current analysis goes back to approximately 1500 AD. There are a relatively small number of calibration sites in Texas (approximately ten). However, the tree ring network gives a reasonable indication of drought severity over the period of record. Figure 22 outlines that the tree ring analysis (red) is a reasonable proxy for the true conditions (blue dotted line). The data in this graphic is from South Central Texas.

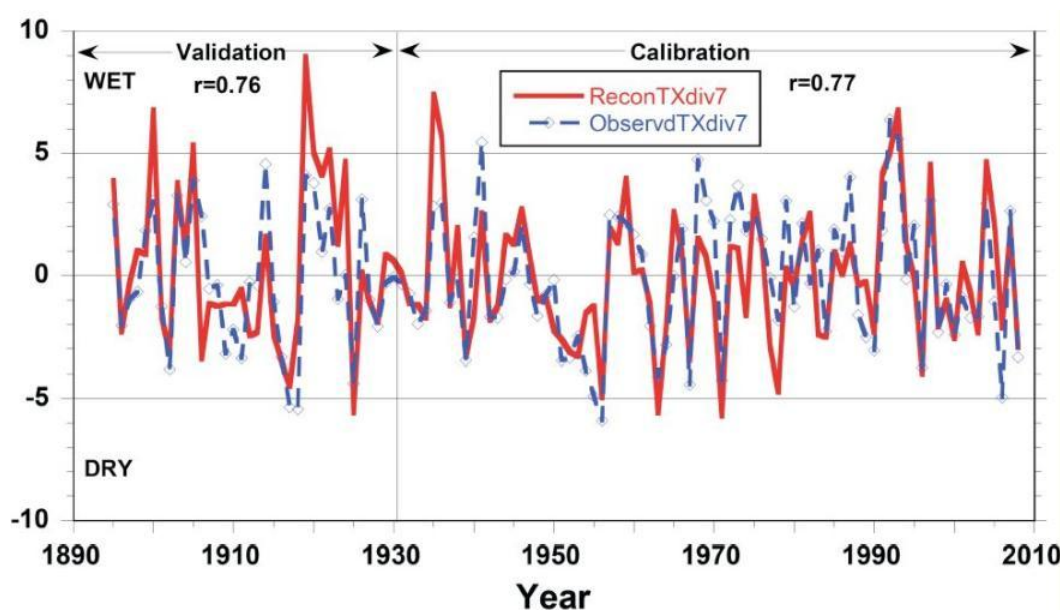


Figure 22. Tree Ring History – Calibrated Period 1890 to 2010

The tree ring data was calibrated using existing monitoring records of rainfall (Source: Cleveland, Malcolm K., Todd H. Votteler)

Daniel K. Stahle, Richard C. Casteel, Jay L. Banner, “Extended Chronology of Drought in South Central, Southeastern and West Texas,” *Texas Water Journal*, Vol. 2, Issue. 1 (2011): 54 – 96.). In Far West Texas the most severe drought since 1500 was actually the drought of the 1950s, whereas in central and southern Texas the worst drought was estimated to be from 1708 to 1717. This shows the regional variations that need to be assessed when viewing the drought data and the fact that the drought of the 1950’s may not be the worst experienced in Texas.

The tree ring data has been extrapolated to drought severity using the Palmer Drought Severity index (PDSi) which is also used for drought monitoring today. However, the tree ring data shown in Figures 22 to 24 only evaluates the data for the summer growth period of the respective year and then uses that as an estimate of the whole year’s relationship to rainfall and drought.

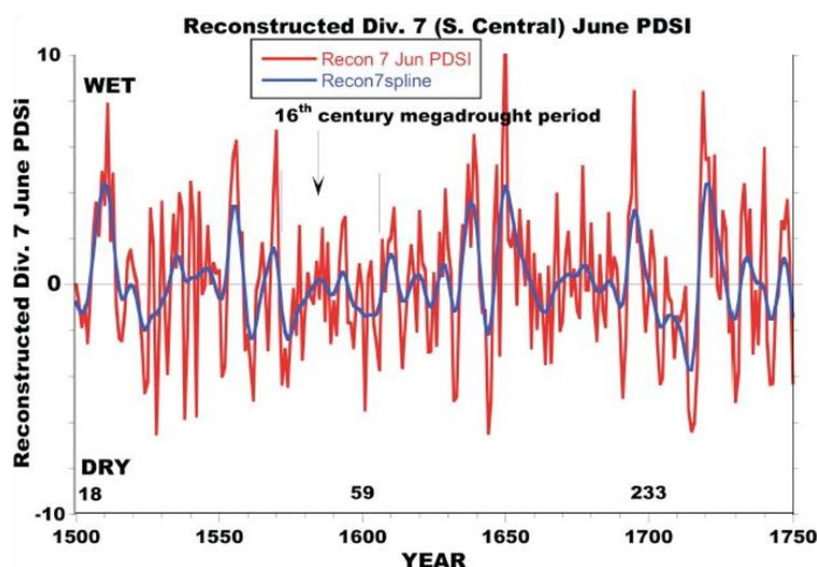


Figure 23. Tree Ring History – 1500 to 1750 (June records only)

There were a number of long-term droughts in the South central area as determined by tree ring analysis. This continued into the period from 1750 to present (especially in the 1850s), but the droughts of the 1950s do not appear to be the drought of record in the south central Texas area.

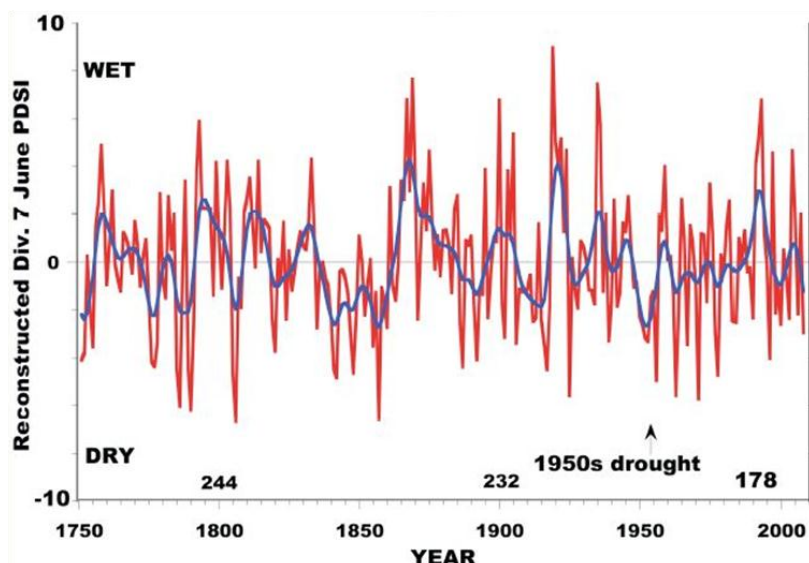


Figure 24. Tree ring history – 1750 to 2000 (June records only)

The Palmer index is most useful for semi-arid and dry sub-humid regions (this is the climatic area it was designed for) so any extrapolation of the PDSi into eastern or Coastal Texas (Sub-tropical Humid) is not recommended. The tree ring data can be used as a guideline for these areas, but extrapolating the Palmer index from recent monitoring data and suggesting this is the same as pre-historical times is not recommended.

4.2.6 Synthetic (Modeled) Drought Analysis

In order to further develop a drought analysis with a high stress level to the reservoir systems a drought analysis was developed utilizing data from the 1950's drought and analysis of the data outputs to make sure that the model output matched or exceeded this profile. A period of 20 years was modeled using Monte Carlo simulation against the 1950's and 2011 drought to determine rainfall scenarios that could then be used to aid with analysis of water availability.

Figure 25 shows an example output from a basic Monte Carlo analysis which was conducted to generate the random rainfall profile within the boundaries noted in the period of record. This synthetic analysis can be changed easily to simulate different conditions and timings for the rainfall patterns.

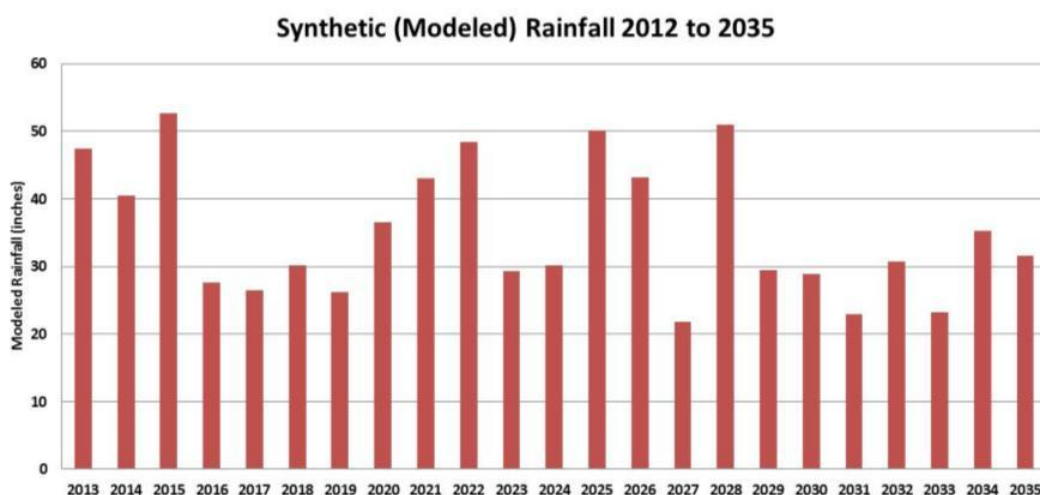


Figure 25. Synthetic Modeled Rainfall (2013 to 2035)

A goal of the B&V project was to analyze drought conditions at least as stressful as the drought of record (1950's) and preferably with additional stress, but still within possible bounds. The Monte Carlo analysis was conducted with the boundaries of the 110 year history of rainfall records available. Other data such as runoff, evapotranspiration etc. was not used in this simplified analysis. It was used in this situation for estimating a physical problem and providing sample datasets to work with compared with trial and error or specific period fitting.

4.3 SENIOR CALLS ON WATER RIGHTS BETWEEN 2011-2013

In 2011 through early 2013 the drought necessitated the need for some of the senior water rights holders to request a "senior call".

The following text is taken from

<http://www.senate.state.tx.us/75r/Senate/commit/c510/handouts12/0110-TCEQ.pdf>.

Reviewed 07/02/2012

The TCEQ's actions are guided by the priority doctrine, Texas Water Code Chapter 11. Domestic and livestock users have superior rights to any permitted surface water right holders. Between

permitted water right holders, those permit holders that got their authorization first (senior water rights) are entitled to receive their water before those water right holders that got their authorization later (junior water rights). If a water right holder is not getting water they are entitled to, they can call upon the TCEQ to take action to enforce the priority doctrine – a senior call.

The TCEQ received 15 senior calls in 2011, including calls on surface water in the Brazos, Guadalupe, Colorado, Sabine, and Neches River Basins. We are managing senior calls from users including the following types of users: municipal, industrial, irrigation, recreation, and domestic and livestock. All total, these senior calls have resulted in the suspension or curtailment of over twelve hundred (1,200) water right permits. Additionally, the TCEQ has stopped issuing temporary water right permits in basins affected by these calls. ***Suspended water rights do not include junior municipal or power generation uses because of concerns about public health and safety.***

TCEQ field staff enforced suspensions and curtailments through on-the-ground and aerial investigations. Field staff also conducted stream flow monitoring to help the agency make informed decisions regarding suspensions and management of senior calls.”

In late 2010, as drought conditions began to develop and intensify, the TCEQ initiated outreach activities.

- TCEQ’s Drought Hotline and Webpage were established to provide information to the public and regulated community about drought conditions and the agency’s on-going monitoring and response.
- TCEQ reconvened the Drought Team, originally formed during the 2009 drought. The Drought Team continues to meet weekly to monitor drought conditions and impacts and to consider and evaluate response. State agency partners from the Texas Department of Emergency Management and Texas Water Development Board regularly attend.
- In April 2011, the TCEQ communicated with state leadership, legislative officials, county judges, county extension agents, water right permit holders, and the media regarding drought conditions and the possibility of permit suspensions and/or curtailments. The TCEQ has provided additional notification to local legislative officials, judges, and county extension agents; water right holders; and the media as part of the response to each senior call.
- The agency has provided legislative briefings and a webcast concerning drought.
- The TCEQ has also provided targeted monitoring and outreach to public water systems.

4.3.1 Brazos River Authority

The Brazos River Authority also has surface water rights from which it contracts with various entities and businesses who wish to withdraw water from the Brazos, its lakes and tributaries. The Authority maintains a Drought Contingency Plan (DCP) that dictates how it manages and operates during times of drought. Under the DCP, required by TCEQ, each Authority system reservoir and the system as a whole have “trigger” points. If a lake level or the amount of water in the system falls below a trigger point, Authority officials may implement appropriate stages of the DCP.

These trigger points can prompt Authority officials to call for one of three alert stages, depending on the water level: Drought Watch, Drought Warning and Drought Emergency.

A Stage 1 Drought Watch is meant to raise public awareness about potential drought problems. Customers are recommended to practice voluntary water conservation measures. If the water level continues to fall, that can trigger declaration of a Stage 2 Drought Warning. This stage calls for efforts to reduce water use by 3 percent or more. Authority officials can ask water customers to begin voluntary or mandatory restrictions on water use, including on landscaping.

Finally, in the case of a severe drop in water levels, the Authority can move to Stage 3 Drought Emergency status, which has a goal of at least a 7 percent reduction in water use. In addition to the steps in the other drought stages, Authority officials can ask customers to begin mandatory water use restrictions for their customers, including prohibiting of hosing paved areas, use of ornamental fountains, washing cars, filling swimming pools and prohibiting planting new landscaping, among other limitations. These restrictions require BRA officials to notify TCEQ.

At the end of 2011, the entire Brazos River Authority system was at Stage 1 Drought Watch. Lakes Limestone, Georgetown and Proctor were at Stage 2 Drought Warning. Lake Somerville was listed as Stage 3 Drought Emergency.

4.3.2 Specific Water Rights Calls

As mentioned previously, 1,200 water rights were suspended due to the drought conditions in 2011. Even though many power generation water rights are relatively junior, the TCEQ decided that suspended water rights would not include junior municipal or power generation uses because of concerns about public health and safety. A brief description of the location and extent of water rights curtailment and management is outlined below:

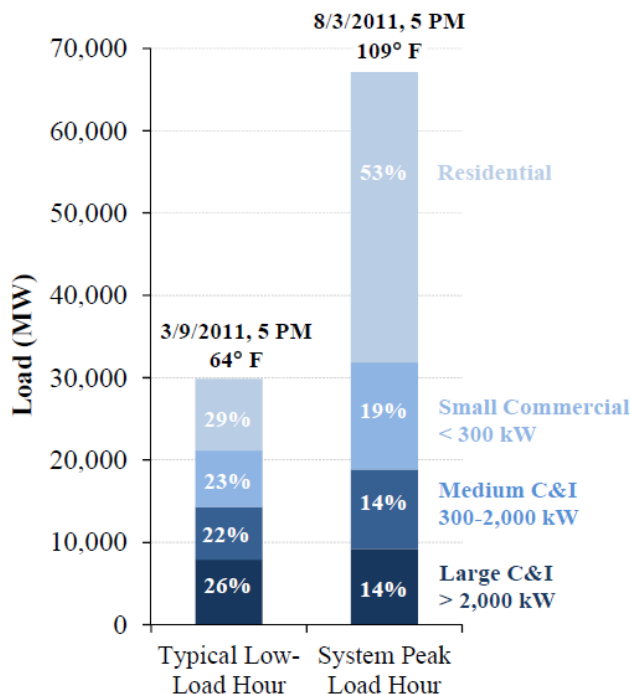
AREA	DISCUSSION
Neches River	Junior rights with priority dates back to August 13, 1913 were suspended in November 2011. They were reinstated on January 25th, 2012.
Brazos River	Junior rights with priority dates back to 1960 were suspended in the spring and summer of 2011. They were reinstated on January 27th, 2012. Junior Rights back to 1942 were suspended in November 2012 and rescinded on January 23rd, 2013.
Llano River	Junior rights with priority dates back to 1950 were suspended on July 5th 2011. They were reinstated on October 26th 2011
San Saba Watershed	Junior rights with priority dates back to 1900 were suspended in the summer of 2011. They were reinstated on February 2012.
Sabine (Little Sandy Creek)	Junior rights with priority dates back to 1903 were suspended in spring and summer 2011. They were reinstated in February 2012.
Rio Grande	Ongoing use of the Watermaster for rights below Amistad dam. Watermaster controls the allocations under a complex system that is designed to apportion water first for municipal, domestic and industrial uses.

4.4 ELECTRICITY DEMAND VARIATIONS DUE TO DROUGHT

While current generation will be affected by drought it is expected that demand will be affected also. Demand-side management (DSM) programs will become more prevalent, although a significant amount of work has already been completed in this area and the savings may be difficult

to achieve in areas where DSM has already been conducted. Figure 26 shows the typical load changes between a low load and peak load day. All the system sectors increase in usage, but the residential sector has by far the greatest change. This is also true in the water demand with residential irrigation being by far the largest contributor to increase in peak day demands. The peak electric load is not specifically driven by the increase of residential irrigation (it is mainly due to air-conditioning), but the connection to the residential systems is easy to correlate.

Peak and Off-Peak Load by Customer Segment



Source:

Based on ERCOT data, ERCOT (2012a).

Reported temperatures are from Dallas.

Customer class breakdown is for competitive choice areas.

Figure 26. Peak and off-peak load averages by customer segment (Source: Brattle Group 2012)

As expected rainfall does have an effect on the amount of electricity demanded during the summer months. Figure 27 shows the negative correlation between summer month rainfall and peak electricity demand. This can be used to help extrapolate future generation scenarios in drought years, although it is a basic analysis.

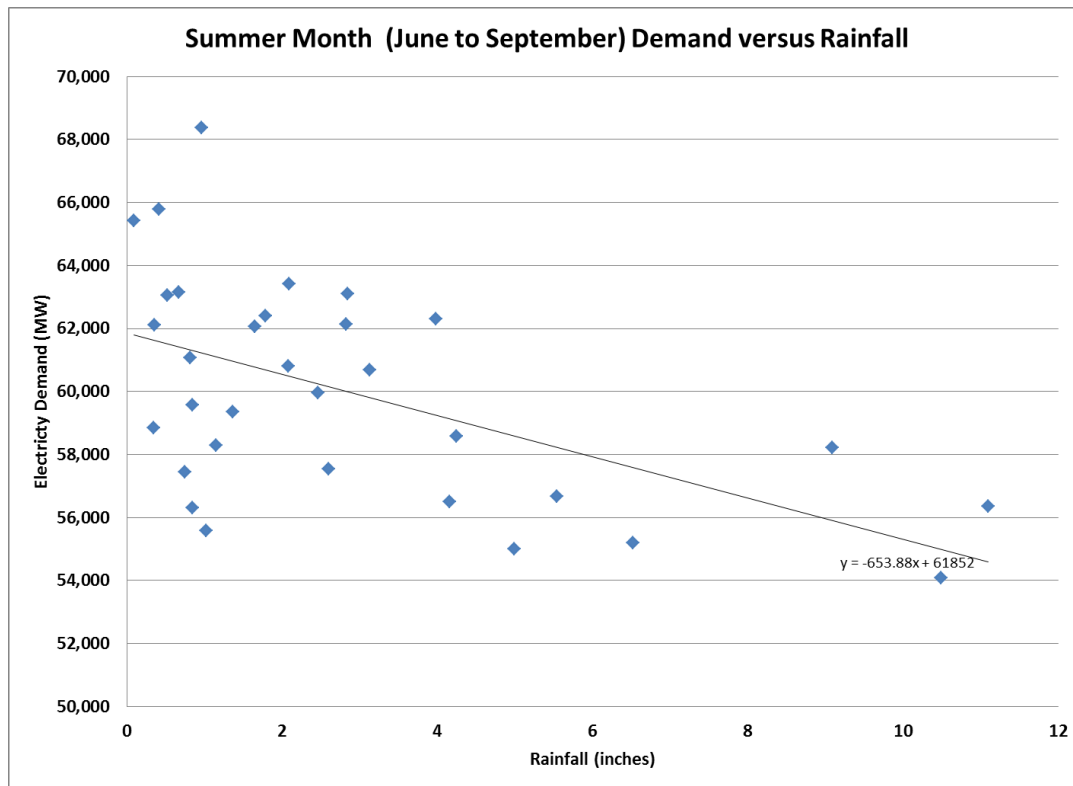


Figure 27. Demand (Peak MW) versus Rainfall (Average inches between 2004 and 2011)

4.4.1 Desalination

There are a number of industries that have a water component and use large amounts of energy. This is especially true of desalination. As demand for water supplies increase desalination will most likely become a water supply strategy within the ERCOT region. This will have effects both on the water supply availability, but also the need for power to operate these facilities. Through its regional water planning process, Texas has defined some potential for increasing desalination projects in six of the sixteen regions in the state. For more information on the regional water planning process see Section 3. In this analysis, six regions - A, C, F, L, M, and N have water supply strategies within the 2012 Water Plan. These include:

Region A -	Continue funding salinity control projects in Canadian and Red River basins
Region C -	Support research to advance desalination and reuse, and provide funding to small communities for desalination projects
Regions F and L -	Provide funds for desalination
Region M -	Continue funding brackish groundwater projects and seawater desalination demonstration projects

Region N - Encourage Texas Commission on Environmental Quality, TWDB, and Texas Parks and Wildlife Department to investigate environmental impacts of seawater desalination discharge and allow it where no damage will occur, and recommend changing regulations governing desalination brine to coincide with those governing petroleum brine.

The development of desalination technologies will need to be reviewed on a regular basis as it will affect the resource potential for water supply to power generators and will increase power demand significantly in areas where brackish water or seawater is available.

4.5 FUTURE WATER USE POTENTIAL FOR THERMAL POWER GENERATION

There are a number of factors which lead to the understanding that steam thermal generation is still viable in the ERCOT region;

- In the drought year of 2011 no thermal power generation facilities failed due to water supply availability.
- There are still areas in the east and south of Texas (close to and within the ERCOT region) which have un-appropriated water which is reportedly available and could be used for power generation purposes.
- There is still a misunderstanding between water withdrawal and water consumption for power generation facilities. Some reports suggest that power generation uses 49% of the state supply, whereas the actual consumption is closer to 3%.
- There are differences between the Sandia analysis of projected future water demand for power generation (steam electric) compared with the State Water Plan. This should be addressed and checked in the next State Water Planning cycle.
- Better understanding of resources and the regional availability for power generation can allow water availability to become a part of the operational planning of the network to reduce the possibility of drought impacts.
- Increased renewable generation will reduce the need for the current and future water supplies to be utilized for power generation. This will extend the useful life of these existing resources and reduce overall future demand for water.

4.6 BENEFITS OF SANDIA/ARGONNE WORK FOR ERCOT

The Sandia study has shown that there are significant variations in the availability and storage of water for the current power generation facilities in ERCOT throughout a drought period.

- An additional dataset is now available on the hydrologic characteristics, availability and costs of water for the surface water basins within Texas.
- A significant education process has been completed looking at the issues of withdrawal, use and availability of water.
- A temperature analysis has been conducted on most of the main reservoirs. While temperature variations are significant, they do not appear to be a major problem for large-scale outage within ERCOT.

Appendix V

ERCOT | WATER USE AND AVAILABILITY IN THE ERCOT REGION

- There is likely to be stress on power generation facilities within the central area of Texas (I 35 corridor) if drought conditions persist.
- New surface water resource availability appears currently possible in the east and coastal zones.
- Estimation of total water use was conducted. This can be used as a validation for the TWDB State Water Plan.

Appendix A—References and Links to Water Availability Documentation

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**Appendix W Recommendations for Enhancing ERCOT's
Long-Term Transmission Planning Process**

**Recommendations for Enhancing ERCOT's Long-Term Transmission Planning
Process**

The Brattle Group's Report to ERCOT

The Brattle Group

Recommendations for Enhancing ERCOT's Long-Term Transmission Planning Process

October 2013

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Prepared for



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Acknowledgements and Disclaimer

The authors acknowledge the valuable contributions of ERCOT staff members and stakeholders for helpful input, comments, and discussions. The opinions expressed in this article, as well as any errors or omissions, are solely those of the authors. The authors can be contacted at www.brattle.com.

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RECOMMENDATIONS FOR ENHANCING ERCOT'S LONG-TERM TRANSMISSION PLANNING PROCESS

EXECUTIVE SUMMARY

The Electric Reliability Council of Texas (ERCOT) engaged *The Brattle Group* (*Brattle*) to review ERCOT's process for screening economic transmission projects in its Long-Term Study (LTS) process, prepare recommendations on how to estimate more completely the economic value of transmission projects from a societal benefits perspective, and present before the ERCOT Long-Term Study Task Force (LTSTF) recommendations to improve the "Business Case" for economic transmission investments.

This effort focused specifically on ERCOT's 10-year Long-Term System Assessment (LTSA) methodology and the new 10- to 20-year scenario-based LTS process that ERCOT developed with support and funding from the U.S. Department of Energy (DOE). We examined those processes by interviewing stakeholders and ERCOT staff, carefully reviewing the available documentation, modeling tools, and evaluation criteria used by ERCOT, and obtaining input from ERCOT and stakeholders on our draft findings. Insights from our review and comparison to industry best practices have led us to recommend improvements to the LTS and LTSA processes. Our recommendations center on how ERCOT can more accurately and more completely assess the wide range of economic benefits that new transmission projects can provide to the system. Relatedly, we also assisted ERCOT staff in improving its analytical framework for comparing long-term benefits to project costs. As discussed further below, the specific recommended improvements include: (1) linking near- and long-term planning processes; (2) evaluating economic projects based on their net present value (NPV) or a comparison of levelized benefits and costs; (3) expanding the scope of benefits considered and quantified; (4) improving the use of scenarios and sensitivities; and (5) enhancing the process for identifying projects and the benefits/costs associated with specific projects.

With our recommended improvements, ERCOT will be able to identify economically-beneficial long-term transmission investments more effectively and to use that information in the evaluation of projects within its near-term (5 to 6 year) Regional Transmission Plan (RTP) process used to create ERCOT's actionable transmission plans.

A. SUMMARY OF FINDINGS

In our effort of evaluating ERCOT's long-term transmission planning process and identifying possible improvements, the *Brattle* team:

1. Reviewed ERCOT's long-term transmission planning scope and process;
2. Solicited ERCOT stakeholder input;
3. Reviewed ERCOT's modeling infrastructure and process;

4. Identified additional benefit metrics for more fully valuing transmission-related societal benefits and worked with ERCOT to develop case studies for evaluating the benefits;
5. Developed recommendations to: (a) improve ERCOT's transmission planning process for economic projects; (b) enhance its modeling infrastructure and practices; and (c) increase the scope of economic benefits through additional benefit metrics that should be considered in ERCOT's planning process; and
6. Presented findings and recommendations to ERCOT staff and ERCOT stakeholders.

Below is a brief summary of the findings from each of Tasks 1 through 4:

1. Review of ERCOT's Long-Term Planning Process

Prior to working with ERCOT staff and stakeholders, we reviewed ERCOT documentation of the DOE-sponsored LTS effort, its stakeholder processes, and prior Five-Year Transmission Plan and LTSA reports. Our document review was supplemented with interviews with ERCOT staff and stakeholders, as summarized below. We thereby identified the following topics where significant opportunities exist for ERCOT to improve the evaluation of economic transmission projects:

- ERCOT conducts two separate processes for its long term (10 to 20 year) and near-term (5 to 6 year) planning, making it difficult to compare project benefits across different timeframes. This hinders using results from the long-term planning process to evaluate projects (or project alternatives) in the actionable near-term planning process as intended.
- ERCOT currently compares estimated first-year production cost savings of an economic project with the project's first-year transmission revenue requirements (TRR), net of the TRRs of reliability projects that can be deferred or avoided by the economic project. This approach effectively imposes an impractically high threshold, because it ignores that benefits would typically increase over time with fuel cost inflation and load growth while the TRR of a project would decrease over time as the asset is depreciated.
- ERCOT currently compares project costs with only two limited sets of benefits in its economic project evaluation process: (1) a conservatively-low estimate of production cost savings based on simplified market simulations; and (2) the avoided TRR of deferred or replaced reliability projects. Transmission investments can provide a much wider range of benefits (or costs) that should be considered when evaluating economic projects. Other system operators have recently expanded their economic project evaluation processes to consider or evaluate up to a dozen distinct economic benefit metrics, most of which are applicable in ERCOT as well.

2. ERCOT Stakeholder Input

The *Brattle* team interviewed a wide range of ERCOT stakeholders to inform our understanding of the existing transmission planning process and to help assess what works well and where

improvements are needed. The stakeholders included utilities, transmission developers, generators, industrial consumers, landowners, market analysts, and the ERCOT Independent Market Monitor (IMM). Stakeholders provided extensive input on the long term planning process overall, on the changes currently underway in the process, and on other potential enhancements and concerns. Stakeholders also provided additional written comments in response to our findings and draft recommendations, which were presented on June 3, 2013.

Stakeholder input generally was focused on: (1) the purpose and the value of long term transmission planning in ERCOT; (2) the future scenarios and input assumptions developed for the long term study process; (3) the involvement of stakeholders in the long-term planning effort; (4) the scope of benefits and costs of transmission that should be considered in the planning process, and (5) specific feedback on our draft recommendations. For the first four of these topics, stakeholder comments included the following:

- *Use of Long-term Studies in Developing Transmission Expansion Plans:* Stakeholders generally appreciated the efforts ERCOT has made in planning the transmission system beyond the near term, and a subset of stakeholders felt that ERCOT's long-term studies are invaluable. Other stakeholders saw little value in long-term studies given the considerable uncertainties that exist beyond the 3- to 6-year time frame already considered in the RTP and former Five-Year Transmission Plan process—particularly given that the time needed to develop and construct new transmission in Texas is relatively short (*e.g.*, within the RTP timeframe). Further, some questioned the effectiveness of the existing process and expressed hope that, as ERCOT and stakeholders become more familiar with the new process, ERCOT would enhance its planning process over time. Some were particularly interested in developing a better understanding of the goals of the LTS process and how long-term planning results will be used to inform the near-term planning process that produces actionable projects. Many believed the LTS process should be used to identify more economically-efficient long-term solutions to transmission needs that would otherwise be resolved incrementally through reliability upgrades.
- *Future Scenario Development:* Many stakeholders showed particular interest in the future scenarios that were developed to inform the long-term transmission planning effort and appreciated that the process involved stakeholders. However, some believed that their opinions had not been fully considered in the scenario development process. Almost all of those who provided feedback expressed concern that some aspects of the chosen scenarios have been unrealistic. A subset thought the range of scenarios was too narrow and recommended that a more divergent set of scenarios, including extremes, be developed in order to evaluate the system near its breaking points and understand what system improvement could be valuable in those situations. Stakeholders consistently commented that the results of future long-term studies will only be accepted if a wide range of stakeholders consider the future scenarios used to be credible and that the

associated input assumptions are reasonable. There was general agreement that the current scenarios will need to be refined further and that increased stakeholder engagement will be needed to achieve acceptance of long-term planning results.

- *Stakeholder Involvement:* Most stakeholders expressed considerable interest in continued involvement in long term planning, especially in the development of scenarios and in reviewing results. Several stakeholders hoped that ERCOT would more deliberately incorporate input from transmission owners with specific local knowledge. Some suggested soliciting input on scenarios from a wider range of sources, including expertise from outside ERCOT and possibly outside the electric power industry (such as the oil and gas industry). In contrast, a few stakeholders expressed concerns about their ability to be involved in the process due to the highly technical nature of the discussions, the significant commitment of time and resources needed for participation, and the currently limited use of long-term study results.
- *The Scope of Transmission Benefits Considered:* Many stakeholders were receptive to considering additional categories of benefits in the transmission planning process. Some stakeholders expressed that transmission investments offer many benefits that should but have not yet been considered in ERCOT's planning process. In contrast, some are concerned that considering additional benefits will lead to an increase in unnecessary transmission build-out that could adversely affect electricity customers, land owners, and possibly other market participants. A few stakeholders also suggested broadening the scope of costs considered in the long-term study process, such as the costs of balancing the intermittent resources that are facilitated by new transmission lines and the cost associated with lost land value. Several stakeholders also suggested that ERCOT and the Public Utility Commission of Texas (PUCT) consider electricity customer benefits metrics in addition to relying solely on societal benefits.

3. Review of ERCOT Modeling Infrastructure and Process

We interviewed ERCOT modeling staff within the long-term, near-term, and resource-adequacy modeling groups and reviewed the documentation of the modeling processes they employ. The objective of the interviews was to identify opportunities for improving the modeling process and practices, including staff training needs (if any). While we acknowledge the concerns from stakeholders about certain assumptions that ERCOT has made in developing future scenarios in its 2012 LTS, our modeling interviews only focused on ERCOT's technical capabilities and methodologies, without examining potential improvements to the scenarios themselves nor the specific assumptions used in depicting each scenario.

Overall, we found that ERCOT's modeling processes are well designed and documented, and the modeling team members demonstrated strong expertise in transmission and economic modeling, with no identified need for additional market simulation training. While further improvements

are possible, several modeling techniques used by ERCOT are best-in-class, such as the methodology for adding future generation to the model where most economic (considering factors such as environmental siting challenges in load pockets, fuel supply, and locational market prices or LMPs) and making the appropriate technical adjustments to ensure that transmission constraints are modeled properly when making major additions of resources or transmission. Other best practices include the use of transmission reliability models alongside economic models and documentation of the process steps and results.

Our interviews with ERCOT's modeling staff and our review of their modeling processes revealed three areas that could be improved to support long-term planning more effectively.

- *Organizational and Modeling Team Structure:* ERCOT has two separate sub-groups, each with its own production cost model and its own set of inputs covering different timeframes. This creates duplication of work and risks inconsistencies in the modeling efforts. Having separate modeling teams also hinders the exchange of ideas and best practices between teams working on similar issues. We understand that ERCOT has already begun to address this concern by re-organizing the teams' structure to make it more efficient and consistent.
- *Designing Study Cases:* ERCOT could improve its modeling by defining selected scenarios in a way that is more credible to stakeholders. Other potential improvements include more fully representing generation outages (and other system stresses in the context of additional benefit metrics as discussed below) that regularly increase congestion. Study cases should also be defined carefully to distinguish between alternative and complementary transmission projects when evaluating portfolios of projects.
- *Validation of Results:* ERCOT has performed some model validation in the past when the modeling tools were initially developed. Such model validation and calibration efforts should be undertaken on a more regular basis to ensure that the market simulations can reasonably represent actual market conditions, market prices, and congestion patterns.

4. Benefit Metrics Considered

Establishing a robust business case for new economic transmission projects requires fully capturing the economic value that a transmission investment can provide to the system and properly accounting for the costs and benefits over the life of the project. Because the benefits of transmission investments are measured in large part as a reduction in system-wide costs, a failure to consider the full economic benefits of transmission investments is equivalent to not considering all costs and the potentially very-high-cost outcomes that market participants would be exposed to in the absence of these investments.

The two benefits currently considered by ERCOT in its planning efforts for economic transmission projects—modeled production cost savings and deferred or avoided reliability

upgrades—do not capture the full societal benefits and costs of transmission infrastructure investment. While estimating and using these two benefit metrics represents a good starting point, they reflect a narrow subset of the wider range of benefits that are increasingly considered in the industry today, including by other system operators in Texas and surrounding regions.

To allow ERCOT to benefit from the quickly evolving industry experience, we document the types of transmission-related economic benefits quantified and considered by other system operators in Texas, neighboring regions, and other parts of the U.S. Based on a review of this industry experience and our own, we provided ERCOT with a comprehensive “checklist” of potential economic benefits of transmission infrastructure investments. This checklist, summarized in Table ES-1, served as the starting point to discuss the additional economic benefit metrics that ERCOT could develop and incorporate in its transmission planning efforts over time. As noted during our presentation to stakeholders and ERCOT staff, this checklist of potential benefits does not necessarily mean that every category of benefit would increase the value of all transmission projects; some of these benefit categories may yield negative values for certain projects, thus representing societal costs.

We reviewed the list of potential metrics with ERCOT staff, assessed their relevance to ERCOT, and identified the most promising metrics that could be added by ERCOT immediately to improve its current modeling practices. We also identified promising benefit metrics that will require the development of additional modeling tools and analytical capabilities. In parallel, ERCOT has begun to develop case studies that apply some of the identified approaches and metrics to gain familiarity with the necessary modeling and analytical efforts necessary to build the “tool kits” that can be used to evaluate proposed economic transmission projects in the future. The recommendations for near-term implementation are summarized in the right column of Table ES-1 and are discussed further below. Additional recommendations concerning benefit metrics that ERCOT should consider developing in the longer-term are discussed in the main body of the report.

Table ES-1
Checklist of Benefits and Recommended Metrics for Implementation

Checklist of Potential Economic Benefits of Transmission		Already Used	Recommended for Near-Term Implementation
1. Traditional Production Cost Savings <i>(as currently considered by ERCOT)</i>		✓	Improve
1a – 1i. Additional Production Cost Savings			
a.	Impact of generation unit outages and designations for ancillary services		✓
b.	Reduced transmission energy losses		✓
c.	Reduced congestion due to transmission outages		✓ (multiplier)
d.	Mitigation of extreme events and system contingencies		
e.	Mitigation of weather and load uncertainty		✓ (multiplier)
f.	Reduced costs due to imperfect foresight of real-time conditions		
g.	Reduced cost of cycling power plants		✓
h.	Reduced amounts and costs of ancillary services		
i.	Mitigation of RMR conditions		
2. Reliability and Resource Adequacy Benefits			
a.	Avoided or deferred reliability projects <i>(as already considered by ERCOT)</i>	✓	Improve
b.	Reduced loss of load probability, or:		
c.	Reduced planning reserve margin		
3. Generation Investment Cost Savings			
a.	Generation investment cost benefits from reduced peak energy losses		✓
b.	Deferred generation capacity investments		Case by case
c.	Access to lower-cost generation		Case by case
4. Market Benefits			
a.	Increased competition		
b.	Increased market liquidity		
5. Environmental Benefits			
a.	Reduced emissions of air pollutants		✓
b.	Improved utilization of transmission corridors		Qualitative
6. Public Policy Benefits			
a.	Reduced cost of meeting public policy goals		
7. Employment and Economic Stimulus Benefits			
a.	Increased employment and economic activity; increased tax revenue		
8. Other Project-Specific Benefits			
such as:	Storm hardening, load serving capability, synergies with future transmission projects, fuel diversity and resource planning flexibility, wheeling revenues, transmission rights and customer congestion-hedging value, HVDC operational benefits		Case-by-case

B. SUMMARY OF RECOMMENDATIONS

Based on our review of ERCOT's long-term transmission planning process and the findings summarized above, we developed the following recommendations for further consideration by ERCOT and its stakeholders. The initial draft of these recommendations, as summarized in Table ES-2, was presented to stakeholders in a public meeting on June 3, 2013.

Table ES-2

Recommendations for Enhancing ERCOT's Transmission Planning Process	
1:	Link Near- and Long-term Planning Processes
2:	Evaluate Economic Projects based on their NPV or a Comparison of Levelized Benefits and Costs
3:	Expand Benefits (and Costs) Considered and Quantified
4:	Identify Key Uncertainties and Improve Development and Use of Scenarios and Sensitivities
5:	Enhance Economic Project and Benefits/Costs Identification Process

We received eleven sets of stakeholder comments in response to the draft recommendations presented at the stakeholder meeting. The comments covered a diverse set of opinions, ranging from broad support for the presented recommendations, to the recommendation that new transmission projects should only be planned to maintain reliability and lower costs to consumers (as opposed to considering societal benefits), to concerns about the value or process of scenario-based planning, and the position that benefits more than a few years in the future are highly speculative and should not be considered. In general, however, the majority of stakeholders support: (a) linking the long-term planning effort to the near-term RTP process for the evaluation of economic projects; (b) adding at least a subset of the potential additional benefit metrics (after considering additional stakeholder input); and (c) utilizing NPV concepts in comparing costs and benefits (although differences of opinions exist about the discount rates that should be applied to long-term benefits and costs).

Our finalized recommendations are summarized below:

1. Link Near-Term and Long-Term Planning Processes

We recommend that ERCOT more systematically link its long-term (LTSA) transmission planning processes to the near-term (RTP) planning process. Such a linkage would increase the consistency in modeling assumptions and results across the two planning horizons, avoid

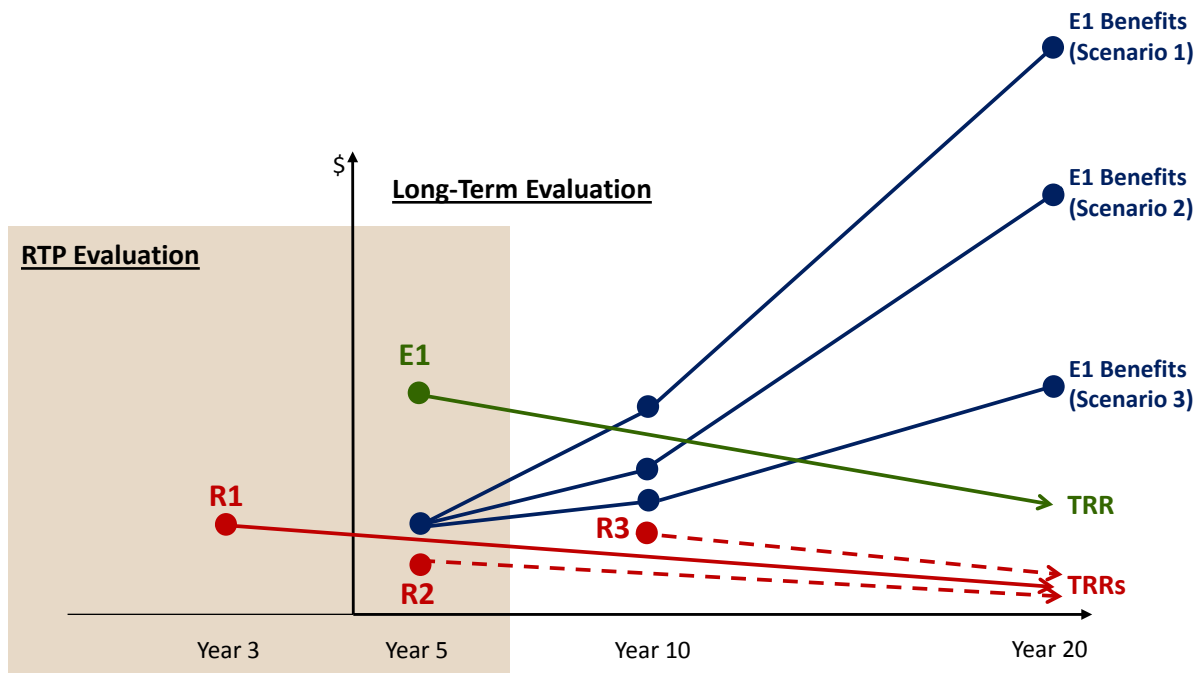
overlapping modeling efforts, and allow the effective use of results from long-term studies to inform near-term planning efforts. Accordingly, we also recommend integrating ERCOT's near- and long-term modeling teams and using a single economic model with consistent input assumptions for both the near-term and long-term analyses. Such integration would help improve the quality, consistency, and efficiency of the workflow and enable a more integrated transmission planning process going forward.

Specifically, we recommend that ERCOT use the results of its long-term studies in the identification and evaluation of economic transmission projects within its RTP process. Transmission needs would continue to be determined and approved primarily through the RTP process, with most projects considered to be built over the ensuing 5 to 6 years of the RTP time frame. However, the monetary value of the benefits and costs of economic projects that could be developed within that 5 to 6 year time frame would be estimated based on results from both the near-term and long-term analyses. Utilizing information about the benefits and costs of an economic project over a significant portion of its useful life would help determine the actual economic value of a project, which in turn would help assess more accurately the tradeoffs between incremental reliability upgrades and economic project alternatives.

Figure ES-1 illustrates our recommendation of linking the near- and the long-term planning processes. This hypothetical example compares annual dollar values (y-axis) over time (x-axis). The RTP process (over the first 5-6 years) is represented by the shaded block on the left. In this illustration, the RTP process identified two reliability upgrades, "R1" and "R2," which would be needed in years 3 and 5, respectively. The red dots and lines corresponding to R1 and R2 represent the regulated annual costs of the reliability projects (in terms of annual transmission revenue requirements or "TRRs"). These annual costs decline as the assets are depreciated over their useful life (typically over 40 to 50 years).

Figure ES-1 also shows an economic transmission project, "E1," proposed to be installed in year 5. In this example, if E1 were built, R2 would not be needed. The green dot and line that correspond to E1 illustrate that the annual costs of E1 are significantly higher than the annual costs of R2 (as illustrated by the red dot and dashed line). However, in addition to avoiding the construction of R2, the development of E1 would also offer incremental production cost savings (above those associated with R2) as indicated by the three trajectories of blue dots and lines. The three blue lines depict the project's total annual savings under three alternative future scenarios.

Figure ES-1
Linking Near-Term and Long-Term Evaluation of Economic Projects



Under ERCOT’s current evaluation process, the first-year revenue requirements of Project E1, net of the avoided first-year costs of R2 would be compared to the annual production cost savings achieved by E1 in its first year. With such a comparison and threshold, as illustrated, Project E1 would be rejected because its first-year costs exceed the sum of avoided R2 costs and production cost savings in that year. This approach ignores the potentially very different future balance of costs and benefits that would make Project E1 a better long-term choice even in year 5 of the RTP evaluation.

The three blue lines show that, under the three alternative future scenarios, the total long-term savings offered by E1 in its first operating year (i.e., year 5) would grow at different rates over time, consistent with the typical trends caused by the combined effects of load growth and increasing fuel prices. It is also possible that the production cost savings would decrease over time, for example, if load and fuel prices decreased or if future reliability projects offered overlapping production cost savings as E1. The three different trajectories of annual benefits depend on the assumptions used in depicting the alternative future scenarios.

The hypothetical example shown in Figure ES-1 reflects the assumption that if E1 were built in year 5, it would also avoid another reliability upgrade, “R3,” in year 10 (which would likely be identified in the subsequent RTP evaluations, in absence of E1). Thus, an evaluation of whether the economic project E1 should be pursued requires estimates of avoided reliability project costs that would be offered by E1 over time.

In Figure ES-1 we only show the hypothetical annual production cost savings of E1 and the avoided annual cost of reliability upgrades R2 and R3. Nevertheless, as illustrated, while project E1 could not be justified by comparing first-year costs with its limited first-year benefits, the total cumulative *value* of the economic project's benefits, even if annual benefits are increasingly discounted over time, would significantly exceed total project costs under most if not all future scenarios.

As the illustration in Figure ES-1 shows, the economic project E1 would still undergo evaluation and approval through the RTP process for completion in year 5, but the comparison of its benefits and costs would be informed by the results from the long-term assessment that reaches out 20 years. The scenario-based long-term assessment would also indicate the robustness of the economic project's value under the alternative future scenarios, which can also be considered in the RTP process.

2. Evaluate Economic Projects based on their Net Present Value (NPV) or a Comparison of Levelized Benefits and Costs

The economic benefits of transmission projects and their alternatives accrue over the entire life of the asset. We consequently recommend that the long-term value of costs and benefits be considered in the evaluation of potential economic transmission projects. While decisions about necessary reliability-driven transmission projects can be made based on conditions in the year when the identified reliability need first occurs, decisions about economically-justified projects require the assessment of economic value, which is defined by the benefits and costs that accrue over the useful life of the investment.

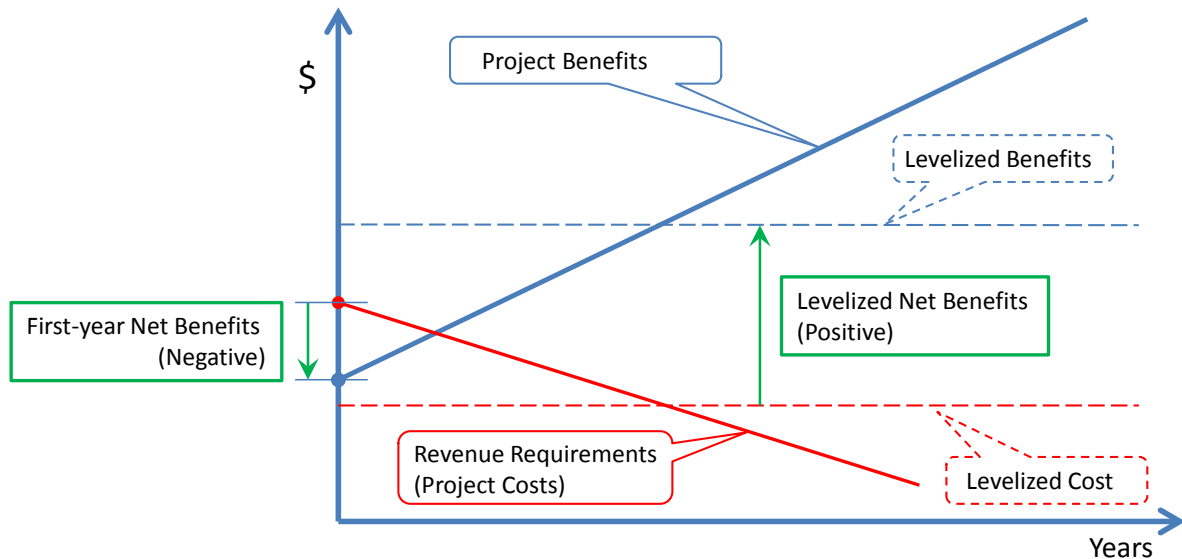
The current ERCOT practice used to evaluate economic projects typically performs production simulations only for the first year of the proposed project. ERCOT then compares the first-year production cost savings against $1/6^{\text{th}}$ of the project's construction costs, net of $1/6^{\text{th}}$ of any avoided reliability project costs in that year. Taking $1/6^{\text{th}}$ of a project's construction cost is approximately equal to the project's regulated cost of service (*i.e.*, its regulated transmission revenue requirement or TRR) in the first year. This approach carries a high risk of rejecting potentially beneficial economic projects for three main reasons:

- a. Production cost savings and other benefits tend to grow over time with increasing load and fuel prices. As a result (although this is not always the case), the production cost savings for the first year of a project are generally lower than the "levelized" annual benefit that reflects the project's average savings over time. Figure ES-2 below illustrates how the levelized annual value of long-term benefits can be much larger than the benefits in the first year of a new project. As illustrated, it can easily be the case that first-year net benefits are less than first-year costs, even though levelized net benefits significantly exceed both first-year costs and levelized costs.
- b. Transmission revenue requirements decline over time as the assets are depreciated. The first-year TRR of a project, estimated as $1/6^{\text{th}}$ of its construction cost, is approximately 30% higher than the levelized annual value of its TRR over time. Thus, if benefits need

to exceed the $1/6^{\text{th}}$ of the project's construction cost, then the levelized benefits need to be approximately 30% greater than the project's levelized revenue requirements.

- c. The economic project may offer benefits beyond production cost savings and avoided reliability project costs that should be considered as well. We discuss this point in Recommendation No. 3 below.

Figure ES-2
Comparing First-Year and Levelized Project Costs and Benefits



For these reasons, we recommend that the costs and benefits associated with proposed transmission projects be compared based on their present values or levelized values. The present value approach compares the present value of a project's long-term benefits to the present value of a project's costs. The present values of benefits and costs are estimated as the sum of annual benefits and annual costs, both increasingly discounted over time to reflect the fact that a dollar spent or saved 10 or 20 years from now is significantly less valuable than a dollar saved or spent today. To estimate annual benefits over time, the annual values for some years can be interpolated based on specific estimates for a few future years, such as year 1, year 5, and year 10 (or year 20) and extrapolated further into the future based on a conservative assumption of how benefits would grow or remain constant over time, recognizing that the value of transmission investments rarely declines over the long term.

The time frame over which the present values of benefits and costs are calculated is often 20 or 40 years in other planning regions, although some system operators use time horizons as short as 10 years while others estimate values over the full 50 years of a project's assumed life. We recommend that ERCOT consider estimating benefits and costs over a 20 to 40 year period, consistent with the time horizon used in neighboring regions.

Regarding discount rates applied to project costs and benefits, we recommend using the weighted average cost of capital of the transmission owners, although some planning regions (such as the Midcontinent ISO, MISO) also use a lower “societal” discount rate for both costs and benefits. We recommend against applying a higher discount rate to transmission benefits than the discount rate that is applied to annual transmission costs. Rather, we recommend a PUCT-approved weighted average cost of capital for transmission owners to discount both future benefits and costs. This rate appropriately reflects the risks of transmission investments. Using a higher rate would understate the potentially high costs imposed on market participants in the absence of the contemplated transmission investment. Any higher perceived uncertainties associated with estimated benefits are already addressed through benefit-cost thresholds that exceed 1.0 (such as 1.25 in most other regions) and the recognition that many transmission-related benefits often are not quantified.

As an alternative to comparing the present values of benefits and costs, it is equally suitable to compare the benefits and costs using levelized annual values. This is because the “levelized” costs and benefits are the equalized annual values that yield the same present values as the estimated time-varying amounts. Such NPV-based or levelized benefit and cost comparisons are used by virtually all other system operators and we recommend ERCOT adopt a similar methodology.

ERCOT’s approach of comparing the benefits of a project with $1/6^{\text{th}}$ of the project’s construction costs (as an estimate of the project’s first year of revenue requirements) is consistent with recent orders from the PUCT. However, as shown in Figure ES-2, the first-year TRR of a transmission project is at its highest relative to the rest of the useful life of the project. Under typical ratemaking treatment of transmission costs, a project’s first year TRR is approximately 30% higher than the levelized value of these TRRs that yields the same present value over the project life as the actual declining profile of TRRs. Thus, comparing levelized benefits to $1/6^{\text{th}}$ of the project’s construction costs is equivalent to a requirement that the benefit-cost ratio of a project exceeds 1.3 from a present value perspective. We do not advise modifying this criterion at this point, but recommend that ERCOT also calculate a project’s benefit-cost ratio based on levelized benefits and levelized costs to recognize the extent to which this approach requires that the value of estimated benefits exceed estimated costs.

3. Expand The Range of Benefits (and Costs) Considered and Estimated in the Evaluation of Economic Transmission Projects

We recommend that ERCOT more fully consider and estimate the economic value of transmission investments. This requires expanding the economic benefits and costs of transmission investments considered in ERCOT’s planning efforts. The wider range of benefits and costs will more accurately reflect the value that new transmission can provide to the system.

As it would be difficult for ERCOT to evaluate the complete set of benefit metrics shown in Table ES-1 above for each proposed project, we recommend that ERCOT implement only a

subset of these benefits and benefit metrics in the near term. As we explain in more detail in the full body of the report, we recommend that ERCOT improve its treatment of production cost savings and the benefits from deferring or avoiding reliability projects. We also recommend that ERCOT estimate seven additional benefit metrics in its economic evaluation process, two of which would be applied as a typical multiplier to standard estimates of production cost savings. These additional metrics could be applied to each major economic project or portfolios of projects found most promising based on production cost savings and avoided or deferred reliability projects.

The scope of production cost savings, as currently estimated by ERCOT, should be expanded to include estimates of savings beyond a project's first year. For example, a reasonable approach would be to estimate savings for years 1, 5, and 10 of a project and then use these annual estimates to develop estimates for the long-term present value of a project's production cost benefits. The estimated benefit of an economic project's ability to defer or avoid reliability projects should similarly be expanded beyond the project's first year to reflect the present value of reduced or deferred future reliability investments.

In terms of additional benefits and costs to be estimated, we recommend that ERCOT: (1) modify its long-term market simulations to capture the impact of forced generation unit outages and ancillary service unit designations; (2) more fully estimate the reduced (or possibly increased) production costs due to project-related changes in transmission losses; (3) study the typical impact of transmission outages on project-related production cost savings to develop a multiplier that could be applied to standard estimates of production cost savings going forward; (4) similarly develop a multiplier to capture the disproportionately higher project-related benefits during weather-related spikes in peak loads; (5) modify simulations to more completely capture cost reductions (or increases) due to a project's impact on the operational cycling of power plants; (6) estimate any decreases (or increases) in installed capacity requirements due to changes in on-peak transmission losses; and (7) more fully consider emission-related costs (including for long-term risk mitigation benefits).

We further recommend that, at this point, the other benefits in Table ES-1 be considered, discussed, and analyzed only on a case-by-case basis for projects that are anticipated to offer significant value in terms of the individual benefit types. For example, an evaluation of generation cost savings may be undertaken in the future in the context of a transmission project that allows for either the deferral of generation investments (*e.g.*, by allowing plants in neighboring regions with surplus capacity to "switch" into ERCOT) or the development of new generating plants to be shifted from high-cost locations (*e.g.*, areas that have higher land costs or would require greater investment in emission controls) to lower-cost locations. Similarly, project-specific benefits should be evaluated on a case-by-case basis as future projects offer unique benefits, such as opportunities for improved utilization of transmission rights-of-way or the creation of low-cost options for possible future transmission projects.

To implement the recommended additional benefit metrics in the transmission planning process, it will be necessary to develop and refine proposed approaches through the Regional Planning Group (RPG) stakeholder process. We also anticipate that stakeholder workshops be used to fully explain the details of each proposed benefit metric and document with case studies how ERCOT has quantified its value. As ERCOT's experience with project-specific additional benefits metrics increases over time, these metrics should then be added to the set of metrics that is routinely considered.

4. Improve Use of Scenarios and Sensitivities

Recognizing the uncertainties about the future, particularly from a long-term perspective, we recommend that ERCOT improve its use of scenarios and sensitivities considered in the long-term planning process. Stakeholder feedback provided insight into the scenario-development process that had been undertaken in the last two years to create plausible and reasonable scenarios about future market conditions. Having made some significant progress, there are opportunities to meaningfully improve both the scenario development process and the usage of scenarios and sensitivities in the evaluation of project benefits and costs.

Further refining the stakeholder process is a key part of improving scenario development. It is clear that stakeholders will accept the results of long-term studies more readily if they understand the assumptions embodied in the scenarios and believe they reflect a reasonably complete range of plausible future market conditions. Building on the experience with ERCOT's recent scenario development effort, the next iteration of this process can be defined more clearly from the onset. ERCOT can specify more concisely how scenarios will be used in the long-term planning effort and how long-term planning results will be used in the RTP process. It is important for ERCOT to reiterate its invitation to all potentially interested parties to participate in this process and make clear that stakeholder buy-in for the scenario assumptions and planning effort will lead to "results that matter."

To achieve these goals, we recommend that the scenario development process be a facilitated stakeholder-driven process that includes representatives from each sector within the electric power industry as well as experts from outside of ERCOT and the power industry (such as from the oil and gas sectors) to share their views on the future of the state's economy and energy industry, including their perspectives regarding electricity usages and potential growth for the industry. The scenarios should reflect a wide range of plausible future outcomes in terms of ERCOT-wide and localized load growth, generation mix and locations, and fuel prices. The range in long-term values of economic transmission projects under the various scenarios should be used to assess the robustness of a project's cost effectiveness.

We recommend that short-term uncertainties that exist within any one of the scenarios—such as weather-related load fluctuations, hydrological uncertainties, short- and medium-term fuel price volatility, and generation and transmission contingencies—should not drive scenario definitions. Rather, such uncertainties should be simulated probabilistically or through sensitivity analyses

for each of the chosen scenarios to capture the full range of societal value of transmission investments.

5. Enhance Economic Project and Benefits/Costs Identification Process

Finally, we recommend that ERCOT refine its process for identifying candidate economic transmission projects and the range of benefits specific to each project. We recommend that ERCOT consider establishing a structured process that allows market participants to propose candidate economic projects. Under this process, market participants would also need to identify the proposed projects' likely benefits and costs (consistent with the "checklist" provided in Table ES-1) and discuss (at least qualitatively) the possible magnitude of and why the project is expected to offer the identified benefits. It will be important that the initial list of benefits not be limited to ERCOT's analytical capabilities for estimating the magnitude of the benefits, but provide a comprehensive list of expected benefits regardless of modeling capabilities. Even if the value of some benefits is not easily estimated with existing tools, they should still be considered and at least be discussed qualitatively. Once proposed projects and their likely benefits have been specified, ERCOT can prioritize the proposed projects with stakeholder input and undertake benefit-cost analysis based on the available analytical capabilities to determine whether a proposed project meets its economic planning requirements.

I. INTRODUCTION AND BACKGROUND

The Electric Reliability Council of Texas (ERCOT) asked *The Brattle Group* (*Brattle*) to review the ERCOT process for screening economic transmission projects in the Long-Term Study (LTS) horizon, prepare recommendations on how to more completely estimate the economic value of transmission expansion from a societal perspective, and present to the ERCOT Long-Term Study Task Force (LTSTF) recommendations on how to improve its “Business Case” for transmission investment.

This effort specifically focused on reviewing ERCOT’s existing 10-year Long-Term System Assessment (LTSA) methodology and its new scenario-based planning process that focuses on a 10- to 20-year time horizon and has been developed with the support of funding from the U.S. Department of Energy (DOE).

A. BACKGROUND ON ERCOT TRANSMISSION PLANNING

Transmission planning is a highly technical and relatively complex process that must consider a range of future uncertainties. ERCOT’s existing planning process is undertaken over several time horizons to identify and approve new transmission investments required in the near-term to maintain system reliability and efficiency, and to evaluate upgrades that may be required in the long-term under different future states of the world. As part of its planning efforts, ERCOT produces planning reports focused on generation resource adequacy (Seasonal Assessment of Resource Adequacy and Capacity, Demand and Reserves Report), near-term transmission constraints and upgrades (Constraints and Needs Report and the Regional Transmission Plan), and long-term system resource needs analysis (Long-Term System Assessment).

Two stakeholder groups, the Regional Planning Group (RPG) and the LTSTF, support these efforts. As stated in its charter, “the RPG is a non-voting, consensus-based organization focused on identifying needs, identifying potential solutions, communicating varying viewpoints and reviewing analyses related to the transmission system in the planning horizon.”¹ In contrast, the LTSTF provides the primary forum for discussion between representatives of appropriate state agencies, non-governmental organizations (NGOs), policy-makers, other planning stakeholders, and ERCOT regarding issues affecting long-range power system planning in the ERCOT Region and specific inputs, results, and feedback on long-term planning studies.²

Specific transmission projects are developed by ERCOT through its Regional Transmission Plan (RTP) process, in coordination with the RPG and Transmission Service Providers (TSPs). The

¹ ERCOT, 2012c.

² See <http://www.ercot.com/committees/other/lts/>. The LTSTF is supported by the Scenario Development Working Group (SDWG), which provides the forum for discussions between these stakeholders and ERCOT regarding the development of scenarios to be studied as part of the Long-Term Study.

RTP—formerly called the Five-Year Transmission Plan (FYP)—has recently been expanded from a five-year horizon to assess transmission needs over a six-year horizon. Each year, the RTP is developed by ERCOT to address region-wide reliability and economic transmission needs.³ Planned improvements to the ERCOT transmission system that will be reviewed for the RTP include:

- Projects previously approved by the ERCOT Board
- Projects previously reviewed by the RPG
- New projects that will be refined at the appropriate time by TSPs in order to complete RPG review
- Local projects currently planned by TSPs

For a new transmission project to be built in ERCOT, it must gain approval from the RPG through its tiered review approach that requires different levels of review depending on the size and cost of the project.⁴

The objective of the existing LTSA is to assess the potential needs of the ERCOT system ten years into the future. The LTSA is not used to recommend the construction of specific transmission projects. Instead, ERCOT uses the LTSA to evaluate possible system upgrades that may be required over the 10-year horizon. This long-term outlook is used to inform the 6-year planning effort undertaken through the RTP and RPG processes, and possibly to identify more options than the near-term upgrades specifically considered in the RTP context.

B. MOTIVATION FOR ENHANCEMENT OF LONG TERM PLANNING PROCESS

The industry has increased its focus on evaluating the economic benefits of transmission investments in the transmission planning process. The evolving recognition that transmission investments can provide a wide range of economic benefits has often provided strong support for making certain transmission investments that serve more than meeting reliability requirements. Outside of ERCOT, the evaluation of economic benefits also in part has been motivated by regulatory requirements that the allocation of transmission costs be roughly commensurate with the benefits received from the investments.

ERCOT has recently increased its long-term transmission planning capabilities through a grant received from the U.S. Department of Energy. The purpose of the grant is to provide relevant and timely information on long-term system needs to inform near-term planning and policy decisions, to expand ERCOT long-term planning capabilities by developing new tools and processes to be used in future studies, and to facilitate enhanced input from stakeholders in the

³ ERCOT, 2013a.

⁴ For example, only transmission projects with capital costs greater than \$15 million require a review by the ERCOT RPG.

long-term planning process.⁵ At the time that our engagement started, ERCOT had already completed several objectives set out in the DOE grant through the LTS effort. Specifically, ERCOT had already:

- Developed a repeatable process to identify long-term reliability and economic efficiency system needs;
- Defined and studied one full spectrum of 10- to 20-year scenarios and resource portfolios;
- Used the long-term results to inform shorter-term studies with “least regrets” solutions across the scenarios as assumptions become more certain; and
- Implemented a tool and study framework for identifying ancillary service needs for increasing quantities of non-traditional resources.

In addition, ERCOT aimed to use the DOE grant to complete an additional analysis and stakeholder review to develop a process for assessing adequate and cost-effective transmission upgrades over the long term that will improve all transmission planning studies conducted by ERCOT.⁶

C. OBJECTIVES AND APPROACH OF BRATTLE ENGAGEMENT

Our engagement to expand the economic evaluation capabilities of ERCOT’s long-term planning efforts, funded by the DOE grant as well, comes at the end of the LTSA project. Our review consequently includes an assessment of many of the process improvements that have already been implemented by ERCOT under the grant. The specific focus of our work was to assess the evaluation criteria for economic transmission expansion used in the ERCOT long-term planning process and to recommend enhancements to the planning process and system modeling that will allow for a broader range of benefit metrics to be considered from a societal perspective. A better understanding of the benefits and costs of economic transmission projects is meant to allow ERCOT to improve its “business case” for new economic transmission projects. A clear understanding of and appreciation for these benefits and costs over the long term and a range of different future scenarios will also help to increase the robustness of transmission plans.

The aim of creating a “business case” for new economic transmission projects reflects the fact that, historically, transmission projects have been evaluated and designed based on engineering criteria with the primary goal of maintaining system reliability. However, transmission investments provide a wide range of societal value beyond system reliability. Currently, the lack of a process that can identify and analyze a broad range of those benefits in the context of long-term planning limits the evaluations of transmission projects to only capturing a portion of the

⁵ ERCOT, 2011b, p. 1.

⁶ *Id.*, p. 21.

overall economic benefits and thereby inadequately considering the long-term value that beneficial transmission investments offer. Transmission planning is a complex effort defined both by high-level objectives and detailed analytical efforts. For these reasons, identifying potential process improvements requires a detailed evaluation of the long-term transmission planning process at several levels, in terms of both improving the process and broadening its scope. As summarized in Table 1, we have focused our review and recommendation to address each of the following four dimensions of transmission planning: (1) effective high-level study objectives; (2) repeatable execution of specific process steps; (3) reliable application of analytical tools; and (4) understandable and consistent use of analytical results.

Table 1
Approach to Long Term Study Review

	Assess and Improve the Process for the Existing Planning Scope	Broaden the Scope to More Effectively Identify Projects with Net Benefits
1. Study Plan (objectives and high-level concepts)	<ul style="list-style-type: none"> - Identify limitations of scope of benefits quantified and project evaluation criteria 	<ul style="list-style-type: none"> - Add benefit categories and metrics - Describe how study scope could be improved - Suggest enhancements to project evaluation criteria
2. Process Steps	<ul style="list-style-type: none"> - Identify opportunities for improving and streamlining the process - Will be informed by an assessment of effort and value, and comparison to processes we've done/seen - Clarify process/stakeholder input for identifying promising projects and their likely benefit categories 	<ul style="list-style-type: none"> - Identify aspects that can be readily added to existing modeling system - How to evaluate benefits that can not be captured in existing modeling system - For additions that may be a more major effort: <ul style="list-style-type: none"> - Develop potential process modifications - Identify ways to streamline (e.g., apply selectively or to a portfolio; develop generic benefit multipliers)
3. Modeling Tools, Execution, and Quality Control Practices	<ul style="list-style-type: none"> - Identify specific improvement opportunities for: <ul style="list-style-type: none"> - model calibration - quality control (diagnostics and review) - data and case management - automation of repeated processes - documentation of modeling steps - staff training 	<ul style="list-style-type: none"> - What are best practices and training needs for successfully executing new steps/tools?
4. What to do with the Results		<ul style="list-style-type: none"> - Identify ways to integrate LT planning better with actionable near-term planning (e.g., by merging models and including LT NPV in near-term study)

In this effort of evaluating ERCOT's existing long-term transmission planning process and identifying possible improvements to scope, process, modeling, and utilization of results, our team completed the following tasks:

1. Reviewed ERCOT's long-term transmission planning scope and process
2. Solicited ERCOT stakeholder input
3. Reviewed ERCOT's modeling infrastructure and process

4. Identified additional benefit metrics for valuing additional (non-conventional) transmission-related societal benefits and worked with ERCOT to develop case studies for evaluating the benefits
5. Developed recommendations to: (a) improve ERCOT's transmission planning process for economic projects; (b) enhance its modeling infrastructure and practices; and (c) increase the scope of economic benefits through additional benefit metrics that should be considered in ERCOT's planning process
6. Presented findings and recommendations to ERCOT staff and ERCOT stakeholders.

The remainder of this report documents our efforts along each of these tasks. Section II provides a more detailed discussion of ERCOT's Long-Term Transmission Planning process. Section III summarizes stakeholder comments regarding the long-term planning process and presents a subset of our recommendations based on that stakeholder feedback. Section IV summarizes our review of and recommendations concerning ERCOT's modeling infrastructure and practices. Section V explores additional benefit metrics for valuing additional (non-conventional) transmission-related societal benefits for possible consideration in ERCOT's transmission planning process and identifies and discusses the benefits and metrics we recommend ERCOT implement in either the near-term or over time as project-specific needs or opportunities arise. And, finally, Section VI presents our recommended improvements for the ERCOT's overall transmission planning process and project selection criteria.

Additional detail is presented in four appendices. Appendix A – Types of Transmission Benefits and the Importance to Consider a Complete Set Of Benefits; Appendix B – Experience with Identifying and Analyzing a Broad Range of Transmission Benefits; Appendix C – Overall Societal Benefits Distinguished from Benefits to Electricity Customers; Appendix D lists the stakeholder entities who provided feedback (a) on ERCOT's long-term transmission planning process during interviews conducted in April 2013; and (b) in response to the draft recommendations we presented during the June 3, 2013 stakeholder meeting; and finally, Appendix E contains the slides from the June 3, 2013 stakeholder meeting during which we presented the findings and draft recommendations of our review effort.

II. ERCOT LONG TERM TRANSMISSION PLANNING

As previously noted, ERCOT's transmission planning process considers two different timeframes. A six year transmission plan called the Regional Transmission Plan (RTP) identifies actionable projects that are usually necessary to meet reliability needs and evaluates near-term economic opportunities. The Long-Term Plan addresses long-term opportunities that might improve on shorter-term plans.

[It] evaluate[s] 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.⁷

Transmission planning in ERCOT is a stakeholder-driven process. ERCOT holds monthly RPG meetings with stakeholders to review the progress being made by ERCOT staff and external consultants towards developing future transmission plans or to refine the planning process. With the expansion of the long term study, joint RPG and LTSTF stakeholder meetings have been held to provide updates of ERCOT analyses specifically on the effort to expand the scope of the long-term study process. The topics discussed during the joint meetings have included future scenario definitions and development, additional modeling tools development, review of scenario-specific intermediate results, such as generation resource plans for each scenario, and review of the final results of the economic analysis.

The joint RPG/LTSTF meetings have provided a forum for ERCOT to receive input from stakeholders on a range of issues related to planning the ERCOT system over the long term.⁸ ERCOT explicitly requests that stakeholders provide input following the meetings to ensure that all comments can be considered.

Based on the work of ERCOT and stakeholder through this process, the scenarios used in the 2012 Long Term System Assessment included⁹:

- Business as Usual with All Technologies (BAU All Tech)
- BAU All Tech with Retirements
- BAU All Tech with Updated Wind Shapes
- Extended Drought
- BAU All Tech with High Natural Gas Price
- Environmental

The 2012 scenario development effort focused especially on the Extended Drought scenario and on load growth forecasts. The Extended Drought scenario required modeling by Sandia National Labs and Black & Veatch of the possible conditions that the ERCOT region may face if the drought of 2011 was sustained over a longer time period. The scenario provided a better understanding of the impacts of a drought.¹⁰ Discussions during the 2012 effort also focused on how the load forecast accounts for unexpected growth from expanding oil and gas sector activities. ERCOT has traditionally used non-farm employment data to forecast future loads, but

⁷ ERCOT, 2012d, p. 6.

⁸ Two additional working groups—the Demand Side Working Group and the Emerging Technology Working Group—have provided forums for stakeholders to include in these specific topics.

⁹ ERCOT, 2012d.

¹⁰ ERCOT, 2012a.

stakeholders voiced concern that it may not properly account for the oil and gas development currently occurring.¹¹

The scenarios developed through the stakeholder process provide a range of assumptions about possible futures that are used for analyzing the ERCOT system over the next twenty years. The range of scenarios considered is summarized in in Table 2.¹² As shown, the scenarios differ in the generation and demand technologies considered, weather, natural gas prices, continuation of the wind production tax credit (PTC), and emissions costs.

Table 2
ERCOT LTS Scenario Definitions

Scenario	Technology	MW	Demand Response	Moody's employment	Weather	Gas Price	PTC Continuation	EMISSION COSTS	Other Policies
S0 Business As Usual	Combined Cycle	10,800	0	Base	Normal	EIA Reference	No	No	
	Combustion Turbine	5,700							
	Wind								
	Solar								
	Admin CT								
S1 Business as Usual All Technologies	Combined Cycle	13,200	Up to 2,700	Base	Normal	EIA Reference	No	No	
	Combustion Turbine	7,400							
	Wind								
	Solar								
	Admin CT								
S2 Business as Usual All Technologies, updated wind Natural Gas Retirements > 50yrs	Combined Cycle	8,500	Up to 2,700	Base	Normal	EIA Reference	NO	No	
	Combustion Turbine	19,700							
	Wind	1,500							
	Solar	10,000							
	Admin CT	13,770							
S3 Business as Usual All Technologies Updated Wind	Combined Cycle	3,600	Up to 2,700	Base	Normal	EIA Reference	NO	No	
	Combustion Turbine	7,140							
	Wind	17,151							
	Solar	10,000							
	Admin CT	17,850							
S6 Business as Usual All Technologies Continuation of PTC	Geothermal	3,600	4,500	Base	Normal	EIA Reference	YES	No	
	Combustion Turbine								
	Wind	23,365							
	Solar	11,000							
	Admin CT								
S7 Business as Usual High Natural Gas Price	Combined Cycle		Up to 2,700	Base	Normal	EIA + \$5	YES	No	
	Combustion Turbine	400							
	Wind	35,975							
	Solar	13,000							
	Admin CT	2							
S9 Business as Usual All Technologies Increased Asynchronous Tie Capability	Combined Cycle	8,400	2,500	Base	Normal	EIA Reference	NO	No	
	Combustion Turbine	680							
	Wind	28,546							
	Solar	7,500							
	Admin CT	27,540							
S5 Drought	Combined Cycle	3600 / 4400 / 10400	A-1000 B-2000 C-NA	Base	2011 Summer	A EIA Ref B EIA - \$2 C EIA Ref	A - No PTC B - PTC C - PTC	A - No B - Yes C - PTC	Water Costs added to New Thermal Reduced HSL due to Hi Ambient Temp
	Combustion Turbine	13090 / 15295 / 170							
	Wind	13031 / 5500 / 68100							
	Geothermal	3600 / 1700 / 3600							
	Solar	11000 / 9000 / 7500							
S8 Environmental	Admin CT	16490 / 15293 / 29410	2,000	Base	Normal	EIA + \$5	YES	Yes	Cross State Air Pollution MATS / NESHAPS No new pulverized coal IGCC Only
	Combined Cycle	2,890							
	Combustion Turbine	70,464							
	Wind	18,000							
	Geothermal	3,600							
S4 Environmental With Demand Response and Energy Efficiency	Solar	18,000	37,451	Base	Normal	EIA + \$5	YES	Yes	10,000MW Demand Response Mandate 15% of Energy by 2025 from Energy Eff
	Admin CT	32470							
	Geothermal	3600							
	Wind	51211							
	Admin CT	4350							

¹¹ ERCOT, 2012b.

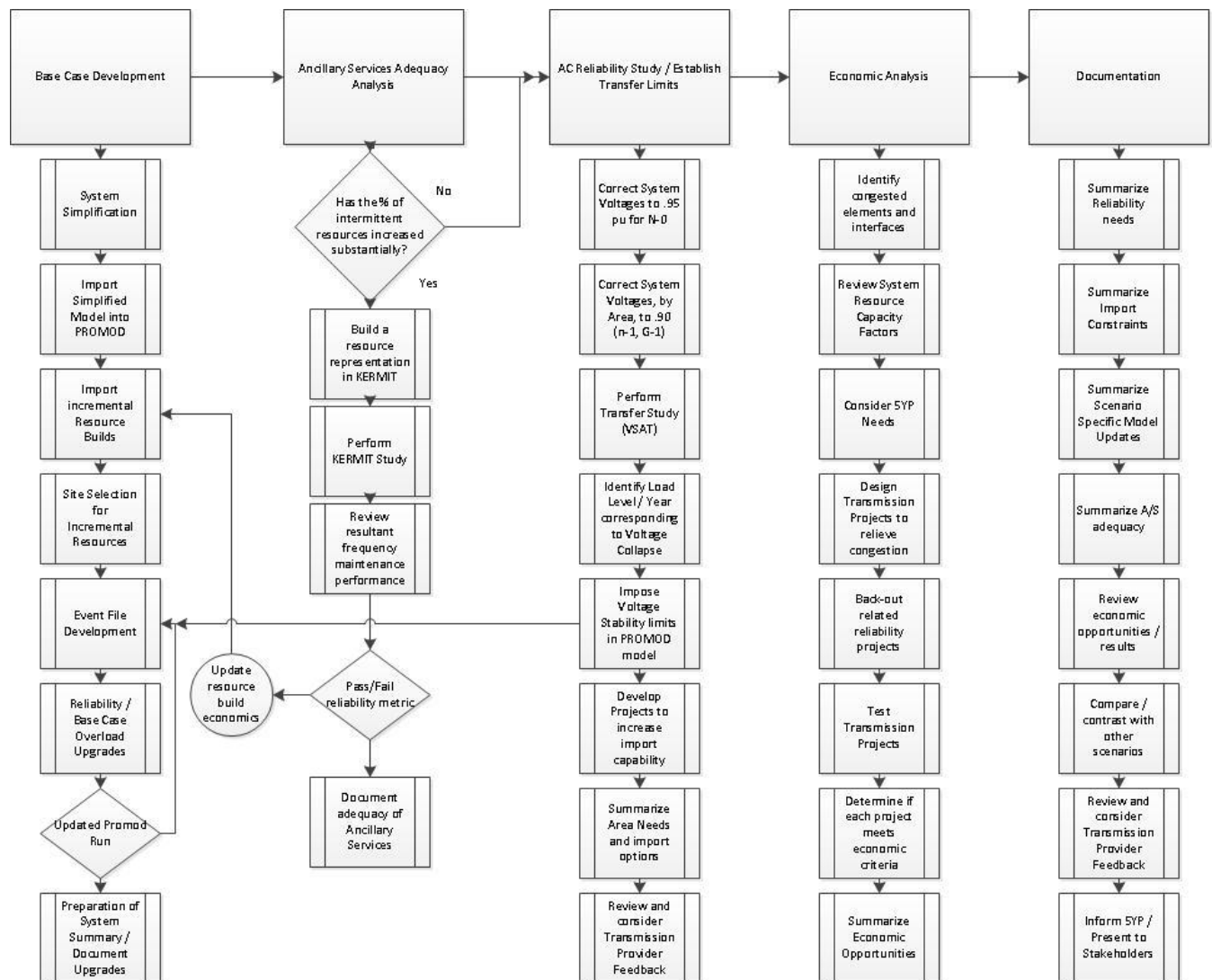
¹² ERCOT, 2013b.

Based on these scenario assumptions and their impacts on expected future load and generation capacity, the ERCOT long-term modeling team developed a process for evaluating transmission needs. Each scenario is analyzed through five major steps, as shown in Figure 1.¹³

For each scenario, a Base Case is developed in the first three steps of the process which identifies generation and reliability-driven transmission additions to the current system before considering new economic transmission projects. To do so, the transmission system is simplified in Step 1 by removing 69 kV and radial 138 kV lines, and incremental generation is added through a process that identifies the specific locations in which the plants are projected to be built. This Base Case is then analyzed for selected individual years to identify necessary reliability-driven transmission upgrades. Steps 2 and 3 then further modify the Base Case to ensure operational requirements are met for each study year. This involves analyzing ancillary service adequacy (Step 2) and alternating current (AC) reliability and stability-based transfer limits (Step 3).

¹³ *Id.*

Figure 1
ERCOT Long Term Transmission Planning Modeling Process



An important step in the process of developing the Base Case is adding new resources to meet the projected future load. ERCOT completes an analysis of where and when future resources will most likely be added in order to then plan the future transmission system. As an example, the resource expansion results from Steps 1–3 of the Base Case analysis are summarized in Table 3¹⁴ for the “Business As Usual (BAU) with All Technologies” scenario.¹⁵

¹⁴ ERCOT, 2012d. Appendix 4, p. 1.

Table 3
BAU with All Technologies – Resource Expansion Analysis Results

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	GW/hs	-	29.9	22.0	38.2	40.3	42.7	59.5
SO ₂	Tons	354,033	354,439	357,113	356,594	356,561	356,502	357,857
CO ₂	(k) Tons	229,961	247,892	251,225	264,772	272,112	280,358	290,395
NO _x	Tons	129,480	138,280	139,958	143,322	143,939	145,780	148,097

Once Base Cases have been developed for the selected study years that include all generation resources and necessary reliability-driven transmission upgrades, ERCOT completes an Economic Analysis (Step 4) in which potential economic transmission projects are identified by reviewing congested elements and interfaces, reviewing system resource capacity factors, and considering needs identified in the near term analysis. ERCOT also provides an opportunity for stakeholders to suggest potential economic projects for consideration.

Once identified, the economic transmission projects are added to the Base Case (defining a “Change Case”) to determine the production cost savings that would be realized in the study year, which represents the assumed first year of the new line’s operations. These production cost savings are estimated as the difference between simulated production cost savings in the Change

¹⁵ The results of the Business As Usual with All Technologies scenario are provided here to demonstrate the ERCOT transmission planning process as it provides the base projections that ERCOT developed to use in its long-term transmission modeling for one of the long-term scenarios. Several of the other scenarios are variations based on adjustments to this scenario.

Case and the Base Case. In addition, ERCOT analyzes whether the economic project can defer or avoid any of the reliability projects previously added to the Base Case in the particular study year.

To determine whether economic transmission projects are cost effective, ERCOT compares the net costs of the economic project (net of the costs of the avoided or deferred reliability projects) for the study year to the benefits estimated through the production cost simulations for the same year. Economic projects are determined to pass the economic criteria if the first year revenue requirement for the adjusted capital costs of the economic projects is greater than the first year production cost savings of the economic transmission project. Consistent with Public Utility Commission of Texas (PUCT) orders, ERCOT approximates first-year revenue requirement by assuming that it is 1/6 of the projects' capital costs.

As an example, the results of this economic analysis for the “BAU with All Technologies” scenario are summarized in Table 4.¹⁶ As shown in this example, only one minor economic project, the upgrade of the Green Bayou 345/138 kV line, was found to be economic.

Table 4
BAU with All Technologies – 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

¹⁶ ERCOT, 2012d. Appendix 5, p. 5.

The long-term study results are presented at monthly RPG meetings as they are developed. They are then summarized in ERCOT's annual Long-Term System Assessment. As stated above, the goal of the LTSA is to inform participants in the transmission planning process of potential economic transmission lines that are robust across scenarios. The potential projects identified in the LTSA may subsequently be considered in the (near-term) RTP process, when more information is available about future market conditions. In addition, the LTSA results may not be project-specific but, instead, provide information about areas where transmission upgrades may be economically efficient in the future. For example, the 2012 LTSA concluded that "the Houston Region will need at least one additional import path within the next ten years."¹⁷

¹⁷ *Id.*, p. 42.

III. STAKEHOLDER COMMENTS REGARDING THE LONG TERM PLANNING PROCESS

Stakeholder involvement is critically important to the success of long term transmission planning. Therefore we have engaged stakeholders throughout our evaluation process, including (1) conducting an initial kickoff meeting to the RPG, (2) interviewing stakeholders, (3) presenting our draft recommendations at a stakeholder meeting, and (4) collecting stakeholders' feedback on our recommendations.

During the kickoff meeting we presented our proposed approach and requested opportunities to discuss the details with stakeholders who were willing to be interviewed. We then interviewed every stakeholder who had indicated an interest to speak with us, including representatives from utilities, transmission developers, generators, industrial consumers, landowners, market analysts, and the ERCOT Independent Market Monitor.

Our goal in interviewing stakeholders was to better understand the stakeholders' views on:

- The existing long term study planning process and assumptions;
- The role and effectiveness of the long term study in the overall transmission planning process;
- The role of transmission owners and other stakeholders in the process;
- The benefits of transmission; and
- Other areas of concern for each stakeholder.

We received a wide range of viewpoints from different stakeholders during the interviews and have included our summary of their specific comments here without attribution to specific stakeholders. We have also considered these viewpoints in providing our recommendations to ERCOT.

A. SUMMARY OF STAKEHOLDER COMMENTS

Purpose and Value of Long-Term Planning

Overall, stakeholders generally were appreciative of the efforts being made by ERCOT to plan the transmission system beyond the near term and a subset of stakeholders felt there was significant value in ERCOT conducting long-term studies to inform transmission planning and have expressed hope that as ERCOT and stakeholders become more familiar with the new process, the long-term nature of the process will enhance planning over time. However, some stakeholders expressed concerns about the usefulness and effectiveness of the current process for implementing long-term planning, including a subset of stakeholders who questioned the need for long-term analyses at all, given the significant uncertainties in the outer years and the fact that the needed transmission can be built relatively quickly (*i.e.*, within the near-term planning

time frame) in Texas. We attribute the concerns about the usefulness and effectiveness to the lack of clarity around how the results would be used.

Overall, stakeholder viewpoints are quite diverse and we summarize them below:

- A stakeholder highlighted the fact that the LTSA **process is relatively new and it is a good start** for examining the transmission needs in ERCOT from a long-term perspective. Because of uncertainties about the future, any such long-term perspective needs to include the use of scenario-based planning. While not aligned with all stakeholders' own perspectives about the future, the current effort begins to lay out a foundation from which the planning processes and scenario development can be improved over time.
- Some stakeholders support having a long-term planning process that allows planners to **look at larger projects** instead of simply relying on incremental, reliability-based builds and to include long-term benefits when making decision about projects.
- Some have suggested that it would be valuable for ERCOT to **aggregate all the issues** that ERCOT is trying to solve with transmission and allow stakeholders and transmission developers to propose solutions.
- Most, but not all, stakeholders believe that there **could be significant value** in conducting the long-term planning, particularly in the context of discussing what the grid would need in the long term.
- Some stakeholders believe the long-term study should serve as a basis for establishing **long-term benefits for various transmission projects** and that it may be particularly helpful when comparing more expensive solutions that can provide greater long-term benefits against cheaper solutions that focus primarily on the short-term issues.
- Several stakeholders recognized that the LTSA provides valuable information on long-term benefits when deciding between short-term and longer-term alternatives. It **should thus generate conceptual projects that can be studied further** as different future scenarios play out.
- Many stakeholders acknowledge the value of looking beyond five years to develop the economic projects, but some stakeholders have expressed concern that the estimated future market conditions, generation development, and **transmission benefits in the outer years (20 years) may be too uncertain or speculative** to be useful for transmission planning.
- Some stakeholders suggested **reducing the long-term planning timeframe to 10–15 years** instead of the 20 years currently used.

- A stakeholder expressed a strong preference for using only the short-term RTP process for transmission planning and believes **looking out further is not necessary** for ERCOT since many projects resulting from the short-term planning process have been built already and the 20-year long-term planning process **relies too heavily on projecting uncertain futures**, particularly since constructing transmission can be done relatively quickly in Texas.
- Some stakeholders have expressed the concern that the information used in the LTSA is not considered in the short-term planning and, consequently, **does not affect the proposed actionable projects**.
- Several stakeholders have expressed concerns that the planning process only yields local reliability-based transmission projects for which incumbent utilities have the right-of-first-refusal to build, **limiting the involvement of independent developers**.
- A stakeholder pointed out that critical reliability projects seem to be a priority in the permitting process in Texas as those projects are faster to approve than longer-term projects. The combined effects of focusing primarily on reliability projects and a shorter permitting process for those projects tend to result in **ERCOT continually developing only reliability-based projects** after they become “critical.”
- Some have expressed their understanding that the LTSA is simply a screening tool for projects to assess future grid issues and uncertainties and not to produce specific projects to be developed. With this understanding, some suggested that perhaps the **long-term plan could yield projects that can be studied in future short-term plans** as scenarios play out.
- One stakeholder believes the transmission planning process has provided too many out-of-market incentives for developing emerging technologies and that ERCOT is becoming a facilitator or even a promoter of new technologies. Instead, ERCOT should **focus more on interconnecting generators** than on the longer-term and speculative needs of the system.
- A stakeholder is concerned that ERCOT appears to favor transmission investments that are paid for by ratepayers over generation solutions.

Scenarios Development and Associated Results

Many stakeholders showed particular interest in the future scenarios that were developed to inform the long-term transmission planning effort and appreciated that the process was driven by stakeholder involvement. Some were concerned that many of the chosen scenarios may be unrealistic and that their input was not fully considered. Stakeholders consistently commented that the results of future long-term studies will only be accepted if a wide range of stakeholders

believe that the scenarios and associated inputs are reasonable. There was general agreement that the current scenarios will need to be refined further and that increased stakeholder engagement will be needed to ensure consistent understanding and “buy-in” to the long-term planning results. Some stakeholders thought the scenarios were too similar and recommended that a more divergent set of scenarios be developed to help identify weaknesses in the transmission system and to allow for the development of a more robust transmission grid.

- Some stakeholders believe that the **long-term planning process is an effective way to address a large number of planning challenges** such as resource alternatives, carbon policies, and future generation locations, and it provides an opportunity for stakeholder input to these system issues.
- Some stakeholders are generally satisfied with the range of scenarios used in the long-term planning process, particularly because they were the result of the stakeholder process.
- Some believe that it is **very important to obtain stakeholder buy-in** from the very beginning of the process of defining credible scenarios
- It is also important to **obtain buy-in from both the ERCOT Board and the Public Utility Commission** from an early stage of the long-term planning process.
- Some stakeholders believe that the future scenarios used in the long-term planning process **need to be more realistic** and that it is extremely important that there is an avenue for the stakeholders to discuss scenarios, inputs, and sensitivities
- Some have expressed the concern that the current long-term planning process **is not linked to ERCOT’s strategic planning** process.
- Some stakeholders emphasized that it is **very difficult to forecast load and particularly generation developments that far into the future.**
- Some expressed the concern that the **scenarios currently used are too similar** and therefore do not yet capture the potential future uncertainties or the transmission options to address future needs.
- Some stakeholders have expressed **concern about the credibility of the scenarios** and if the scenarios employed in the long-term planning process are not credible to the stakeholders, then the results would not be meaningful enough to affect transmission planning in the near-term.
- Some stakeholders are particularly concerned that the **scenarios do not capture the full breadth of uncertainties and possible future outcomes.** Some stakeholders strongly

recommend that more “stress scenarios” be explored to identify system weaknesses and solutions that lead to a more robust transmission grid.

- Some suggested that for the long-term planning process to be effective, it should **provide a more visionary look at the future**, with input from a wider range of stakeholders (*e.g.*, legislators, industrial customers, the oil and gas industry), to develop a wider range of possible, even extreme scenarios.
- Several stakeholders have expressed a strong impression that the scenarios and proposed solutions **do not yet incorporate the knowledge of those who know their local system** the best, including load growth on their systems and the feasibility of certain proposed projects. Some have suggested that ERCOT should build bottom-up long-term load forecasts incorporating the information that local utilities have.
- Some have expressed the concern that the scenarios incorporate very specific assumptions about the location of load and generation and that even **a slight change in locational load or generation would lead to very different transmission solutions**. This could lead to some degree of lack of support for the scenarios and associated transmission solutions.
- Some stakeholders suggested that the cost of **developing conventional generation in different locations should be studied more thoroughly** and that low-cost locations be considered in long-term transmission planning, similar to the wind zones considered in the CREZ process.

Level of Stakeholder Involvement

Most stakeholders expressed considerable interest in continued involvement in long term planning, especially in the development of scenarios and in reviewing results. Several stakeholders hoped that ERCOT would more deliberately incorporate input from transmission owners with specific local knowledge. A few stakeholders expressed concerns about their ability to be involved in the process due to the highly technical nature of the discussions, the significant commitment of time and resources needed for participation, and the currently limited use of long-term study results.

- Most but not all stakeholders **appreciate the special effort ERCOT** has made to invite and welcome input and feedback from stakeholders.
- Some stakeholders believe that the first cycle of LTSA has already worked through a lot of key issues and **has laid a good groundwork for future iterations** and improvements to the planning process.

- Some of the transmission owners feel that **ERCOT could rely more on their local expertise** in the long-term planning efforts.
- Some of the non-technical stakeholders **find it difficult to participate in a technically challenging process** where they have limited capabilities to understand the process, limited information available to them, and limited assurance that their concerns are being represented by either ERCOT or the Public Utility Commission.
- Some wanted to know **how to become more involved** in the overall planning process so that they are not surprised with the results.
- Some stakeholders suggest that ERCOT **be more open to allowing parties to participate as stakeholders** and to find ways to ensure that stakeholders have sufficient time to review and react to proposals made by ERCOT.

The Scope of Transmission Benefits Considered

Many stakeholders were receptive to considering additional categories of benefits in the transmission planning process. Some stakeholders expressed that transmission investments offer many benefits that should be, but have not yet been, considered in ERCOT's planning process. In contrast, some are concerned that considering additional benefits will lead to an increase in unnecessary transmission build-out that could adversely affect electricity customers, land owners, and possibly other market participants. A few stakeholders also suggested broadening the scope of costs considered in the long-term study process, such as the costs of balancing the intermittent resources that are facilitated by new transmission lines and the cost associated with lost land value. Several stakeholders also suggested that ERCOT and the PUCT consider electricity customer benefits metrics in addition to relying solely on societal benefits.

- Some stakeholders **would like to see projects that provide benefits to electric customers**, rather than being limited by a narrowly-defined "societal" perspective.
- Some stakeholders expressed that, even if not used to make project decisions, the **benefits of transmission to customers** should be made clear.
- On the other hand, some stakeholders want to **make sure that only societal benefits** are considered.
- Some stakeholders expressed the view that ERCOT's **current planning process and market simulation assumptions substantially understate transmission-related benefits**. Specifically, some have indicated that both near-term and long-term planning significantly understate transmission-related benefits by not adequately considering: load uncertainty, generation outages/availability, planned and forced transmission outages, fuel price volatility, real-world ancillary service procurement and generation

commitment, actual operational transmission limits that are well below simulated limits, uncertainty in wind generation, and possible future changes in environmental regulations.

- Some believe that **transmission can help increase market competition and liquidity** and therefore should be considered in the benefits metrics; however it is unclear how much of an impact it would have in ERCOT considering that market power is mitigated.
- Some stakeholders have expressed a **concern that costs and benefits carry different degree of uncertainties** and such differences should be reflected in the analysis.
- Other stakeholders are **concerned that consideration of a more expansive set of benefits, particularly over the long term, will result in overbuilding transmission**. They suggest that long-term costs (such as those associated with renewable integration, lost right-of-way, degradation of land value, and associated environmental impacts) should be considered as well.
- Some have expressed a **concern that the existing benefit-to-cost test sets an artificially high hurdle**.

Other Feedback

- Some stakeholders would like the **results of the ERCOT analyses to be better communicated**, preferably in layman's terms, and to make sense and be meaningful and practical, despite all the complex modeling processes used.
- A stakeholder believes that although ERCOT shares results with Transmission Service Providers (TSPs) prior to the Regional Planning Group, they **do not have enough time to provide constructive input**.
- Some stakeholders expressed that they are **not sure how to propose new project ideas without giving away confidential information** to potential competitors.
- Some expressed the **importance of non-transmission alternatives** and noted that ERCOT currently does not have a process that considers those alternatives before deciding on a transmission project.
- Some stakeholders expressed **the need for high-level leadership to drive change** in the ERCOT process and to educate the Board and Commission on the legitimacy of the approach.

B. RECOMMENDATIONS BASED ON STAKEHOLDER COMMENTS

Based on our interviews and the comments of ERCOT transmission planning stakeholders, we believe ERCOT has an opportunity to increase stakeholder participation and, in doing so, improve the transmission planning process. We recommend:

- ERCOT should **sharpen the goal definition of Long-Term Planning and establish how results generated through Long-Term Planning will influence “actionable” Regional Transmission Plans.** We recommend that, as ERCOT refines the long-term planning process, specific processes and communications are put into place to ensure that “results matter” and stakeholders understand how they matter. This will require that ERCOT articulate how the long term planning results will be used in the RTP in a more formalized manner.
- ERCOT should **reiterate their invitation to all potentially interested parties to participate in the stakeholder processes** and increase the level of stakeholder engagement and comfort. This could be accomplished by placing more attention on developing the scenarios and obtaining a more wide-spread buy-in from stakeholders about the assumptions and scenarios. Even if not everyone agrees to the assumptions and scenarios, ERCOT should increase stakeholder engagement in their development. Further, local system knowledge should be considered or solicited more actively when developing project ideas.
- ERCOT should put into place specific processes to ensure that the results of the long-term planning are trusted by stakeholders. This can be accomplished by **conducting a workshop on scenario development that will involve stakeholder representatives** from each sector within the electric power industry and experts from outside of ERCOT and the power industry to share views of the future and document the collective results from the scenarios developed.
- ERCOT should **ensure that scenarios developed by the stakeholders are well documented**, shared with all stakeholders, and understood.
- ERCOT should **clarify for its stakeholders the types of transmission benefits and costs considered** in its analysis by conducting special workshops that focus on stakeholders gaining a detailed understanding of all the benefit metrics and how the benefits will be compared to the costs.

IV. REVIEW OF ERCOT’S MODELING PRACTICES AND INFRASTRUCTURE

As part of our assessment of how to identify economic transmission projects more effectively within ERCOT’s long-term planning process, we interviewed ERCOT modeling staff and reviewed their documentation. Our objective was to identify opportunities for improving the modeling process steps, refining the modeling execution practices, and training ERCOT staff (if needed) on how to evaluate the types of transmission benefits already included within the current LTS scope. Such improvements were intended to complement the expansion of benefit categories addressed in Section V and the enhancement of evaluation criteria discussed in Section VI.

This section of our report summarizes our model-related findings and recommendations for ERCOT to consider. We first provide a short description of how we conducted our assessment, followed by a summary of both what is working well and where there are areas for improvement. Finally, we present for further consideration by ERCOT our recommendations related to ERCOT’s modeling team and practices.

A. HOW WE CONDUCTED OUR ASSESSMENT

The starting point for our assessment was ERCOT’s existing documentation of its modeling processes. The most important documents we reviewed were: ERCOT’s “Long Term Study – Transmission Analysis” (version 1.0); “Long-Term System Assessment for the ERCOT Region,” (Dec. 2012); ERCOT’s “2012 Five-Year Transmission Plan Study Scope and Process”; and “Transmission Needs Analysis Scenario 2/3 Update,” (Oct. 12, 2012). We also reviewed sample results from the long-term (LT) group’s PROMOD IV simulations.

After reviewing ERCOT’s documentation of its modeling practices, we conducted interviews with each of ERCOT’s three modeling groups: the LT, the mid-term (MT), and resource adequacy (RA) groups. The interviews were conducted via conference calls—two rounds for each group, plus additional follow-up calls.

B. WHAT IS WORKING WELL IN THE MODELING PROCESS

Overall, we found that ERCOT’s modeling processes are well designed and documented, and the modeling team members demonstrated strong expertise in transmission and economic modeling, with no identified need for additional market simulation training.

Several modeling techniques used by ERCOT are best-in-class. An example is ERCOT’s methodology for adding future generation to the model where most economic (considering factors such as environmental siting challenges in load pockets, fuel supply, and locational market prices, or LMPs)—although the process should continue to evolve to consider improved estimates of locational cost differences and the indirect costs that certain resources (such as intermittent generation) impose on the system. Similarly outstanding is the teams’ use of

transmission reliability models alongside economic models. For example, within each scenario, ERCOT's modeling approach identifies reliability needs before evaluating the economics of new transmission that could be added to the already-reliable Base Case, sometimes avoiding the need for reliability upgrades. The teams also make sure they are modeling transmission constraints (including contingencies and voltage-limited interfaces) properly in each case they run, especially when modeling major additions of resources or transmission. These practices help capture shifts in congestion patterns that are important for assessing transmission benefits.

We found that all team members demonstrate strong expertise in transmission and economic modeling, and a sound understanding of how the economic and reliability models can interact. The staff has considerable accumulated experience from recent studies and prior work; and with their growing experience with the long-term planning process, they will likely be able to execute future studies even more smoothly than the current set of initial studies. Team members would not need any additional training, except as needed to expand the scope of benefit categories evaluated (see Section V) and to enhance the criteria used to evaluate transmission projects (see Section VI).

Finally, we found that the modeling team has been clearly documenting its process steps. The prepared documentation is thorough and makes use of well-constructed flow charts and maps. The LTSA report and RPG presentation materials provide many good examples of such documentation.

C. RECOMMENDATIONS FOR POSSIBLE IMPROVEMENT

We identified three general areas where current practices may not support the transmission planning process as effectively as they could. These areas are summarized briefly below and then are discussed more extensively in the subsections that follow.

- **Bifurcated Organizational and Modeling Team Structure:** ERCOT has two separate sub-groups, each with its own production cost model and its own set of inputs covering different timeframes. This creates duplication of work and risks inconsistencies in the modeling efforts. Having separate modeling teams also hinders the exchange of ideas and best practices between teams working on similar issues. Moreover, the lack of a single, coherent multi-year modeling platform limits options for considering the economic value of long-lived assets in an evolving future, as discussed in Section VI. We understand that ERCOT has already begun to address this concern by re-organizing the teams' structure to make the structure more efficient and consistent.
- **Designing Study Cases:** ERCOT could improve its modeling by defining selected scenarios in a way that is more credible to stakeholders. Other potential improvements include more fully representing generation outages (and other system stresses in the context of additional benefit metrics) that regularly increase congestion. Study cases

should also be defined carefully to distinguish between alternative and complementary transmission projects when evaluating portfolios of projects.

- **Validation of Results:** ERCOT performed some model validation in the past when the modeling tools were initially developed. Such model validation and calibration efforts should be undertaken on a more regular basis to ensure that the market simulations can reasonably represent actual market conditions, market prices, and congestion patterns. It would also be helpful to add process steps to ensure that the reasonableness of simulation results is evaluated from a higher-level perspective.

1. Bifurcated Organizational and Modeling Structure

The historic evolution of a mid-term RTP process that is separate from the long-term planning process resulted in separate modeling teams using two different production cost models. ERCOT has already begun to better integrate its modeling team structure, so our concerns reflecting the structure (as we found it when we did our assessment during early 2013) may be at least partially resolved.

We found that two different parts of the RA group provide supply and demand inputs to two separate economic models and modeling groups: one part of the RA group provides the MT Modeling group with all non-transmission data for populating UPLAN for study years 0 to 6; and another part of the RA group provides the LT Modeling group all non-transmission data for populating PROMOD IV for later study years (years 10 to 20). Maintaining two economic models requires extra work populating the models and validating results. Having different groups simulate different timeframes also risks inconsistencies that may make the planning effort less effective. For example, the last year of the MT Modeling case and first year of the LT Modeling case (used only for siting new generation) typically simulate the same year. However, model inputs (generation additions, contingency files, *etc.*) are different due to their different sources. Creating the contingency file is one of the most time consuming efforts for the LT Modeling group. The LT Modeling group does borrow the list of multiple-element contingencies from the MT Modeling group (while generating single contingencies independently), but substantial work is required to implement them in PROMOD IV.

The RA, MT Modeling and LT Modeling sub-teams were isolated without free flow of information among them. Until recently, these three groups were all separate teams. Even with the MT and LT Modeling groups now merged, the RA group is still physically separate on a different floor. Most team members are not fully aware of what the other groups do—how they develop inputs, run their models, and validate the results. There is little information flow between the MT and the LT Modeling groups, except the transfer of a 5-year load flow case and some discussion of reliability and economic solutions to consider (nor is there coordinated communication with the transmission owners). There is little flow within the RA group among those who populate the UPLAN model and those who populate the PROMOD IV model. As a

result, there is sub-optimal sharing of complementary ideas and expertise. This can create inefficient workflow relative to what we experienced with more integrated teams.

In addition, individuals in the RA group may have many years of experience running PROMOD IV but may not be part of the PROMOD IV modeling effort. Because the RA group is located on a separate floor, this creates a barrier to casual interactions that could enable the PROMOD IV modelers to take full advantage of the expertise and knowledge these individuals could provide. Furthermore, we learned that individuals tend to focus on a narrow area of the modeling effort and, while they can validate accuracy in that area, nobody is evaluating the reasonableness of results from a higher-level perspective. Because each sub-team lacks knowledge about the other teams' approaches, it is difficult to develop a higher-level perspective of the reasonableness and efficiency of the overall effort.

Bifurcation of the teams and models also makes it almost impossible to consider some important aspects of long-lived assets in an evolving future, such as: advancing reliability or economic projects that have been identified in the long-term study; evaluating the present value of estimated project costs and benefits; and assessing the option value of project modifications that lessen the cost of meeting long-term needs that may occur in some scenarios. These points are discussed further in Section VI.

We recommend that ERCOT consider addressing these challenges by consolidating both its modeling platforms and modeling teams. First, ERCOT should consider putting the entire modeling staff in one contiguous space to encourage closer collaboration. All team members need to understand the high-level objectives and methodologies for addressing both reliability and economics across the different time frames. Specialization may be necessary, but it should be organized around models or disciplines, not timeframes. There could be two load flow modelers, several people who develop the various inputs (including the resource expansion plan), run PROMOD IV or UPLAN, and interpret results over all timeframes studied. One or two other staff members might run KERMIT, to evaluate ancillary service needs. Second, we recommend that ERCOT select a single economic model—for example, either PROMOD IV or UPLAN. We understand that ERCOT plans to select a preferred model later this year.

2. Designing Study Cases

Although many aspects of the study cases are well-designed, other aspects could be improved. Improvements are possible particularly in the areas of scenario development, representation of stress conditions that regularly exacerbate congestion costs, simulating portfolios of projects versus individual projects, and technical modeling matters. Our recommendations regarding improving scenario development are discussed further in Section VI.E.

Representation of Stress Conditions. Models such as PROMOD IV and UPLAN will understate the value of transmission if they are used to simulate only ideal system conditions that do not

represent a realistic level of transmission congestion. The current simulations are based on weather-normalized peak loads and monthly energy without transmission outages and, at least for long-term simulations, without forced generation outages. This will tend to understate congestion costs and the value of transmission upgrades by neither subjecting the system to a realistic amount of stress nor fully accounting for the marginal cost of energy during stress periods.

As explained further in Section VI, some types of stress conditions should be included only in special scenarios or sensitivity cases, due to their irregularity and due to modeling complexities. Such conditions include a full range of weather conditions (such as the 2011 heat wave or the drought conditions ERCOT has already included as a future scenario), transmission outages (which are not traditionally included in production cost simulations but should be considered to estimate the full value of transmission investments), and congestion arising from differences between day-ahead forecasts and realized loads and renewable generation output.

We also understand that forced outages of generating plants are not considered in ERCOT's long-term simulations. We recommend, however, that forced generation outages should be added to all cases to better approximate actual congestion levels. Modeling random forced outages (and holding them constant across simulation cases) is standard industry practice, although some simulations approximate them as unit de-rates. The random approach is better because it includes a more realistic level of variability. However, adjustments are sometimes needed if a particular forced outage schedule has undue influence on the results.

In addition to modeling stress conditions due to weather and outages, it is important to model system costs accurately under scarcity conditions. Results from the reviewed simulations appear to understate costs—even during drought conditions, which is the only simulated stress condition we observed.¹⁸ For none of the modeling cases, simulated LMPs reach scarcity pricing levels reflective of actual marginal system costs or suppliers' bidding behavior under certain system conditions. During periods of (perhaps localized) scarcity, the magnitude of congestion costs would be more realistic if the model were adjusted to include a scarcity pricing function. This is particularly important for ERCOT as it is operating under an energy-only market. We recognize that ERCOT's scarcity pricing rules are still evolving, as the Commission considers various "Operating Reserve Demand Curve" proposals. However, even before the Commission defines the final rules, scarcity pricing can be implemented in PROMOD IV to reflect more realistic market conditions. The most straightforward way is to hold aside a realistic amount of operating reserves (including regulation reserves) and then apply an inclining penalty price on depleting those reserves. An alternative is to maintain reserves and dispatch dummy units at various

¹⁸ Note, however, that the drought case simulations assume recurring years of similar conditions such that the long-term generation mix and expansion/retirement can be optimized for these conditions. This will tend to significantly understate the impact of stress conditions on a system that was not specifically optimized for an assumption that such conditions would be encountered every year.

scarcity price levels. In this context, it is also important that the model realistically reflects which units provide operating reserves.

Model Setup. We also offer the following recommendations regarding model setup:

- *Portfolios of Transmission Projects to Simulate.* The current approach of evaluating each candidate project individually is time-intensive and yet does not directly inform whether multiple projects would be more economic in combination. In many cases, it will be perfectly appropriate to simulate individual projects. However, in some cases, combining projects with complementary purposes can reduce the time needed for the analyses and better represent the benefits of the portfolio when simulated jointly. If it is necessary to clarify the incremental value of each project in a group of complementary projects, adding projects sequentially during the analysis would be a possible approach.
- *Comparison of Appropriate Change Case to Base Case.* The evaluation of a candidate economic project's production cost benefits involves the comparison of a "Change Case" with the proposed line to a "Base Case" without the line. Currently, we understand that both the Base Case and Change Case may currently include the same group of reliability upgrades that were developed as a part of the Base Case. However, if the economic project's benefits include deferral or avoidance of certain reliability projects, those reliability projects should be removed from the Change Case that includes the proposed economic project.
- *Voltage Analysis of Interfaces.* The "AC Reliability Study/Establish Transfer Limits" part of the long-term planning process involves adding reliability upgrades to the interface definition, then increasing the interface limit based on an AC reliability analysis. Many other analysts skip that step, instead leaving the new line out of the interface definition and holding the interface limit constant. It is not clear whether the more complicated approach changes the results very much. ERCOT could test whether it does. If the simplified approach does not significantly change results, ERCOT could consider skipping that step in an effort to streamline the analysis. We also note that the AC analysis is performed only for peak summer conditions.
- *System Simplification.* The long-term Base Case development starts with a simplification of the transmission system, including removal of low-voltage buses. This step could more easily be accomplished by simply "commenting out" (or raising the limit) of the relevant constraints without actually modifying the load flow cases.
- *Network Model Handoff.* The load flow case provided to the MT group frequently has open lines, busses missing, and other problems that must be resolved before running UPLAN or PROMOD IV. Our understanding is that the Network Modeling group would be better equipped to resolve these problems, such that the LT group would receive the

load flow case that has already been tested and validated by the Network Modeling and MT groups.

3. Validation of Simulation Results

Electricity market simulation models are complicated representations of an even more complicated electricity market. Thus, even if all model inputs appear reasonable, the results cannot be relied upon unless they are validated against actual market conditions. We have not evaluated whether the long-term simulation results are reasonable but, instead, evaluated the adequacy of current validation measures.

Model validation should include comparisons to actual market conditions (such as market prices, generation dispatch, and congestion levels), comparisons across cases, and high-level assessments to ensure that the results are reasonable. We understand that ERCOT is already performing some of these validation efforts but recommend additional measures.

Comparison to actual market conditions. We learned from the RA group that it had conducted some comparisons to actual market conditions when the model was first developed. We do not know how extensive these efforts were, but, in any case, validation should be undertaken more frequently as market conditions evolve. One of the most effective validation exercises is to develop a “back-cast” (or at least a near-term forecast) and compare simulation results to actual recent market conditions, focusing on price duration curves at major hubs, locational price differentials, capacity factors of dispatched generation resources, total congestion charges, and congestion duration curves on major constraints.

Comparison across cases. New cases should be compared to already-accepted simulation cases to ensure that the model is accurately incorporating the intended input changes. This requires preparing simple diagnostic reports for each run and analyzing differences to prior runs. The LT group’s PROMOD IV simulation reports we reviewed contain much of the basic information one would need, and they were similar to the PROMOD IV reports that Ventyx, the model developer, uses. Many PROMOD IV modelers have become comfortable with such reports and believe they are adequate. In our experience, however, these reports do not make it sufficiently easy to identify anomalies in simulation results. We thus recommend the use of diagnostic reports that show annual unit-level performance data on one sheet and transmission constraints data on another sheet, with each sheet also comparing the generation unit transmission constraint data to a prior case (such as the Base Case or the prior run in a series of development runs). These comparison sheets can be sorted to easily identify the most significant changes, which often point to simulation or input errors of the draft model runs. We provided samples of such diagnostic reports that we produce automatically every time we perform a simulation, using customized queries and macros. ERCOT could use similar queries and macros to automate the compilation of similar diagnostic reports.

High-level review of simulation results. One team member noted that the simulation results are not being reviewed from a high-level perspective to make sure results made sense overall. Instead, it appears that specialized engineers each focus on only their portion of the overall analytical process. It would be helpful to add process steps involving review by analysts with a higher-level perspective, such as the reasonableness of case definitions and simulated market conditions. This may already be happening, but not all team members are aware of it.

V. REVIEW OF ERCOT'S TRANSMISSION BENEFIT METRICS

Developing a robust business case for economic transmission projects requires the economic value of transmission investment to be fully captured in terms of the benefits it can provide to the system. This makes it necessary to account for all costs and benefits over the useful life of the projects, properly considering uncertainties and discounting estimated costs and benefits over time. Because the benefits of transmission investments are measured in large part as a reduction in system-wide costs, conservative estimates of transmission benefits or a failure to consider the full range of economic benefits of transmission investments is equivalent to understating the potentially very costly outcomes that market participants would be exposed to in the absence of these investments. It is consequently preferable to: (1) accurately estimate the full expected value of the benefits that transmission facilities can provide; while also (2) explicitly analyzing the uncertainty around these expected values to better understand the risks of incurred or avoided high-cost outcomes. This section of our report assesses the scope of economic benefits considered by ERCOT in comparison to evolving industry practices.

A. ERCOT BENEFIT METRICS VERSUS INDUSTRY PRACTICES

ERCOT currently considers two types of economic benefits in its planning efforts for economic transmission projects: (1) production cost savings, and (2) benefits related to deferred or avoided reliability upgrades. These two metrics do not capture the full societal benefits of transmission infrastructure investment. While estimating and using these two benefit metrics represents a good starting point, they reflect a narrow subset of the wider range of benefits that are increasingly considered in the industry today, including by other system operators in Texas and surrounding regions. In order to help ERCOT benefit from the quickly evolving industry experience, we summarize the types of transmission-related economic benefits quantified and considered by other system operators in other parts of the U.S.¹⁹

Over the past decade, several RTOs have significantly expanded the scope of the transmission benefits considered in their planning efforts to include a range of economic and public-policy benefits. Initial steps were taken by CAISO in 2004 to support the planning of multi-utility, multi-purpose, and renewable integration projects. RTOs in regions with significant renewable generation potential, such as SPP and MISO, have similarly expanded the scope of the transmission benefits considered in their planning processes—particularly in efforts to better coordinate transmission planning for the integration of renewable resources.

In Texas and its neighboring states, SPP's Integrated Transmission Planning process (ITP) has similarly moved towards examining a broader range of transmission-related benefits in its "Priority Projects" evaluations, such as production cost savings, reduced transmission losses,

¹⁹ This discussion is in part based on the work undertaken during January through July 2013 for the WIRES group. See Chang, *et al.*, 2013.

reduced emissions, and reliability benefits. The full list of benefit metrics considered is shown in Table 5 below. Along with the benefits for which monetary values were estimated, the SPP's Economic Studies Working Group also agreed that a number of transmission benefits that require further analysis include:

- Enabling future markets;
- Storm hardening;
- Improving operating practices/maintenance schedules;
- Lowering reliability margins;
- Improving dynamic performance and grid stability during extreme events; and
- Societal economic benefits.²⁰

In order to support cost allocation efforts, SPP's Metrics Task Force (MTF) has further expanded SPP's frameworks for estimating additional transmission benefits to include the value of reduced energy losses, the mitigation of transmission outage-related costs, the reduced cost of extreme events, the value of reduced planning reserve margins or reduced loss of load probability, the increased wheeling through and out of revenues (which can offset a portion of transmission costs to be recovered from SPP's internal loads), and the value of facilitating public-policy goals.²¹ MTF also recommended further evaluation of methodologies to estimate the value of other benefits such as the mitigation of costs associated with weather uncertainty and the reduced cycling of baseload generating units.

Similarly, MISO—soon to be the system operator for the Entergy region, including Entergy's service area in the southeastern portion of Texas—estimates the value of a broad set of transmission benefits in the scope of its transmission planning efforts. In its recently established Multi-Value Project (MVP) transmission planning process and associated cost-allocation methodology, MISO estimates a wide range of benefits for portfolios of projects that meet the MVP criteria.²² In addition, MISO also stressed that the MVP portfolio provides a number of difficult-to-estimate benefits, such as enhanced generation flexibility, increased system robustness, and decreased natural gas price risk.²³ MISO is also in the process of further expanding the scope of its economic valuation process. For example, in the currently-ongoing Manitoba Hydro Wind Synergy Study,²⁴ MISO has estimated benefits related to production cost savings, load cost savings, ancillary service cost savings, wind generation changes, and thermal plant cycling reduction. In addition, MISO noted (but did not estimate) capacity benefits, potential operating reserve benefits (new reserve resources), and storage and energy benefits of

²⁰ *Id.*, p. 37.

²¹ SPP, 2012.

²² MISO, 2011, pp. 25-44.

²³ *Id.*, pp. 53-63.

²⁴ MISO, 2013.

the most flexible new hydro generation. These benefits are evaluated further through sensitivity analyses and risk assessment.

While perhaps less directly comparable to ERCOT, California modified its transmission review process to consider a broad range of transmission-related benefits, recognizing that additional transmission would have significantly mitigated the costs incurred during the California power crisis. Accordingly, the CAISO created its transmission economic assessment methodology (TEAM) to “establish a standard methodology for assessing the economic benefit of major transmission upgrades that can be used by California regulatory and operating agencies and market participants.”²⁵ The TEAM process, at that time, significantly expanded the scope of CAISO transmission planning to include benefits from the increased competition, risk mitigation capability of transmission infrastructure, and the ability to import lower-cost energy and capacity from other regions.²⁶

The TEAM approach specifically recognized that:

[A] significant portion of the economic value of a transmission upgrade is realized when unexpected or unusual situations occur. Such situations may include high load growth, high gas prices, or wet or dry hydrological years. The ‘expected value’ of a transmission upgrade should be based on both the usual or expected conditions as well as on the unusual but plausible situations. A transmission investment can be viewed as a type of insurance policy against extreme events. Providing the additional capacity incurs a capital and operating cost, but the benefit is that the impact of extreme events is reduced or eliminated.²⁷

While the full scope of benefits analysis made possible by the TEAM approach is not applied in the evaluation of all economic transmission projects,²⁸ the California Public Utilities Commission (CPUC) adopted the broad scope of transmission benefits that can be considered through the TEAM approach. Specifically applying the approach, the CPUC approved the Palo Verde-Devers No. 2 (PVD2) transmission project, recognizing transmission benefits including:

- Production cost savings and reduced energy prices from both a societal (*i.e.*, economy-wide) and customer perspective;
- Mitigation of market power;
- Insurance value for high-impact, low-probability events;

²⁵ CAISO TEAM Report, 2004.

²⁶ CAISO PVD2 Report, 2005.

²⁷ CAISO TEAM Report, 2004, p. ES-10.

²⁸ For example, in the CAISO’s most recent transmission planning process the evaluated economic benefits were limited to production cost savings, reduced generating capacity needs, and changes to transmission losses. See CAISO. 2013. Chapter 5 and pp. 301-3.

- Capacity benefits due to reduced generation investment costs;
- Operational benefits (such as reduced reliability-must-run costs and providing the system operator with more options for responding to transmission and generation outages);
- Reduced transmission losses;
- Facilitation of the retirement of aging power plants;
- Encouraging fuel diversity;
- Improved reserve sharing; and
- Increased voltage support.

In the CPUC’s decision for the PVD2 project, the regulator drew additional attention to some of the benefits for which specific values were not measured. The CPUC noted: “discussion of these potential additional benefits...is useful in extending our attention beyond the limits of the quantitative analysis. We consider these factors in our consideration of [the project’s] economic value, even though their potential benefits have not been measured.”²⁹ The importance of these and other transmission-related benefits of transmission investments have also been discussed in a report sponsored by the California Energy Commission.³⁰

Other states have also recognized that transmission projects can provide a broad range of benefits. For example, the Wisconsin Public Service Commission approved in June 2008 its first “economic” transmission line, the Paddock-Rockdale project. That project was approved based on both estimated and qualitatively-discussed economic benefits (for seven alternative future scenarios) that included: (1) adjusted production cost savings; (2) energy and capacity cost savings from reduced transmission losses; (3) reduced power purchase costs due to increased competition; (4) reliability and system failure insurance benefits; (5) long-term resource cost advantages; (6) lower reserve margin requirements; and (7) benefits from the increased availability of financial transmission rights (FTRs).³¹

In contrast to these developments, however, the three northeastern system operators (i.e., NYISO, ISO-NE, and PJM),³² like ERCOT, still continue to plan their transmission system primarily for reliability needs and they are using only traditionally-estimated production cost savings to screen for new “economic” or “market efficiency” transmission projects.

The range of economic benefits considered by other Texas and U.S. system operators is summarized in Table 5. Additional transmission-related benefits may be considered within

²⁹ CPUC *Opinion*, 2007, p. 50.

³⁰ Budhraj et al., 2008.

³¹ ATC (2007).

³² New York Independent System Operator, Independent System Operator of New England, and PJM Interconnection.

individual utilities’ integrated resource planning (IRP) processes and will depend on state regulatory requirements.

Table 5
Benefits Considered in Planning Processes of Other Regional System Operators

System Operator Planning Process	Benefits Estimated	Other Benefits Considered (without necessarily estimating their value)
CAISO TEAM (as applied to PVD2)	<ul style="list-style-type: none"> • Production cost savings and reduced energy prices from both a societal and customer perspective • Mitigation of market power • Insurance value for high-impact low-probability events • Capacity benefits due to reduced generation investment costs • Operational benefits (RMR) • Reduced transmission losses • Emissions benefits 	<ul style="list-style-type: none"> • Facilitation of the retirement of aging power plants • Encouraging fuel diversity • Improved reserve sharing • Increased voltage support
SPP ITP Analysis	<ul style="list-style-type: none"> • Production cost savings • Reduced transmission losses • Wind revenue impacts • Natural gas market benefits • Reliability benefits • Economic stimulus benefits of transmission and wind generation construction 	<ul style="list-style-type: none"> • Enabling future markets • Storm hardening • Improving operating practices/maintenance schedules • Lowering reliability margins • Improving dynamic performance and grid stability during extreme events • Societal economic benefits
Additional benefits recommended by SPP’s Metrics Task Force	<ul style="list-style-type: none"> • Reduced energy losses • Reduced transmission outage costs • Reduced cost of extreme events • Value of reduced planning reserve margins or reduced loss of load probability • Increased wheeling through and out revenues • Value of facilitating public policy goals 	<ul style="list-style-type: none"> • Mitigation of weather uncertainty • Mitigation of renewable generation uncertainty • Reduced cycling of baseload plants • Increased ability to hedge congestion costs • Increased competition and liquidity
MISO MVP Analysis	<ul style="list-style-type: none"> • Production cost savings • Reduced operating reserve needs • Reduced planning reserve needs • Reduced transmission losses • Reduced renewable generation investment costs • Reduced future transmission investment costs 	<ul style="list-style-type: none"> • Enhanced generation policy flexibility • Increased system robustness • Decreased natural gas price risk • Decreased CO₂ emissions output • Decreased wind generation volatility • Increased local investment and job creation
NYISO CARIS	<ul style="list-style-type: none"> • Reliability benefits • Production cost savings 	<ul style="list-style-type: none"> • Emissions costs • Load and generator payments • Installed capacity costs • Transmission Congestion Contract value
PJM RTEP	<ul style="list-style-type: none"> • Reliability benefits • Production cost savings 	<ul style="list-style-type: none"> • Public policy benefits
ISO-NE RSP	<ul style="list-style-type: none"> • Reliability benefits • Net reduction in total production costs 	<ul style="list-style-type: none"> • Public policy benefits

B. A “CHECKLIST” OF POTENTIAL SOCIETAL BENEFITS OF TRANSMISSION INVESTMENTS FOR ERCOT

Based on the industry experience summarized above and our own experience of working with transmission developers and system operators, we assembled a comprehensive catalogue of potential economic benefits that transmission investments can provide. This “checklist of

economic benefits” is summarized in Table 6 and presented in more detail in Appendix B. It shows the production cost savings traditionally estimated as well as additional categories of benefits that often are not evaluated or even considered. Appendix B also provides a more technical discussion of the metrics and experience (including a more detailed discussion of “other project-specific benefits”) with analytical techniques from other regions that can also be applied to estimate the value of these benefits.

Although many of these benefits have not been traditionally considered or estimated by ERCOT and other system operators, this range of benefits represents the starting point for improving ERCOT’s economic planning process in an effort to more fully estimate the economic benefits of transmission investments. As noted earlier, because the benefits of transmission investments are measured in large part as a reduction in system-wide costs, a failure to consider the full economic benefits of transmission investments is equivalent to understating the potentially very costly outcomes that market participants would be exposed to in the absence of the investments.

We provided ERCOT with this “checklist” and a draft of Appendix B to discuss which of these additional economic benefit metrics are most applicable to the ERCOT region and to identify which of these metrics ERCOT could develop and incorporate in its transmission planning efforts over time. As noted during our June 3, 2013 presentation to ERCOT stakeholders, this checklist of potential benefits does not necessarily mean that every category of benefit would increase the value of all transmission projects. Rather, some of these benefit categories may yield negative values for certain projects, thus representing a net increase in societal costs.

Table 6
Summary Table of Potential Economic Benefits

Benefit Category	Transmission Benefit
Traditional Production Cost Savings	Production cost savings as currently estimated, including impact of planned and forced generation outages
1. Additional Production Cost Savings	a. Reduced transmission energy losses
	b. Reduced congestion due to transmission outages
	c. Mitigation of extreme events and system contingencies
	d. Mitigation of weather and load uncertainty
	e. Reduced cost due to imperfect foresight of real-time system conditions
	f. Reduced cost of cycling power plants
	g. Reduced amounts and costs of operating reserves and other ancillary services
	h. Mitigation of reliability-must-run (RMR) conditions
2. Reliability and Resource Adequacy Benefits	a. Avoided/deferred reliability projects
	b. Reduced loss of load probability <u>or</u>
	c. Reduced planning reserve margin
3. Generation Investment Cost Savings	a. Generation investment cost benefits from reduced peak energy losses
	b. Deferred generation investments
	c. Access to lower-cost new generation resources
4. Market Benefits	a. Increased competition
	b. Increased market liquidity
5. Environmental Benefits	a. Reduced emissions of air pollutants
	b. Improved utilization of transmission corridors
6. Public Policy Benefits	Reduced cost of facilitating public policy goals
7. Employment and Economic Development Benefits	Increased employment and economic activity; Increased tax revenues
8. Other Project-Specific Benefits	Examples: storm hardening, increased load serving capability, synergies with future transmission projects, increased fuel diversity and resource planning flexibility, increased wheeling revenues, increased transmission rights and customer congestion-hedging value, and HVDC operational benefits

C. RECOMMENDATIONS CONCERNING BENEFIT METRICS

We reviewed the above checklist of potential metrics with ERCOT staff, assessed their applicability and relative importance within ERCOT, and identified the most readily implementable metrics that could be added by ERCOT in the near-term to improve its current economic modeling practices. We also identified promising benefit metrics that will require the development of additional modeling tools and analytical capabilities before implementation is possible. In parallel, ERCOT has begun to develop case studies that apply some of the identified approaches and metrics to gain familiarity with the modeling and analytical efforts necessary to build the “tool kits” that can be used to evaluate proposed economic transmission projects in the future. Our recommendations are summarized in Table 7 and are discussed in more detail further below. These recommendations reflect a societal perspective of transmission-related benefits and costs—as opposed to solely relying on a customer perspective that may omit benefits or costs imposed on other market participants—as required by the PUCT.³³

Based on our review of ERCOT’s modeling practices and capabilities, we have differentiated our recommendations in terms of near-term and longer-term implementation of improvements to the existing benefit metrics and the implementation of additional benefit metrics. As Table 7 summarized, some additional metrics can be integrated into the transmission planning process such that they are evaluated routinely for each project or group of projects. Others would require periodic studies to develop and update typical multipliers that could then be applied to the evaluation of individual projects. As Table 7 also shows, we recommend a set of benefit metrics that would be developed on a case-by-case basis as projects with likely yield types of benefits are evaluated in the future. We also recommend that ERCOT qualitatively consider the remaining benefit metrics. As transmission projects with likely significant amounts of those specific benefits are evaluated in the future, it may be warranted to develop quantitative tools to estimate the monetary value of these benefits.

³³ The Public Utility Commission of Texas (PUCT) requires that transmission projects be evaluated from a societal perspective, explicitly rejecting the use of a consumer impact or generator revenue reduction perspective for the evaluation of economic transmission projects in ERCOT. See PUCT Order, 2012.

The PUCT Order refers to societal benefits as “levelized annual savings in system production costs resulting from the project,” consistent with the current scope of ERCOT’s economic benefit metrics (*id.*, pp. 15 and 18). However, the PUCT also concluded that “indirect benefits and cost” (*id.*, p. 32) associated with a project—as also contemplated in ERCOT Nodal Protocols, Section 3.11.2(5)—should be considered as well. A discussion of the difference between applying a societal and consumer perspective is included as Appendix C.

Table 7
Recommended Additional Benefit Metrics for Near- and Longer-Term Implementation

Checklist of Potential Economic Benefits of Transmission		Already Used	Recommended for Near-Term Implementation	Recommended for Longer-Term
1. Traditional Production Cost Savings <i>(as currently considered by ERCOT)</i>		✓	Improve	
1a – 1i. Additional Production Cost Savings				
a.	Impact of generation unit outages and designations for ancillary services		✓	
b.	Reduced transmission energy losses		✓	
c.	Reduced congestion due to transmission outages		✓ (multiplier)	
d.	Mitigation of extreme events, system contingencies			✓
e.	Mitigation of weather and load uncertainty		✓ (multiplier)	
f.	Reduced costs due to imperfect foresight of real-time conditions			✓
g.	Reduced cost of cycling power plants		✓	
h.	Reduced amounts and costs of ancillary services			✓
i.	Mitigation of RMR conditions			✓
2. Reliability and Resource Adequacy Benefits				
a.	Avoided or deferred reliability projects <i>(as already considered by ERCOT)</i>	✓	Improve	
b.	Reduced loss of load probability, or:			✓
c.	Reduced planning reserve margin			✓
3. Generation Investment Cost Savings				
a.	Generation investment cost benefits from reduced peak energy losses		✓	
b.	Deferred generation capacity investments		Case by case	✓
c.	Access to lower-cost generation		Case by case	✓
4. Market Benefits				
a.	Increased competition			
b.	Increased market liquidity			
5. Environmental Benefits				
a.	Reduced emissions of air pollutants		✓	
b.	Improved utilization of transmission corridors		Qualitative	✓
6. Public Policy Benefits				
a.	Reduced cost of facilitating public policy goals			
7. Employment and Economic Stimulus Benefits				
a.	Increased employment and economic activity; increased tax revenue			
8. Other Project-Specific Benefits				
such as:	Storm hardening, load serving capability, synergies with future transmission projects, fuel diversity and resource planning flexibility, wheeling revenues, transmission rights and customer congestion-hedging value, HVDC operational benefits		Case-by-case	Synergies with future T; fuel and planning flexibility

1. Recommendations for Near-Term Implementation

We offer the following recommendation for the near-term implementation of improved and additional benefit metrics for further consideration by ERCOT. Appendix B provides additional guidance for each of the discussed benefit metrics.

- *Improve traditional production cost savings metric (#1).* As discussed in more detail in the next section of this report, we recommend that ERCOT expand the time horizon of estimating production cost savings beyond an economic project's first year of operations.
- *Impact of generation unit outages and designations for ancillary services (#1a).* We recommend that ERCOT add the simulation of forced generating unit outages to its long-term planning simulations.³⁴ To ensure consistency across Base and Change cases, the draw of forced unit outage should be held constant. ERCOT should also analyze and reflect in its market simulations the extent to which generating units are dedicated to provide ancillary services (and are thus not available for congestion management).
- *Reduced transmission energy losses (#1b).* We recommend that ERCOT estimate the extent to which transmission investments reduce the quantity and cost of supplying transmission losses by either: (i) simulating changes in transmission losses in PROMOD or UPLAN; (ii) running power flow models to estimate changes in transmission losses for the system peak and a selection of other hours; or (iii) utilizing marginal loss charges (from production cost simulations with constant loss approximation).³⁵ Due to the potentially significant additional effort, this benefit may be evaluated for a portfolio of promising economic projects rather than for each simulation of each project.
- *Reduced congestion during transmission outages (#1c).* We recommend that ERCOT study the extent to which transmission outages increase congestion and production costs relative to standard market simulations assuming all transmission facilities are available 100% of the time. By analyzing for several economic transmission projects how much consideration of transmission outages would typically increase the production cost savings compared to standard market simulations that do not reflect transmission outages, ERCOT should be able to develop a "multiplier" that can be applied to the results of the standard market simulations.³⁶ The multiplier can be updated over time as more

³⁴ We understand that maintenance outages are already modeled.

³⁵ For a discussion of estimating loss-related production cost savings from the marginal loss results of production cost simulations see SPP, 2012, Section 4.2. See also Pfeifenberger Direct Testimony, 2008. Note that if transmission additions facilitate additional generation from remote generation, total transmission losses may increase, thus representing an increase in loss-related costs.

³⁶ For example, a recent SPP study showed that modeling a subset of transmission outages over a 12-month period increased the production cost savings of a broad portfolio of transmission projects by about 11.3%. See SPP, 2013, Section 7.5.4. See also discussion in Appendix B.

experience is gained with the analysis of how the consideration of transmission outages affects project benefits.

- *Mitigation of weather and load uncertainty (#1e).* We recommend that ERCOT study the extent to which the combination of 10/90, 50/50 and 90/10 ranges of weather and load conditions affects the probability-weighted “expected” production costs savings of new transmission projects compared to the standard market simulations that are based only on normalized peak demand and monthly energy consumption (*i.e.*, 50/50 weather and load conditions).³⁷ For example, as noted by Luminant, simulations performed by ERCOT for normal loads, higher-than-normal loads, and lower-than-normal loads in its evaluation of a Houston Import Project showed a \$45.3 million annual consumer benefit for the Base Case simulation (normal load) compared to a \$57.8 million probability-weighted average of benefits for all three simulated load conditions.³⁸ Note, however, that the ratio was calculated for consumer benefits; it may differ for production cost savings. By analyzing this ratio for several transmission projects or a portfolio of projects, ERCOT should be able to develop a “multiplier” that can be applied to the results of the standard market simulations (reflecting only normal weather and load conditions).
- *Reduced costs of cycling power plants (#1g).* We recommend that ERCOT report in its simulations the cycling frequency of generating plants with high startup and shutdown costs. A recent study of power plants in the Western U.S. found that increased cycling can increase the plants’ maintenance costs and forced outage rates, accelerate heat rate deterioration, and reduce the lifespan of critical equipment and the generating plant overall. The study estimated that the total hot-start costs for a conventional 500 MW coal unit are about \$200/MW per start (with a range between \$160/MW and \$260/MW). The costs associated with equipment damage account for more than 80% of this total.³⁹ We recommend that ERCOT estimate through post-processing of its simulation results the extent to which transmission investments may decrease (or increase) such cycling costs beyond the fuel and variable O&M costs already considered in the simulations.
- *Improve the current estimates of avoided or deferred reliability project costs (#2a).* As discussed in more detail in the next section of this report, we recommend that ERCOT improve its process to estimate the extent to which an economic transmission project can

³⁷ See SPP, 2012, Section 9.6.

³⁸ ERCOT, 2011a, p. 10. The \$57.8 million probability-weighted estimate is calculated based on ERCOT’s simulation results for three load scenarios and Luminant’s estimated probabilities for the same scenarios.

³⁹ See Kumar, *et al.*, 2012. The study is based on a bottom-up analysis of individual maintenance orders and failure events related to cycling operations, combined with a top-down statistical analysis of the relationship between cycling operations and overall maintenance costs. See *Id.* (2011), p. 14. Costs inflated from \$2008 to \$2012. Note that the Intertek-APTECH’s 2012 study prepared for NREL (Kumar, *et al.*, 2012) reported only ‘lower-bound’ estimates to the public.

avoid or defer future reliability projects by estimating this benefit beyond the first year of the economic project's operations. This may show that a reliability project avoided in the first year of an economic project's operations may still be needed in the future (*i.e.*, would only be deferred) while there may be additional reliability projects that are either avoided or deferred after the economic project's first year of operation.

- *Generation investment cost benefits from reduced peak energy losses (#3a).* We recommend that ERCOT calculate the extent to which economic projects (or portfolios of economic projects) reduce resource adequacy requirements by reducing transmission losses during annual system peaks. For example, at a target planning reserve margin of 15%, a 100 MW reduction in on-peak losses (*e.g.*, as estimated through power flow simulations) would reduce installed generation needs by 115 MW. The societal value of this benefit can be determined by multiplying the reduced generation need by the annualized net cost of new generation (net of simulated annual energy and ancillary service margins).
- *Deferred generation investments and access to lower-cost generation (#3b, #3c).* We recommend that ERCOT evaluate the potential benefits of economic transmission projects on a case-by-case basis. For example, a transmission project may allow moving a needed generating plant from a high-cost location (*e.g.*, in a metropolitan area) to a location with significantly lower costs (*e.g.*, a less densely populated area with a lower-cost site, lower environmental compliance costs, lower infrastructure costs, and lower fuel and O&M costs).
- *Reduced emissions of air pollutants (#5a).* We recommend that ERCOT confirm that emission costs are reflected for pollutants with a market price for emissions. We also recommend that the reduced emissions without market prices (such as particulates and mercury) be quantified and its societal value be considered at least qualitatively. For long-term scenario-based planning and to assess the risk-mitigation aspect of transmission investments, we also recommend that ERCOT consider simulating futures with higher emission costs, including the possibility of climate legislation with carbon pricing.
- *Improved utilization of transmission corridors (#5b).* We recommend that, in the near-term, ERCOT consider at least qualitatively the extent to which alternative transmission options (both alternative reliability projects and economic projects) may be more effective in utilizing existing rights-of-way or minimizing the long-term need for additional rights-of-way. For example, upsizing a new transmission line today can avoid the need for a second line in the future, thus reducing the total long-term need for right-of-way.

- *Other project-specific benefits (#8).* We recommend that ERCOT consider and develop benefit metrics on a case-by-case basis to the extent to which a transmission option may provide: (a) storm hardening benefits; (b) increased local load-serving capability (thereby supporting economic development); (c) synergies with future transmission projects (e.g., allowing for a low-cost option for future upgrades, such as the completion of a 345kV loop around Austin); (d) increased fuel diversity and resource planning flexibility (e.g., by providing lower-cost outcomes in more challenging future scenarios); (e) increased wheeling revenues (e.g., if transmission projects are considered that would support increased exports of renewable energy); (f) increased transmission-rights and congestion-hedging opportunities; and (g) unique system operations benefits (e.g., through HVDC transmission technology).

2. Recommendations for Longer-Term Implementation

In addition to the above recommendation for near-term implementation, and for further consideration by ERCOT, we offer the following recommendations for the longer-term to improve the scope of benefit-cost analysis and capture the value of additional benefits (or costs). Appendix B also provides additional guidance for each of the discussed benefit metrics.

- *Mitigation of extreme events and system contingencies (#1d).* We recommend that ERCOT develop a data set of extreme but realistic events and system contingencies. Simulating such outcomes for future years will allow ERCOT to estimate the extent to which transmission expansion reduces the costs associated with these events and contingencies. The set of events and contingencies may be based on historical data for major storms, significant weather and drought events (such as summer 2011), or unusual but possible multiple generation outages (e.g., due to regulatory actions or single-source failure of fuel supply). The data set would also require the season and duration of the events, and an estimate of the probability with which these or similar events might occur in any particular year (e.g., 5%), which can then be applied to the estimated cost reductions. Though some projects may require the definition of specific events and contingencies, a common set of extreme events and contingencies will likely be useful to evaluate a wide range of economic projects (or portfolios of projects).
- *Reduced amounts of ancillary services and reduced congestion due to imperfect foresight (#1f, 1h).* We encourage ERCOT to further develop its modeling of the implications of imperfect foresight of real-time system conditions and intra-hour balancing of supply and demand through ancillary services. Although the current modeling effort (using the KERMIT software) is not focused on the role transmission can play in this context, transmission investment that creates a larger unconstrained, more diversified market can

reduce ancillary services needs and the system-wide costs associated with imperfect foresight.⁴⁰

- *Mitigation of RMR conditions (#1i).* Production cost simulations typically do not capture the extent to which transmission investment can reduce the need for out-of-market reliability-must-run commitment (e.g., due to voltage constraints or second contingency conditions). To the extent that significant costs for such out-of-market RMR commitments are incurred in the future as load grows within import constrained regions, we recommend that the extent to which transmission investment avoid RMR commitments and associated costs be analyzed and simulated. This may require manually adjusting must-run generation levels in production cost simulations with and without the contemplated upgrade.
- *Reduced loss of load probability or reduced planning reserve margin (#2b, 2c).* Even if not targeted to address identified reliability needs, transmission investments can reduce the frequency and severity of load curtailments, thus improving physical reliability of the system in addition to production cost savings.⁴¹ This provides direct societal value in the form of either reducing the MWh of lost load or by allowing ERCOT to reduce its target reserve margin. To assess the extent to which transmission investments can provide these benefits, we recommend that ERCOT further explore this benefit and develop corresponding metrics. ERCOT may be able to do so by utilizing the results of its zonal reliability analysis or by using PROMOD in reliability simulation mode.
- *Deferred generation investments and access to lower-cost generation (#3b, 3c).* We recommended that ERCOT explore this benefit in the near-term on a case-by-case basis, as discussed above. In addition to this case-by-case approach, we recommend that ERCOT further study the extent to which generation costs (investment costs, other fixed costs, or operating costs) may differ across locations and sites. Improved data on such locational cost differences will also be helpful in the scenario-based resource expansion analysis of ERCOT's future long-term planning efforts.
- *Improved utilization of transmission corridors (#5b).* Scarcity of transmission rights-of-way and environmental impacts of establishing new rights-of-way can be one of the most important determinants of the economic desirability and political feasibility of

⁴⁰ From a long-term planning perspective, any additional buildout of intermittent renewable resources may also increase ancillary service needs and system costs related to imperfect foresight. Transmission expansion may reduce ancillary service needs and system costs related to imperfect foresight all else being equal. However, since all else is not equal for long-term planning purposes, these impacts need to be taken into account in scenarios developed for long-term planning purposes.

⁴¹ Transmission may achieve such physical reliability benefits, for example, by reducing higher loss of load probability in import-constrained load pockets or by increasing interconnections with neighboring regions.

transmission expansion. In addition to considering transmission corridor utilization on a case-by-case basis in the near term as discussed above, we thus recommend that ERCOT develop a more systematic approach to consider this factor in its long-term planning processes. As noted earlier, upsizing near-term projects or creating options to upsize lines in the future may yield significantly improved utilization of transmission corridors in the long-term.

- *Synergies with future transmission projects (#8).*⁴² In addition to considering this benefit of some transmission options on a case-by-case basis in the near term, we also recommend that ERCOT develop a framework to more systematically capture this aspect of transmission planning (e.g., how to modify near-term transmission projects that create low-cost options in the long-term).
- *Increased fuel diversity and resource planning flexibility (#8).*⁴³ We also recommend that ERCOT develop a framework to more systematically capture the fuel diversity and resource planning flexibility benefit of transmission investments. It may be possible to study different scenarios and sensitivities of generation expansion and retirement cases to better understand the value of transmission to mitigate future costs associated with currently unexpected shifts in relative fuel prices, technology costs, and unexpected retirements or resource needs.

As noted, we also recommend that ERCOT qualitatively consider the remaining benefit metrics listed in Table 7. As transmission projects with likely significant amounts of those specific benefits are evaluated in the future, it may be warranted to develop quantitative tools to estimate the monetary value of these benefits. Appendix B provides some additional guidance for those metrics.

⁴² See Item 8c in Appendix B, page B-5 and subsequent discussion.

⁴³ See Item 8d in Appendix B, page B-5 and subsequent discussion.

VI.IMPROVEMENTS FOR THE OVERALL TRANSMISSION PLANNING PROCESS AND DECISION CRITERIA

Based on our review of ERCOT’s long-term transmission planning process and the findings summarized above, we developed the following recommendations for further consideration by ERCOT and its stakeholders. These recommendations, summarized in Table 8, are focused on enhancing ERCOT’s planning process for evaluating the economic benefits and costs of transmission investments from a societal perspective, as required by the PUCT.

Table 8

Recommendations for Enhancing ERCOT’s Transmission Planning Process	
1:	Link Near- and Long-term Planning Processes
2:	Evaluate Economic Projects based on their NPV or a Comparison of Levelized Benefits and Costs
3:	Expand Benefits (and Costs) Considered and Quantified
4:	Identify Key Uncertainties and Improve Development and Use of Scenarios and Sensitivities
5:	Enhance Economic Project and Benefits/Costs Identification Process

The initial draft of these recommendations was presented to stakeholders publicly at the June 3, 2013 ERCOT Regional Planning Group meeting. The slides used to present our draft recommendations (“Recommendations for Enhancing ERCOT’s Long-Term Transmission Planning Process”) are provided in Appendix E. The remainder of this section first summarizes stakeholder comments on our draft recommendations, then presents our final recommendations on each of the five topics summarized in Table 8. We already discussed Recommendation No. 3 (additional benefit metrics) in Section V of this report but, for convenience, we will further summarize our recommendations below.

A. STAKEHOLDER COMMENTS ON DRAFT RECOMMENDATIONS

We received eleven sets of stakeholder comments in response to our draft recommendations presented at the June 3, 2013 stakeholder meeting. They included (listed in alphabetical order) comments from American Electric Power (AEP), Electric Power Engineers, an ERCOT staff member (not previously involved in this effort), Lower Colorado River Authority (LCRA), Lone Star Transmission, Luminant, Oncor, a PUCT staff member, Save Our Scenic Hill Country Environment (SOSCHE), South Texas Electric Cooperative, and Texas Industrial Electricity Consumers (TIEC).

The comments received covered a diverse set of opinions, ranging from broad support for the presented recommendations, to a view that new transmission projects should only be planned to maintain reliability and low costs to consumers (as opposed to considering societal benefits), to concerns about the value or process of scenario-based planning, and the position that benefits more than a few years in the future are highly speculative and should not be considered. In general, however, the majority of stakeholders support: (a) linking the long-term planning effort to the near-term RTP process for the evaluation of economic projects; (b) adding at least a subset of the potential additional benefit metrics (after considering additional stakeholder input); and (c) utilizing NPV concepts in comparing costs and benefits (although differences of opinions exist about the discount rates that should be applied to long-term benefits and costs)

To provide the full context of these comments, they are summarized for individual parties as follows:

- Largely supports recommendations, which should be implemented in near term. Single economic model should be used for near-term and long-term. Supports additional benefit metrics and improvement to how costs and benefits are compared. Additional production cost savings recommendations 1a through 1g should be implemented as soon as possible. Tentatively supports implementation of metrics 2a and 3a, 2b, or 2c, and 8b and 8c as soon as possible. Some of the others may be more controversial or could be delayed for further consideration.
- Reach consensus on and adopt the most promising and pragmatic recommendations; highly unlikely transmission improvements will lose value and benefits, but assigning dollar value to long-term benefits is difficult given substantial uncertainties of projecting benefits 40 years into the future; production cost modeling not yet sufficiently accurate; use of other benefits that may or may not be quantifiable would be a good improvement; such benefits may be avoiding cost of smaller projects in the future and reducing cost of planned transmission outages; more explanation and tool development is needed for other metrics.
- Transmission should be planned to maintain reliability and lower costs to consumers; STEC is highly skeptical of benefits that extend more than a few years into the future; benefits that do not directly benefit consumers should not be counted.
- Transmission should be built only to maintain reliability and lower costs to consumers. Benefits under speculative scenarios should be heavily discounted. Purely speculative benefits should not be included at all. Benefits should be counted only if they directly reduce customer costs. Economic stimulus value should not be counted. Net present value approaches should discount benefits more than costs. Projects should be evaluated to include option value, including option to delay investment. Beneficial projects should not be grouped with uneconomic projects.

- Supports linking long-term planning to RTP process and use of long-term planning results to evaluate economic projects in RTP. Groups of benefits not currently considered should be considered in stakeholder process through phased approach, first considering additional production cost savings, then reliability and resource adequacy benefits, followed by environmental and other benefits. Focus only on benefits most relevant/applicable to ERCOT.
- Benefits not considered in ERCOT planning process are very significant, including metrics such as cost of losses, benefit of reduced cycling of generators, deferred cost of reliability, *etc.* ERCOT should explain how long-term planning results are used for evaluating nearer-term projects.
- Agree that long-term and RTP processes should be linked so that long-term planning results can be used in evaluating economic projects in RTP; supports scenario and sensitivity assessment to demonstrate project purpose, need and overall value; will assist TSP during implementation phase. To support developing/evaluating large transmission projects, ERCOT/TSP workshops should be used more frequently than once a month.
- Generally supportive of recommendations on improvements and modeling practices. Levelized benefit-cost comparison and using long-term planning results in RTP process would provide the most immediate value. Improving use of scenarios and sensitivities will help develop more robust transmission plans. Until these recommendations are implemented, put on hold and possibly revisit new benefit metrics that will require development of additional data and tools.
- Long-term projections beyond 10 years are of limited use due to uncertainty about the future. Long-term cost-benefit analyses need to recognize and quantify that benefits are more driven by uncertainties about the future than costs.
- Accuracy of scenarios decline and discounted as planning cases move further into the future; sufficient number of scenarios should also include possible impact of technological change; high-probability and low-probability scenarios should be weighted differently.
- Make explicit that ERCOT's generation modeling does not currently include back-up and reliability costs for intermittent resources, particularly wind generation. Address metrics that could address concerns about transmission, such as percentage of existing right-of-way that can be utilized.

Our finalized recommendations are discussed in detail below.

B. LINK NEAR-TERM AND LONG-TERM PLANNING PROCESSES

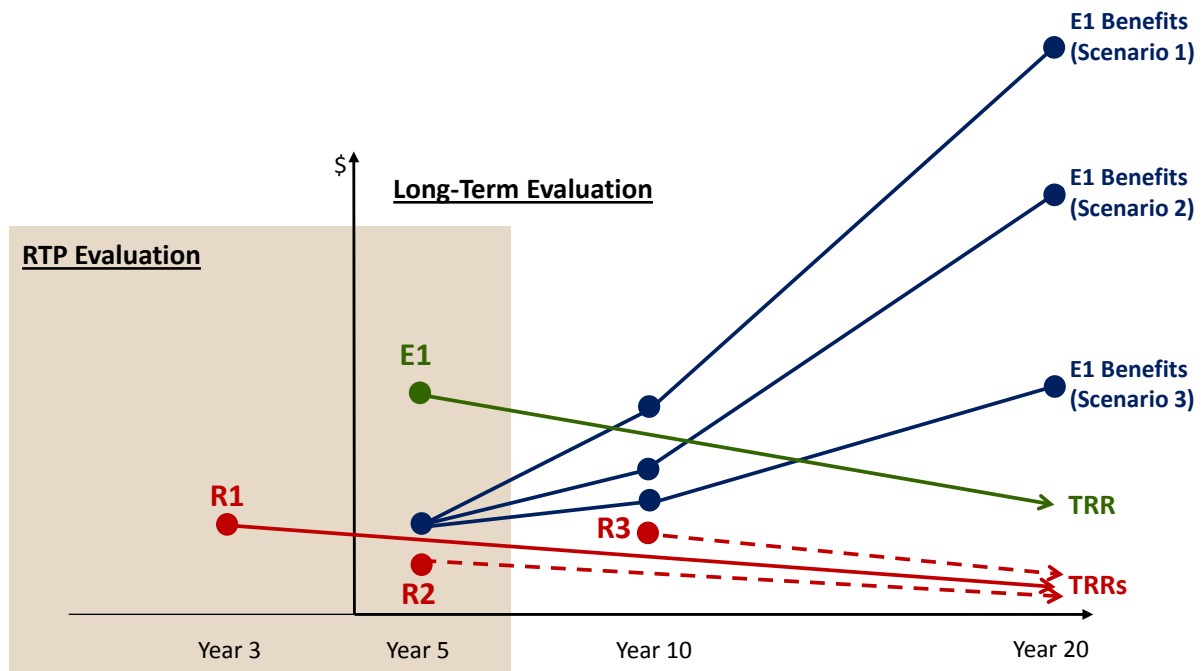
We recommend that ERCOT more systematically link its long-term (LTSA) transmission planning processes and the near-term (RTP) planning process. Such linkage would increase the consistency in modeling assumptions and results between the studies performed for two separate planning horizons. It would also avoid duplicate modeling efforts, and allow the effective use of results from long-term studies to inform near-term planning efforts. Accordingly, we also recommend that ERCOT integrate its near- and long-term modeling teams and use a single economic model with consistent set of input assumptions for both the near-term and long-term analyses. Such integration would help improve the quality, consistency, and efficiency of the workflow and enable a more integrated transmission planning process going forward.

Specifically, we recommend that ERCOT use the results of its long-term studies in the identification and evaluation of economic transmission projects within its RTP process. Transmission needs would continue to be determined and approved primarily through the RTP process, with most projects considered to be built over the ensuing 5 to 6 years of the RTP time frame. However, the monetary value of the benefits and costs of economic projects that could be developed within that 5 to 6 year time frame would be estimated based on results from both the near-term and long-term analyses. Utilizing information about the benefits and costs of an economic project over a significant portion of its useful life would help determine the actual economic value of a project, which in turn would help assess more accurately the tradeoffs between incremental reliability upgrades and economic project alternatives.

Figure 2 illustrates our recommendation of linking the near- and the long-term planning processes. This hypothetical example compares annual dollar values of benefits and costs of projects (y-axis) over the time frame of both the RTP and long-term planning processes (x-axis). The RTP process (over the first 5–6 years) is highlighted by the shaded block on the left. In this example, the RTP process identified two reliability upgrades, “R1” and “R2,” which would be needed in years 3 and 5, respectively. The red dots and lines corresponding to R1 and R2 represent the regulated annual costs of the reliability projects (in terms of annual transmission revenue requirements or “TRRs”). These annual costs decline as the assets are depreciated over their useful life (typically estimated at 40 to 50 years).

Figure 2 also shows that an economic transmission project, “E1,” proposed to be installed in year 5, could replace R2 while also providing additional economic benefits. In this example, if E1 were built, then R2 would not be needed. The green dot and line that correspond to E1 illustrate that the annual costs of E1 are significantly higher than the annual costs of R2. However, in addition to avoiding the construction of R2, the development of E1 would also offer incremental savings above those associated with R2 as indicated by the three trajectories of blue dots and lines. The three blue lines depict the project’s total annual savings under three alternative future scenarios.

Figure 2
Linking Near-Term and Long-Term Evaluation of Economic Projects



ERCOT's current evaluation process focuses on only the first year of the projects' costs and benefits. Accordingly, ERCOT calculates the E1's first-year revenue requirements net of the avoided first-year costs of R2, and then compares these net costs against the first-year annual production cost savings of Project E1. With such a comparison and threshold, as illustrated, the economic project E1 would be rejected because its first-year costs net of avoided R2 costs exceed production cost savings in that year.

The three blue lines show that the E1's annual production cost savings would grow over time, at different rates based on the alternative future scenarios considered. Such growth is typical due to the combined effects of load growth and increasing fuel prices. It is also possible that the production cost savings would decrease over time if load and fuel prices decrease or if the avoided future reliability projects offer similar levels of production cost savings as E1 does. Therefore, the three different trajectories of annual benefits depend on the assumptions used in depicting the alternative future scenarios.

According to the example shown in Figure 2, it is assumed that if E1 were built in year 5, it would also avoid another reliability upgrade, "R3," in year 10 (which would likely be identified in the subsequent RTP evaluations in absence of E1). Thus, an evaluation of whether the economic project E1 should be pursued requires estimates of such avoided reliability project costs that would be offered by E1 over time.

In Figure 2, we only show the hypothetical annual production cost savings and the avoided annual cost of reliability upgrades R2 and R3. Nevertheless, as illustrated, while the economic project E1 could not be justified by comparing first-year costs with its limited first-year benefits, the total *value* of the economic project's annual benefits over its useful life, even if discounted for future years, would likely exceed the total project costs. Another way to look at this is that if the system needs are only considered in the RTP process without regard for the longer term time horizon, the total cost to society will be greater. Hence, there is a societal impact if the long-term costs and benefits are not also analyzed when evaluating projects that can be placed into service in the near-term.

As the illustration in Figure 2 shows, the economic project E1 would still undergo evaluation and approval through the RTP process for completion in year 5, but the comparison of its benefits and costs would be informed by the results from the long-term assessment that reaches out 20 years. The scenario-based long-term assessment would also indicate the robustness of the economic project's value under the alternative future scenarios.

Linking the near-term RTP with the long-term process will allow for the costs and benefits over the lifetime of the transmission assets to be considered in the analysis of economic projects in the RTP. We also believe linking long-term evaluation results from ERCOT's long-term planning process to the evaluation of near-term projects in ERCOT's RTP process is consistent with ERCOT protocols and PUCT orders that define transmission benefits as the "estimated levelized annual savings in system production costs" plus any "indirect benefits" other than production cost savings.⁴⁴ As discussed further in the next subsection of our report, determining the "levelized annual" value of transmission benefits requires that the value of transmission benefits is "levelized" over the time period during which the benefits accrue. Considering that transmission assets will produce benefits (however uncertain) over the entire useful life of the assets, this requires the evaluation of benefits from a long-term perspective.

C. EVALUATE ECONOMIC PROJECTS BASED ON THEIR NET PRESENT VALUE (NPV) OR A COMPARISON OF LEVELIZED BENEFITS AND COSTS

The economic benefits of transmission projects and their alternatives accrue over the entire life of the asset. We consequently recommend that the long-term value of costs and benefits be considered in the evaluation of potential economic transmission projects. While decisions about necessary reliability-driven transmission projects can be made based on conditions in the year when the identified reliability need first occurs, decisions about economically-justified projects require the assessment of *economic value*, which at any point in time is defined by the benefits and costs that accrue over the remaining useful life of the investment.

⁴⁴ See PUCT Order, 2012, pp. 15, 18 and 32.

We first discuss this aspect of our recommendations in more detail and then present a case study to illustrate the application of evaluating economic projects through NPV or levelized benefit-cost analyses.

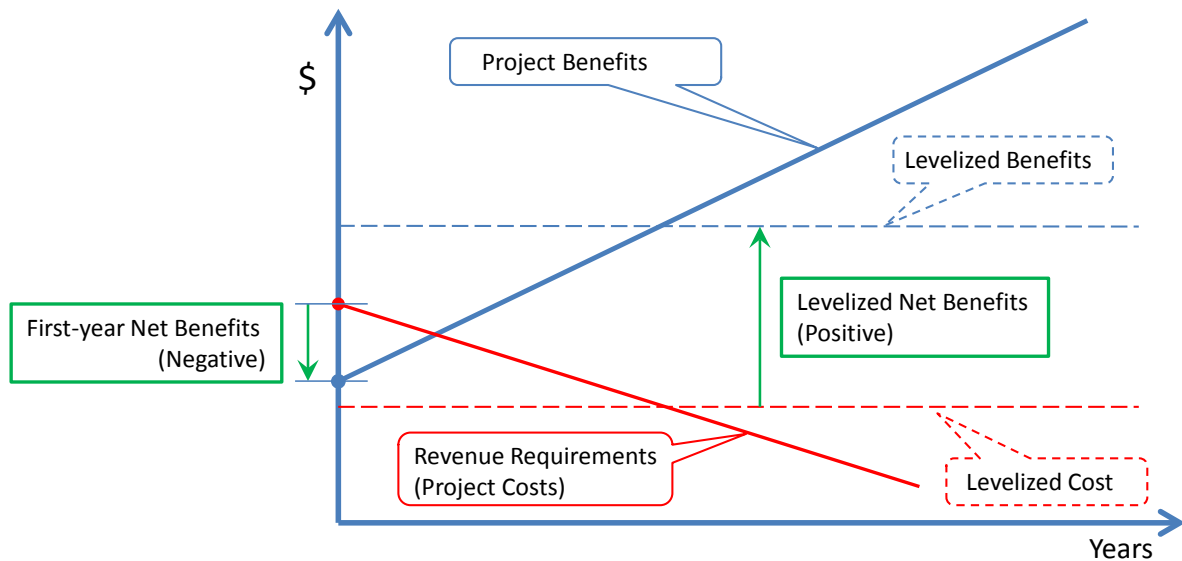
1. Concept of and Recommendations for NVP or Levelized Benefit-Cost Analyses

The current ERCOT practice of evaluating economic projects is typically to perform production simulations for just the first year of the proposed project.⁴⁵ ERCOT then compares the first-year production cost savings against $1/6^{\text{th}}$ of the project's construction costs, net of $1/6^{\text{th}}$ of any avoided reliability project costs in that year. Taking $1/6^{\text{th}}$ of a project's construction cost is approximately equal to the project's regulated cost of service (*i.e.*, its regulated transmission revenue requirement or TRR) in the first year. This approach carries a high risk of rejecting potentially beneficial economic projects for three main reasons:

- a. Production cost savings and other benefits tend to grow over time with increasing load and fuel prices (although this may not be always the case). As a result, the production cost savings for the first year of a project are generally lower than the "levelized" annual benefit that reflects the project's average savings over time. Figure 3 below illustrates how the levelized annual value of long-term benefits can be much larger than the benefits in the first year of a new project. As illustrated, it can easily be the case that first-year benefits are less than first-year costs even though levelized benefits significantly exceed both first-year costs and levelized costs.
- b. The annual cost of transmission investments, reflected in TRRs, decline over time as the assets are depreciated. The first-year TRR of a project, estimated as $1/6^{\text{th}}$ of its construction cost, is approximately 30% higher than the levelized annual value of its TRR over time. Thus, if benefits need to exceed $1/6^{\text{th}}$ of the project's construction cost, then the levelized benefits have to be approximately 30% greater than the project's levelized revenue requirements.
- c. The economic projects may offer benefits beyond production cost savings as discussed before. This likely includes benefits to materialize after the first-year, such as the benefits associated with avoided reliability project costs, which should be considered in the benefit-cost analyses as well.

⁴⁵ ERCOT simulates all years that they have models available for in which the proposed project will be placed in service, although this is generally just for the first year of operation. For example, if a project is projected to be in-service in 2015 and models are available for both 2015 and 2017, then both years will be modeled. However, if the project is proposed to be on-line in 2017, only one year will be modeled, which is generally the case.

Figure 3
Comparing First-Year and Levelized Project Costs and Benefits



For these reasons, we recommend that the costs and benefits associated with proposed transmission projects be compared based on their present values or levelized values. The present value approach compares the present value of a project's long-term benefits to the present value of a project's costs. The present values of benefits and costs are estimated as the sum of annual benefits and annual costs, both increasingly discounted over time to reflect the fact that a dollar spent or saved 10 or 20 years from now is significantly less valuable than a dollar saved or spent today.

As an alternative to comparing the present values of benefits and costs, it is equally suitable to compare the benefits and costs using levelized annual values. This is because the levelized costs and benefits would yield the same present values as the estimated time-varying amounts; therefore, they would lead to the same benefit-to-cost ratios. The NPV-based or levelized benefit and cost comparisons are used by virtually all other system operators and we recommend ERCOT adopt a similar methodology.

To estimate annual benefits over time, the annual values can be interpolated based on specific estimates for a few future study years, such as year 1, year 5, and year 10 (or year 20) and then extrapolated further into the future based on a conservative assumption of how benefits would remain over time. It is important to recognize that the value of transmission investments rarely declines over the long term. The time frame over which the annual benefits and costs are estimated for present value calculations is typically between 20 and 40 years in most of the other planning regions, although some system operators use time horizons as low as 10 years while

others estimate values over the full 50 years of a project's assumed life.⁴⁶ We recommend that ERCOT consider estimating benefits and costs over a time horizon between 20 and 40 years, consistent with the other system operators in Texas and neighboring regions.

We recommend ERCOT use a PUCT-approved weighted average cost of capital (WACC) of the transmission owners to discount estimated future benefits and costs, although some planning regions (such as the MISO) also use a lower "societal" discount rate. Using a PUCT-approved WACC as a discount rate would appropriately reflect the risks of transmission investments. Using higher or lower rates, or applying different rates to benefits and costs would not properly capture the projects' risks and it would also misrepresent the potential costs imposed on market participants in the absence of the contemplated transmission investment.

Economic projects in most transmission planning regions are required to have benefits in excess of costs that remain above a certain threshold. The higher perceived uncertainties associated with estimated benefits typically are addressed through benefit-cost thresholds in excess of 1.0 (such as 1.25 in most other regions) and the recognition that many transmission-related benefits may not be quantified. ERCOT's approach of comparing the benefits of a project with 1/6th of the project's construction costs (as an estimate of the project's first year of revenue requirements), consistent with the previously-discussed PUCT order, effectively imposes a benefit-to-cost ratio threshold of 1.30 as discussed below.

However, as shown in Figure 3, the first-year TRR of a transmission project is at its highest relative to the rest of the useful life of the project. Under typical ratemaking treatment of transmission costs, a project's first year TRR is approximately 30% higher than the levelized value of these TRRs over the project life that yields the same present value as the actual declining profile of TRRs. Thus, comparing levelized benefits to 1/6th of the project's construction costs is equivalent to a requirement that the benefit-cost ratio of a project exceeds 1.3 from a present value perspective. We do not advise modifying this criterion at this point, but recommend that ERCOT also calculate a project's benefit-cost ratio based on levelized benefits and levelized costs to recognize the extent to which this approach requires that the value of estimated benefits exceed estimated costs.

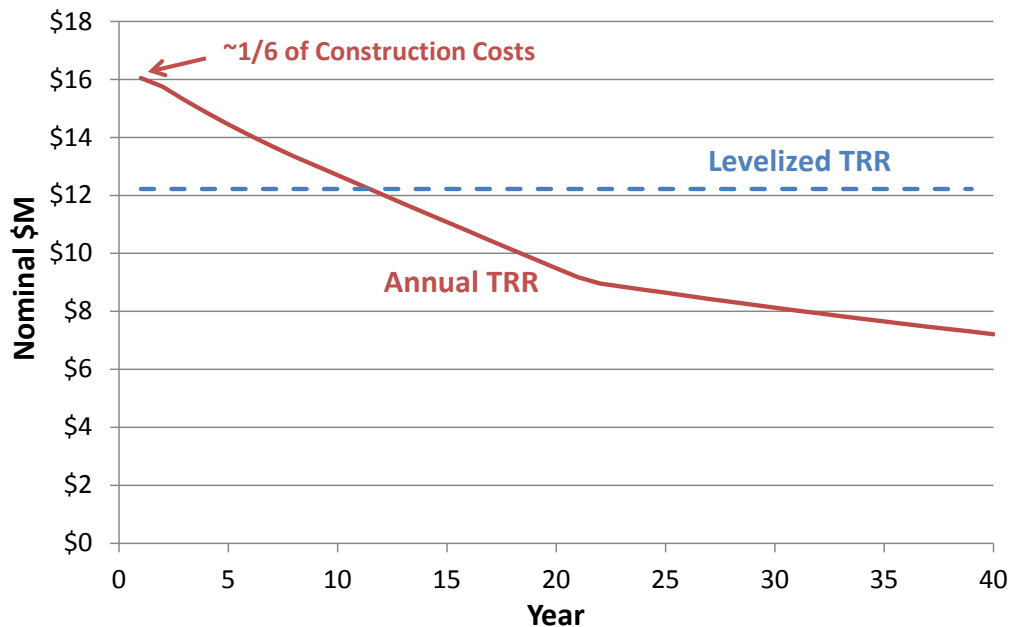
As shown in Figure 4 for a hypothetical \$100 million transmission project, the TRR of a transmission project is at its highest in the first year relative to the rest of the useful life of the project. As a result, the first-year TRR is also higher than the levelized TRR.⁴⁷ As shown, when

⁴⁶ Other transmission planning organizations use the following time horizons to calculate benefit: SPP (which operates a portion of the power grid in Texas) 40 years; MISO (which will soon operate the Entergy portion of the Texas grid) 20 and 40 years; NYISO 10 years; PJM 15 years; ISO-NE 10 years; and CAISO 40 years for upgrades to existing facilities and 50 years for new facilities.

⁴⁷ Under "cost-of-service regulation," the annual cost of transmission is calculated as an asset's TRR, which is determined based on each project's (straight-line) depreciation, return on ratebase, taxes, and operation

applying typical ratemaking treatment of transmission costs, a project's estimated first year TRR is approximately 30% higher than the levelized value of these TRRs over the project life.⁴⁸ Thus, comparing an economic project's levelized benefits to 1/6th of the project's construction costs is equivalent to a requirement that the benefit-cost ratio of a project exceed 1.3 from a present value perspective. We recommend maintaining this approach, recognizing that it imposes a threshold that requires estimated benefits exceed estimated costs by at least 30%.

Figure 4
Transmission Revenue Requirements for Hypothetical \$100 Million Transmission Project



2. Case Study of an NVP and Levelized Benefit-Cost Analysis

To illustrate the application of utilizing net present values or levelized benefits and costs in the evaluation of economic projects, we jointly developed with ERCOT staff a realistic example of an economic project E1 that could be built in 2017 for an estimated cost of \$291 million. As of

and maintenance costs. In this example, the accumulation of the benefit from accelerated tax depreciation (relative to straight-line regulatory depreciation) makes the TRRs decline faster over the initial twenty years of a project.

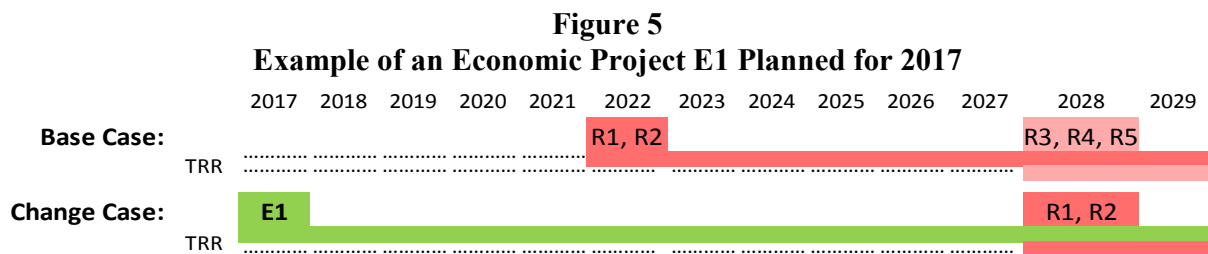
⁴⁸ Estimating the first year revenue requirements using the 1/6th method can result in a value that is 25–40% higher than levelized costs depending on the depreciation, capital structure, taxes, and O&M costs of any particular transmission project. TXU Energy estimated the value to be 25% in a recent PUCT filing concerning the comparison of project costs and benefits in the analysis of economic projects in ERCOT. (TXU Energy, 2013)

2017, the 40-year present value of the economic project's revenue requirement was estimated to be \$465 million.

The timeline of various baseline reliability projects that would need to be built in the Base Case (without the economic project) is shown in the top portion of Figure 5; the timeline of constructing the economic project and the alternative set of reliability projects needed in the Change Case (with the economic project) is shown in the bottom half of Figure 5.

As shown, the Base Case (without the economic project) requires the construction of five baseline reliability projects, two of which will be required in 2022 (R1 and R2) for a cost of \$90 million and another three reliability projects (R3, R4, and R5) that would be required in 2028 for a cost of \$321 million. The figure illustrates that adding these reliability projects in 2022 and 2028 would be associated with additional annual transmission revenue requirements starting in these years and lasting throughout the useful life of these assets. As of 2017, the 40-year present value of the Base Case reliability projects' revenue requirement was estimated to be \$308 million.

Using market simulations, ERCOT staff determined that the addition of the economic project (E) in 2017 in the Change Case would defer reliability projects R1 and R2 for six years to 2028 and avoid the reliability upgrades R3, R4, and R5 completely. As of 2017, the 40-year present value of the Change Case reliability projects' revenue requirement (*i.e.*, only for R1 and R2 built in 2028) was estimated to be \$67 million.



The comparison of Change Case and Base Case costs thus shows that building the economic project in 2017 and incurring \$465 million in present value of TRR is offset by a \$241 million present value in lower TRRs for avoided or deferred reliability projects. These reliability project cost savings in (2017 dollars) are equal to the difference between a 40-year present value of \$308 million for reliability projects in the Base Case and a 40-year present value of \$67 million in the Change Case). As also shown in Figure 5, these avoided and deferred reliability project cost savings are the result of: (1) the avoided annual Base Case costs of R1 and R2 during 2022 through 2027; and (2) having to pay for R1 and R2 while avoiding R3 through R5 starting in 2028. The annual values of these savings (starting in 2022 and increasing in 2028) are shown in Figure 6, in combination with estimated annual production cost savings.

The cost of the economic project net of the reliability project cost savings is thus \$223 million in 2017 present value terms. These net costs will have to be more than offset by other economic benefits of the project, such as production cost savings.

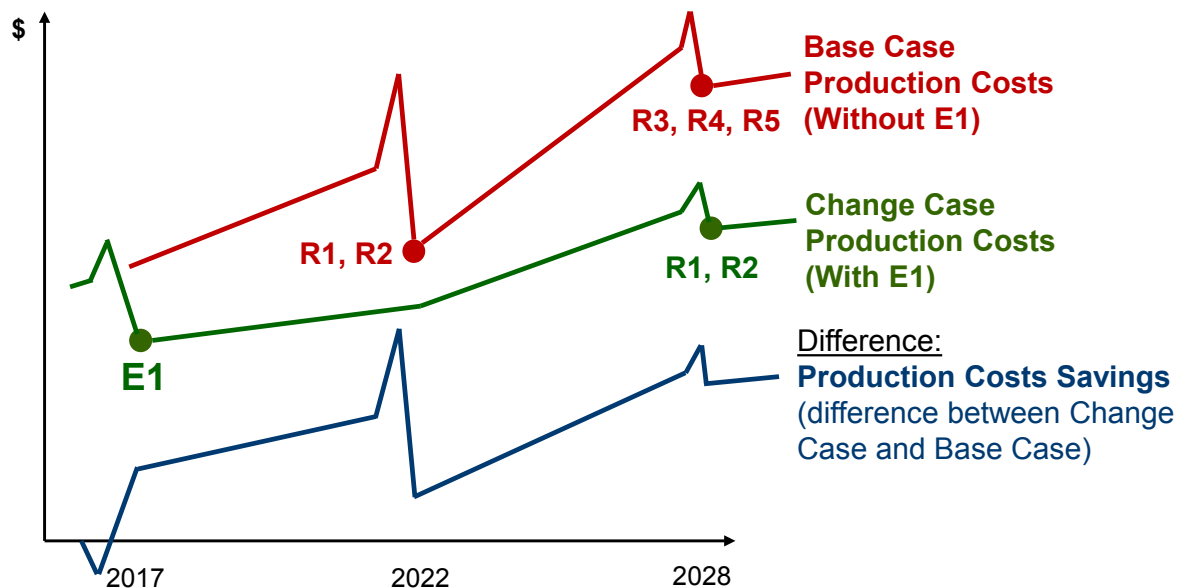
To estimate the value of production cost savings offered by the economic project requires simulation of total annual production costs for both the Base and the Change Cases. The difference between the two streams of production cost will determine the production cost savings of the economic project.

The expected shape of production costs for the Base Case (red line) and Change Case (green line) over time are demonstrated in Figure 6. Using the Base Case (red line) as an example, production costs are expected to rise over time due to increases in fuel costs and load growth. When R1 and R2 are installed in 2022, production costs may temporarily spike due to the transmission outages required to bring the new lines onto the network. Once R1 and R2 are on-line, however, production costs are expected to drop as projects built for reliability proposes often also reduce congestion and associated production costs. While production costs are expected to increase after that, a reduction in these costs must be expected in 2028 after R3, R4, and R5 come online. A similar pattern can be anticipated for the Change Case (green line), but with reduced production costs due to the installation of the economic project in 2017 and the Change Case reliability projects in 2028.

The production cost savings associated with the economic project (production costs in Base Case less the production costs in Change Case) are shown in blue. As shown, these annual values of these production savings first increase as the economic project is added, then further increase due to assumed growth in load and fuel costs. The production cost savings drop temporarily in 2022 when R1 and R2 reduce production costs in the Base Case, but after that, start to increase again with load and fuel costs through 2028. Based on the net effect of the reliability projects added to the Base Case and Change Case the net savings could either increase or decrease in 2028. The 2017 present value of the production cost savings offered by the economic project can be calculated by summing the discounted value of the annual savings represented by the blue line in Figure 6.

Note that Figure 6 also shows short “spikes” in production costs in the year when the new transmission projects are placed in service. These spikes in production costs relate to outages on the existing transmission system that are typically necessary to integrate new projects. They may not be substantial in many cases and are not typically simulated for the purpose of cost-benefit analyses. It is important, however, to keep the possibility of such production cost impacts in mind as new projects are evaluated. These impacts can be very large in cases where the existing system is highly utilized with limited flexibility or long outage durations (*e.g.*, to rebuild an existing line) can make such outages very expensive. Other than illustrating this potential impact in Figure 6, the case study did not further explore these costs and the potentially additional production cost savings associated with Project E1.

Figure 6
Production Costs and Savings from an Economic Project E1 Planned for 2017



To determine the annual values of the production cost savings illustrated in Figure 6 requires, at the minimum, production cost simulations for the Base Case and Change Case for 2017, 2022, and 2028. The annual values for the years between these simulations can then be estimated through interpolations. It is also important to recognize that production cost savings will not drop to zero in 2029. Rather, a more likely trend would be that the 2028 level of production cost savings would increase with load growth and fuel prices. To estimate these increases, the trend between 2022 and 2028 could be extrapolated to estimate these future values. An alternative, more conservative approach would be to assume that 2028 production cost savings will remain constant in real (*i.e.*, inflation adjusted) dollar terms, which would mean that the nominal value of estimated production cost savings would increase only with inflation after 2028. These approaches (or a combination of them) are routinely used by other system operators—such as SPP, MISO, and CAISO⁴⁹—for the purpose of estimating the value of annual benefits over the long-term.

⁴⁹ See SPP, 2010, MISO, 2011 and CAISO, 2005 and 2013. For example, to estimate production cost savings for the next 20 to 40 years, MISO interpolated the estimated savings between three simulated years, 2021, 2026, and 2031. MISO also extrapolated the benefit trend estimated for its 2026 and 2031 simulations for another 30 years. SPP's planning process for its Priority Projects estimated benefits for 40 years by simulating the systems for 2009, 2014, and 2019 and extrapolating the 2014–19 trend for another 10 years beyond 2019 before holding annual benefits constant in inflation-adjusted terms until the fortieth year. Similarly, the CAISO used simulations to estimate benefits for planning years 5 and 10, but estimated benefits for the ensuing 35 to 45 years by applying a 1% real escalation rate to planning-year 10 benefits to capture the combined impacts of inflation and other factors on likely future benefits.

The illustration of annual production cost savings in Figure 6 also shows that accurately capturing the value of production cost savings over time may require additional simulation runs. First, to estimate how production cost savings will increase after 2017 (but before they drop once R1 and R2 are added to the Base Case in 2022), it will generally be advisable to either: (a) simulate Base and Change Cases for 2021 and use these estimates to interpolate the years between 2017 and 2021; or (b) simulate a “hypothetical” 2022 Base Case without R1 and R2 and use that case to estimate hypothetical production cost savings for 2022, solely for the purpose of interpolating the value of benefits between 2017 and 2022.⁵⁰ The same approach would be necessary for 2027 (option a) or 2028 (option b) to yield more accurate interpolations of production costs savings between 2022 and 2028.

If construction-related transmission outages are anticipated to be significant, these outages would need to be reflected appropriately in both Base and Change Case simulations for 2017, 2022, and 2028 (or any other years during which these outages would occur). In addition, because the outages increase production costs only during the period *prior* to the in-service date of the new transmission project (but not after), the necessary outages may need to be simulated only for the prior years (*i.e.*, 2016, 2021 and 2027) or for “hypothetical” years 2017, 2022, and 2028 that do not yet have the new project placed in service. Our review of industry practice showed, however, that the cost of construction-related outages (or any other outages) to the existing system is not routinely considered in production cost simulations. We thus recommend that any outage-related benefits (or costs) be estimated separately from traditional estimates of production cost savings.

The production costs estimates from the simulations that ERCOT staff performed for this case study are summarized in Table 9. These simulations estimated Base Case production costs (highlighted red) and Change Case production costs (highlighted green) for 2017, 2022, and 2028. In addition, ERCOT staff simulated a “hypothetical” 2022 Base Case (without R1 and R2) and a “hypothetical” 2028 Base Case (with R1 and R2, but without R3, R4, and R5) as a reference point for interpolations between 2017 and 2022 as well as between 2022 and 2028.⁵¹

⁵⁰ The hypothetical 2022 Base Case simulation without R1 and R2 would not be a valid case from a system reliability perspective. This case would be used solely for the purpose of interpolating estimated production cost savings for the years between the 2017 and 2022 simulations. The reliability violations in 2022 without R1 and R2 would only affect a few hours of the year, and thus not distort the accuracy of simulated annual production cost savings.

⁵¹ To summarize, the simulation cases for which production cost savings were estimated by ERCOT staff for the purpose of this case study include the following combinations of reliability and economic projects:

	<u>2017</u>	<u>2022</u>	<u>2028</u>
Base Case	—	R1, R2	R1–R5
Hypothetical Base Case	—	—	R1, R2
Change Case	E1	E1	E1, R1, R2

The annual production cost savings shown in Table 9 are calculated as the difference in estimated annual production costs for the Base Case and the Change Case. As Table 9 shows, the pattern of production cost savings in this case study roughly follows the illustration shown in Figure 6: between 2022 and 2027, production cost savings increase from \$32 million to \$109 million, before dropping to \$90 million in 2028 (after R3, R4, and R5 are added in the Base Case). The same effect exists for 2021–22, although it is much smaller and not as visible in Table 9.

Table 9
Base and Change Case Production Costs
(\$ millions)

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Base Case	\$15,233	\$15,881	\$16,528	\$17,176	\$17,823	\$18,468	\$19,084	\$19,700	\$20,316	\$20,932	\$21,549	\$22,128
Change Case	\$15,228	\$15,870	\$16,511	\$17,153	\$17,794	\$18,436	\$19,037	\$19,637	\$20,238	\$20,839	\$21,440	\$22,038
Savings:	\$5	\$11	\$17	\$23	\$29	\$32	\$48	\$63	\$78	\$93	\$109	\$90

Assuming the estimated production cost savings for 2028 would stay constant in real (inflation-adjusted) dollar terms through 2057, the 40-year present value of the (discounted) annual production cost savings is equal to \$859 million. This present value of the economic project's production cost savings compares to the projects \$465 million present value of transmission revenue requirements and \$241 million in present value of avoided or deferred TRRs of reliability projects. As summarized in Table 10, this yields a total project benefit of at least \$1.1 billion (ignoring any other potential benefits), a benefit-cost ratio of 2.4, and a net benefit of \$635 million in present value terms (all 2017 dollars). Table 10 also shows that the \$1.1 billion present value of benefits is equivalent to levelized annual benefits of \$85 million, which compares favorably to both \$36 million of the economic project's levelized TRR and \$49 million in the economic project's first-year TRR estimated as 1/6th of the project's construction costs. Thus, the project is highly beneficial with societal benefits well in excess of project costs.

Under ERCOT's current approach, the \$49 million of the economic project's estimated first-year TRR would have been compared only to 2017 benefits, which are only \$5 million in annual production cost savings (since savings from deferred or avoided reliability projects would not be realized before 2022). Thus, while the project is highly beneficial from a long-term value perspective, that value would be foregone under ERCOT's current approach, which would reject the project by comparing only first-year benefits to first-year costs.

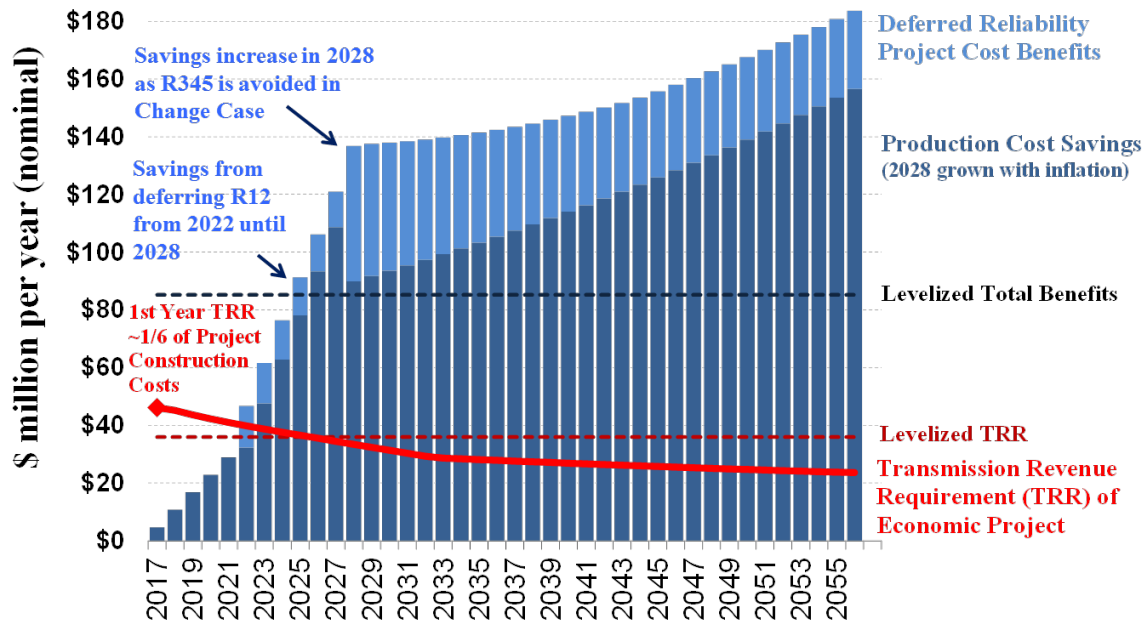
Table 10
Summary of Economic Project Costs and Benefits

	Project Costs (\$millions)	40-yr Present Value of TRR (\$millions)	Levelized TRR (\$millions/yr)	1/6th of Project Costs (\$millions/yr)
Economic Project Costs	\$291	\$465	\$36	\$49
Economic Project Benefits				
Avoided/deferred Reliability Projects		\$241		
Production Cost Savings		\$859		
Other benefits		n/a		
Total	Greater than:	\$1,100	\$85	
Net Benefit		\$635		
Benefit-cost Ratio		2.4		

Note, however, that comparing the present value of benefits with the present value of project TRR (or levelized benefits with levelized TRR) is not sufficient to determine if the 2017 assumed in-service date maximizes the value of the economic project. To answer that question, it is also helpful to compare annual project benefits with annual project costs over time. This is done in Figure 7. The annual TRR and levelized TRR of the economic project are shown as solid and dashed red lines. The benefits include both the production cost savings (in dark blue) and the value of deferring or avoiding reliability projects (in light blue). The levelized annual value of the quantified benefits is shown as the dark blue dashed line.

Figure 7 again shows that the \$85 million levelized annual value of quantified benefits significantly exceeds both the \$36 million levelized TRR of the project as well as the \$49 million estimated first-year TRR. The figure also shows that the first year production cost savings of \$5 million compare poorly to the first year TRR of \$49 million. However, despite the overall positive long-term value of the project, the economic project's quantified benefits do not exceed project TRR until 2022, when production cost savings are higher and the economic project is able to defer reliability upgrades R1 and R2. This means that the long-term value of the economic projects could be increased further by delaying the in-service date of the project until 2022—unless, of course, an earlier in-service data is justified by other benefits that have not been estimated or other considerations that would require the construction of the project prior to 2022.

Figure 7
Summary of Estimated Annual Transmission Benefits and Costs



D. EXPAND THE RANGE OF BENEFITS CONSIDERED AND ESTIMATED IN THE EVALUATION OF ECONOMIC TRANSMISSION PROJECTS

Section V of this report contains the complete discussion and our detailed recommendations concerning benefit metrics for both near-term and long-term implementation. For convenience and completeness, we summarize these recommendations in this discussion of refinements to ERCOT's planning processes. As discussed in Section V, we recommend that ERCOT more fully consider and estimate the economic value of transmission investments in its planning processes. This requires expanding the economic benefits and costs of transmission investments considered. The wider range of benefits will more accurately reflect the value that new transmission can provide to the system. For the most part, this value reflects the higher system wide costs that market participants would be exposed to absent the new transmission.

As it would be difficult for ERCOT to evaluate the complete set of benefit metrics shown in Table 6 for each proposed project, we recommend that ERCOT implement only a subset of these benefits and benefit metrics in the near term. As discussed in Section V, we recommend that ERCOT improve its treatment of production cost savings and the benefits from deferring or avoiding reliability projects. We also recommend that ERCOT add seven economic benefit metrics to its economic evaluation process, two of which would be applied as a typical multiplier to standard estimates of production cost savings. These additional metrics could be applied to each major economic project or portfolios of projects found most promising based on production cost savings and avoided or deferred reliability projects.

The scope of production cost savings, as currently estimated by ERCOT, should be expanded beyond the estimates of savings of a project's first year to include, for example, estimated savings for years 5 and 10 of the project and using these annual estimates to develop estimates for the long-term present value of a project's production cost benefits. The estimated benefit of an economic project's ability to defer or avoid reliability projects should similarly be expanded beyond the project's first year to reflect the present value of reduced or deferred reliability investments.

In terms of additional benefits to be estimated, we recommend that ERCOT: (1) modify its long-term market simulations to capture the impact of forced generation unit outages and ancillary service unit designations; (2) more fully estimate the reduced (or possibly increased) production cost due to project-related changes in transmission losses; (3) study the typical impact of transmission outages on project-related production cost savings to develop a multiplier that could be applied to standard estimates of production cost savings going forward; (4) similarly develop a multiplier to capture the disproportionately higher project-related benefits during weather-related spikes in peak loads; (5) modify simulations to more completely capture cost reductions (or increases) due to a project's impact on the operational cycling of power plants; (6) estimate any decreases (or increases) in installed capacity requirements due to changes in on-peak transmission losses; and (7) more fully consider emission-related costs (including those for long-term risk mitigation benefits).

We further recommend that, at this point, the other benefits in Table 6 be considered, discussed, and analyzed on a case-by-case basis for projects that are anticipated to offer significant value in terms of the individual benefit types. For example, an evaluation of generation cost savings may be undertaken in the future in the context of a transmission project that allows for either the deferral of generation investments (*e.g.*, by allowing plants in neighboring regions with surplus capacity to "switch" into ERCOT) or the development of new generating plants to be shifted from high-cost locations (*e.g.*, areas that have higher land costs or would require greater investment in emission controls) to lower-cost locations. Similarly, project-specific benefits should be evaluated on a case-by-case basis as future projects offer unique benefits, such as opportunities for improved utilization of transmission rights-of-way or the creation of low-cost options for possible future transmission projects.

To implement the recommended additional benefit metrics in the transmission planning process, it will be necessary to develop and refine proposed approaches through the RPG stakeholder process. We also anticipate that stakeholder workshops be used to fully explain the details of each proposed benefit metric and document with case studies how ERCOT has quantified its value. As ERCOT's experience with project-specific additional benefits metrics increases over time, these metrics should then be added to the set of metrics that is routinely considered.

E. IMPROVE USE OF SCENARIOS AND SENSITIVITIES

Recognizing the uncertainties about the future, particularly from a long-term perspective, we recommend that ERCOT improve its use of scenarios and sensitivities considered in the long-term planning process. It is important for ERCOT to distinguish in its near- and long-term simulation efforts between the short-term uncertainties that can impact the operation of the transmission network in any future year and the long-term uncertainties that will define the industry in the future. The short-term uncertainties should not be used for defining long-term scenarios, but instead be captured through modeling of the uncertainties within each scenario. The long-term uncertainties on the other hand should be explored and agreed upon through the development of a range of scenarios that reasonably reflect the range of long-term uncertainties.

Stakeholder feedback provided insight into the scenario-development process that had been undertaken in the last two years to create plausible and reasonable scenarios about future market conditions. While having made some significant progress, there are opportunities to meaningfully improve on both the process used to develop the scenarios and how scenario analysis, and the accompanying sensitivity analyses, can be used to improve ERCOT's planning process. It is clear that stakeholders will accept the results of long-term studies more readily if they understand the assumptions embodied in the scenarios and believe they reflect a reasonably complete range of plausible future market conditions.

To further improve the understanding and buy-in of long-term planning efforts, ERCOT should consider refining its stakeholder process for developing scenarios. Based on the experience with ERCOT's recent effort, the next iteration of this process can be defined more clearly from the onset and specify more concisely how scenarios will be used in the long-term planning effort and how long-term planning results will be used in the RTP process. It is important for ERCOT to reiterate its invitation to all potentially interested parties to participate in this process and make clear that stakeholder buy-in for the scenario assumptions and planning effort will lead to "results that matter."

To achieve these goals, we recommend that the scenario development process be a facilitated stakeholder-driven process that includes representatives from each sector within the electric power industry as well as experts from outside of ERCOT and the power industry (such as from the oil and gas sectors) to share their views on the future of the state's economy and energy industry, including their perspectives regarding electricity usages and potential growth for the industry. The scenarios should reflect a wide range of possible future outcomes in terms of ERCOT-wide and localized load growth, generation mix and locations, and fuel prices.

Some stakeholders have raised concerns that transmission investment should not be based on projections of market conditions beyond several years, given the considerable long-term uncertainties faced by the industry. Planners may want to stay away from such investment decisions, fearing that uncertain futures could dramatically change the value of those investments

and result in regrets. We believe, however, that the likelihood of inefficient investments or “regrets” is just as high when decisions about long-lived assets are made solely based on near-term considerations. Shying away from making investment decisions because of difficulties in predicting the future could lead to a perpetual focus on transmission upgrades that address only the most urgent near-term needs, such as reliability violations, and thereby forego opportunities to capture higher values by making investments that could address longer-term needs much more effectively. It is also likely to lead to inefficient use of scarce resources, such as available transmission corridors and rights-of-way. To address this challenge, we recommend that ERCOT continue to evaluate long-term uncertainties through scenario-based analyses. Such scenario-based long-term planning approaches are widely used by other industries (such as the oil and gas industry)⁵² and have also been employed, for example, by SPP’s Integrated Transmission Planning (ITP) and the MISO Transmission Expansion Plan (MTEP) processes.⁵³ The scenarios specified by SPP and MISO in their 10 to 20 year planning processes take into account (though only to a limited degree) divergent assumptions about renewable energy additions, load levels, and a few other factors.

Evaluating long-term uncertainties through various future scenarios is important given the long useful life of new transmission facilities that can exceed four or five decades. Long-term uncertainties around fuel price trends, locations, and size of future load and generation patterns, economic and public policy-driven changes to future market rules or industry structure, and technological changes can substantially affect the need and size of future transmission projects. Results from scenario-based analyses of these long-term uncertainties can be used to: (1) identify “least-regrets” projects whose value would be robust across most futures; and (2) identify or evaluate possible project modifications (such as building a single circuit line on double circuit towers) in order to create valuable options that can be exercised in the future depending on how the industry actually evolves. In other words, the range in long-term values of economic transmission projects under the various scenarios should be used both to assess the robustness of a project’s cost effectiveness and to help identify project modifications that increase the flexibility of the system to adapt to changing market conditions.

In addition to a scenario-based consideration of long-term uncertainties, we recommend that short-term uncertainties be considered separately. Short-term uncertainties that exist within any one of the scenarios—such as weather-related load fluctuations, hydrological uncertainties, short- and medium-term fuel price volatility, and generation and transmission contingencies—should not drive scenario definitions. These uncertainties should be simulated probabilistically

⁵² For example, see Royal Dutch Shell, 2013. See also Wilkinson and Kupers, 2013.

⁵³ See, for example, MISO, 2011 and SPP, 2010.

or through sensitivity analyses for each of the chosen scenarios to capture the full range of the societal value of transmission investments.⁵⁴

The simulation of short-term uncertainties can be particularly important because the value of transmission projects is disproportionately higher during more challenging market conditions that are created by such uncertainties. Not analyzing the projects under challenging, but realistic, market conditions risks underestimating their values. The impact of near-term uncertainties can be analyzed by specifying probabilities and correlations for key variables, importance sampling, and undertaking Monte Carlo simulations for the selected set of cases. However, such complex and time-consuming probabilistic simulations are not always necessary. Often, a limited set of sensitivity cases (*e.g.*, 90/10, 50/50, 10/90 load forecasts) and case studies (*e.g.*, simulating past extreme contingencies, outages, weather patterns) can serve as an important step toward capturing the actual values of projects, which can help planners better understand how these near-term uncertainties can affect the expected value of projects in any particular future year.

For example, to address how uncertainties affect the value of transmission projects, the California Energy Commission developed a framework for assessing the expected value of new transmission facilities under a range of uncertain variables. Their recommended approach identifies the key variables that are expected to have a significant impact on economic benefits, establishes a range of values to be analyzed for each variable, and creates cases that focus on the most relevant sets of values for further analysis, including the probabilities for each case.⁵⁵ As Luminant pointed out, ERCOT also previously performed simulations for normal, higher-than-normal, and lower-than-normal levels of loads and natural gas prices in its evaluation of the Houston Import Project. The simulations showed that a \$45.3 million annual consumer benefit for the Base Case simulation (normal load and gas prices) compared to a \$52.8 million probability-weighted average of benefits for all simulated load and gas price conditions,⁵⁶ illustrating the extent to which the value of transmission projects can depend on the consideration of key uncertainties.

F. ENHANCE ECONOMIC PROJECT AND BENEFITS/COSTS IDENTIFICATION PROCESS

Finally, we recommend that ERCOT refine its process for identifying candidate economic transmission projects and their expected societal benefits and costs. The transmission planning process and the considerations for transmission-related benefits go hand in hand. The choice of what projects to pursue is directly linked to how planners and developers view the need for

⁵⁴ For simplified frameworks taking into account both long-term and short-term uncertainties for transmission planning in the context of renewable generation expansion, see Munoz, *et al.*, 2013; Van Der Weijde and Hobbs, 2012; and Park and Baldick, 2013.

⁵⁵ Toolsen, 2005.

⁵⁶ ERCOT, 2011a, p. 10.

transmission projects and, thereby, the potential benefits that these projects would provide. Through our experience we have found that a successful approach to the identification of potentially beneficial projects and their benefits is to consider qualitatively all the potential benefits offered by the contemplated transmission investments at the outset, when assessing the need of certain projects. Putting all the benefits on the table upfront helps avoid encumbering the overall planning process by focusing too early on time-consuming market simulations that may not even be able to capture many of the identified benefits.

We thus recommend that ERCOT consider supplementing its planning efforts with a structured process that allows market participants to propose candidate economic projects and identify their anticipated benefits. For example, under this process ERCOT could gather system planners, project developers, and other stakeholders to identify *potential* transmission projects that could supplement or replace baseline reliability projects and develop a comprehensive list of their likely benefits. This project identification effort would be facilitated by ERCOT and involve market participants to provide information about existing and anticipated system conditions. The participants would propose and document project ideas while simultaneously describing the projects' anticipated benefits—without limitations imposed by available analytical frameworks. The goal of this effort is to identify a wide range of possible projects that could more efficiently address reliability needs, meet public policy objectives, and offer economic benefits without impeding or limiting the scope of options and benefits considered at the outset. The only two questions that should be asked at this stage of the process are: (a) what transmission projects would likely be beneficial in addition to or instead of those that have been identified to meet reliability standards? and (b) what are the likely types of benefits that these projects would offer and why are they expected to be significant?

Even if the values of some benefits are not easily estimated with existing tools, they should still be considered and at least discussed qualitatively. Once proposed projects and their likely benefits have been specified, ERCOT will need to prioritize the proposed projects based on the stakeholder input and undertake benefit-cost analysis based on available analytical capabilities to determine whether a proposed project meets its economic planning requirements. As discussed in Section V of this report, some of the identified economic benefits can be measured readily through traditional benefit metrics, such as production cost or avoided reliability project cost savings. These traditional benefit metrics would be analyzed for every project or portfolio of projects through a refined existing framework within each planning cycle. Other benefits may not lend themselves to routine analyses through formulaic benefit metrics. The value of those benefits would be estimated when the anticipated magnitude is significant such that it could materially affect the attractiveness of the proposed projects. Benefits which could be significant but are more difficult to estimate should be analyzed by estimating at least their likely range and magnitudes—rather than implicitly assuming that they have zero value only because their precise values are difficult to calculate. Benefits that are unique to specific projects could be assessed only if and when they are applicable. This project evaluation step is also the step where non-

transmission alternatives should be considered when comparing benefits and costs of proposed projects.

We have also found that, while it is intuitive to estimate the economic benefits associated with every proposed transmission project, often several projects could be considered jointly because the combination of the projects can provide higher (or in some cases lower) benefits than the sum of each project's individual benefits. By analogy, a particular section of the interstate highway system might have little value unless it is integrated with the rest of the system. Likewise, a group of transmission facilities may provide substantially greater system-wide benefits than the sum of the benefits for each individual segment that makes up the group. On the other hand, competing or conflicting projects would need to be evaluated independently. Such distinction reinforces the need to describe and understand the potential benefits of each project upfront before delving into the quantitative analyses. If a group of facilities can offer more benefits jointly than independently, developing efficient portfolios of transmission projects would require iterative analyses of several transmission options and non-transmission alternatives in this step.

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APPENDIX A – TYPES OF TRANSMISSION BENEFITS AND THE IMPORTANCE TO CONSIDER A COMPLETE SET OF BENEFITS

As is generally understood at least conceptually, transmission investments can support a wide range of benefits. The most common benefits include increased reliability, decreased transmission congestion, renewables integration, reduced losses, reduced resource adequacy requirements, and increased competition in power markets. Some of these benefits spread across wide geographic regions and multiple utility service areas and states, and can significantly affect market participants ranging from generators to retail electricity customers. Over the long-life of the transmission assets, the nature and the magnitude of the benefits can also change significantly. For example, benefits associated with today's transmission grid, such as the ability to operate competitive wholesale electricity markets, could hardly have been imagined or estimated when the facilities were built four or five decades ago, long before the advent of open access to the transmission grid.

Recent transmission planning experiences have also shown that the scope of transmission-related benefits generally extends beyond the main driver of a particular project. While many transmission investments are motivated by a single driver—such as reliability, congestion relief, or renewable generation integration—the benefits of these transmission investments generally extend beyond the individual driver. For example, many reliability-driven projects also will reduce congestion and support the integration of renewable generation. Similarly, a transmission project driven by congestion-relief objectives also will also increase system reliability, help to avoid or delay reliability projects that would otherwise be needed in the future, or reduce system-wide investment needs by allowing access to lower-cost generation resources. This multi-purpose, multi-value aspect of transmission investments requires a more systematic analysis of the wide range of transmission-related benefits and the interaction of transmission investments with other system-wide costs and non-transmission investments.

A. PRODUCTION COST SAVINGS AS A TRADITIONAL BENEFIT METRIC

The most commonly-considered economic benefits of transmission investments are estimated reductions in simulated fuel and other variable operating costs of power generation (generally referred to as production cost savings) and the impact on wholesale electricity market prices (in many cases referred to as locational marginal prices or LMPs) at load-serving locations of the grid. These **production cost savings** and **load LMP benefits** are typically estimated with production cost models that in order to streamline the modeling effort are configured to simulate generation dispatch and transmission congestion based on simplified approximations of power flows, predefined transmission constraints, and normalized system conditions.

In a recent assessment of RTO performance by FERC, the majority of RTOs cited congestion reliefs as a main benefit from expanding transmission capacity. For example, PJM noted that

market simulations of recently-approved high-voltage upgrades indicate that these upgrades will reduce congestion charges by approximately \$1.7 billion compared to congestion charges without the upgrades.⁵⁷ While changes in total congestion charges are informative, the economic value of such congestion relieve is generally reflected in production cost savings (from an economy-wide perspective) and load LMP benefits (from the perspective of customers in restructured retail electricity markets) because a reduction in congestion typically increases the use of more efficient (lower cost) generators over the inefficient (higher cost) ones.

Since production cost simulations have become a standard tool for many transmission developers and grid operators, production cost savings estimation is the analysis that can readily be repeated for all proposed transmission projects or groups of projects. While production cost savings are readily estimated (based on assumptions), the results only provide estimates of the short-term dispatch-cost savings of system operations. These savings are only a portion of the overall economic benefits provided by transmission investments and do not capture a wide range of other transmission-related benefits, including many long-term capital and operational cost savings. For example, as a Western Electric Coordinating Council (WECC) planning group recognized:

The real societal [*i.e.*, overall economic] benefit from adding transmission capacity comes in the form of enhanced reliability, reduced market power, decreases in system capital and variable operating costs and changes in total demand. The benefits associated with reliability, capital costs, market power and demand are not included in this [type of production cost simulation] analysis.⁵⁸

In addition, as explained in more detail in Appendix B, production cost simulations as traditionally undertaken are based on a number of simplified assumptions that can significantly understate the derived estimates of production cost savings.

B. EXAMPLES OF A MORE FULLY ARTICULATED SET OF TRANSMISSION BENEFITS

Aside from production cost savings, other benefits—particularly those associated with improved reliability, reduced generation capital costs, reduced market power and demand—are often omitted in many transmission benefit-cost analyses. These omitted benefits are sometimes inaccurately viewed as “soft” or “intangible” benefits simply because they are not yet routinely estimated by transmission owners and system operators. Even though some of these additional benefits can be difficult to estimate in certain situations, omitting them effectively assumes these benefits are zero, which may not be the case.

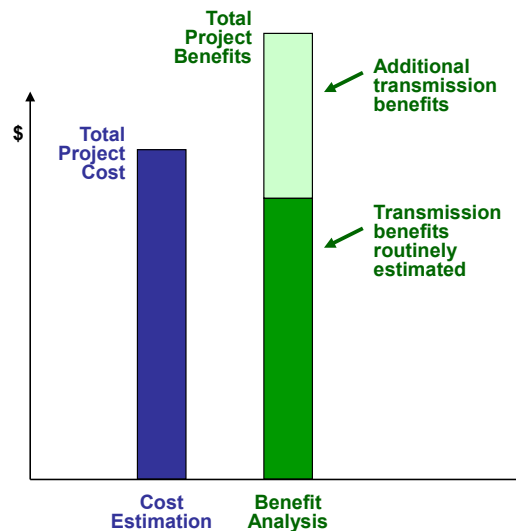
⁵⁷ FERC Performance Metrics, 2011, Appendix H: PJM, p. 275. Additionally, an 82% reduction in annual congestion costs is forecast from \$980 million “as is” 2012 baseline to \$173 million “as planned” based on PJM’s 2016 RTEP (Cash, 2013).

⁵⁸ SSG-WI Transmission Report, 2003.

Instead of assuming some of the more difficult to estimate benefits have a zero value, estimating the approximate range of likely benefits will yield a more accurate benefit-cost analysis and provide more insightful comparisons that avoid rejecting beneficial transmission investments. For example, transmission lines can increase competition in wholesale electricity markets as more generators gain access to a wider set of customers. In some cases, transmission upgrades can reduce a region's resource adequacy needs and offer access to lower-cost generating resources. While estimates of resource adequacy or competitive benefits might not be precise at times, rough estimates of the likely magnitude of these benefits can generally be developed. As conceptually illustrated in Figure 8, overlooking or ignoring such difficult-to-quantify or not-commonly-estimated benefits can lead to rejection of otherwise desirable projects. Because the benefits of transmission investments are measured in large part as a reduction in system-wide costs, a failure to consider the full economic benefits of transmission investments is equivalent to not considering all costs and the potentially very-high-cost outcomes that market participants would be exposed to in the absence of these investments.

In other words, being “conservative” and to understate the likely value of the economic benefits of transmission investments means to be conservative in estimating likely future costs imposed on customers and society as a whole in the absence of the project. Thus, unbiased estimates of all benefits that are neither too conservative nor too optimistic will yield better investment decisions and more efficient, lower-cost outcomes in the long term.

Figure 8



As we noted in a prior report for WIRES,⁵⁹ the post-construction assessment of the Arrowhead-Weston transmission line in Wisconsin, developed by American Transmission Company (ATC)

⁵⁹ Pfeifenberger and Hou, 2011, Section IV.

in 2008, provides a good example of the broad range of benefits associated with that project. The primary driver of the Arrowhead-Weston line was to increase reliability in northwestern and central Wisconsin by adding another high voltage transmission line in what the federal government designated at the time as “the second-most constrained transmission system interface in the country.”⁶⁰ The project addressed this **reliability** issue by adding 600 MW of carrying capacity and improving voltage support, the impact of which was noticeable in both Wisconsin and in southeastern Minnesota. By also **reducing congestion**, ATC estimated that the line allowed Wisconsin utilities to decrease their power purchase costs by \$5.1 million annually, saving \$94 million in net present value terms over the ensuing 40 years. Similarly, ATC estimated that the project saved \$1.2 million in **reduced costs for scheduled maintenance**. The high voltage of the line (345 kV) also **reduced on-peak energy losses** on the system by 35 MW, which **reduced new generation investments** equivalent to a 40 MW power plant. The reduced losses also avoid generating 5.7 million MWh of electricity that would **reduce CO₂ emissions** by 5.3 million tons over the initial 40-year life of the facility. In addition, the transmission line has the capability to deliver hydro resources from Canada and wind power from the Dakotas and interconnect local renewable generation to **help Wisconsin meet its RPS requirements**. The construction of the line **supported 2,560 jobs**, generated \$9.5 million in **tax revenue**, created \$464 million in total **economic stimulus**, and will provide \$62 million of **income to local communities** over the next 40 years. The increased reliability of the electric system has provided **economic development benefits** by improving the operations of existing commercial and industrial customers and attracting new customers. Lastly, the project also provided **insurance value against extreme market conditions** as was illustrated in a North American Electric Reliability Corporation (NERC) report which noted that if the Arrowhead-Weston line had been in service earlier, it would have **averted blackouts** in the region which impacted an area that stretched from Wisconsin and Minnesota to western Ontario and Saskatchewan, affecting hundreds of thousands of customers.

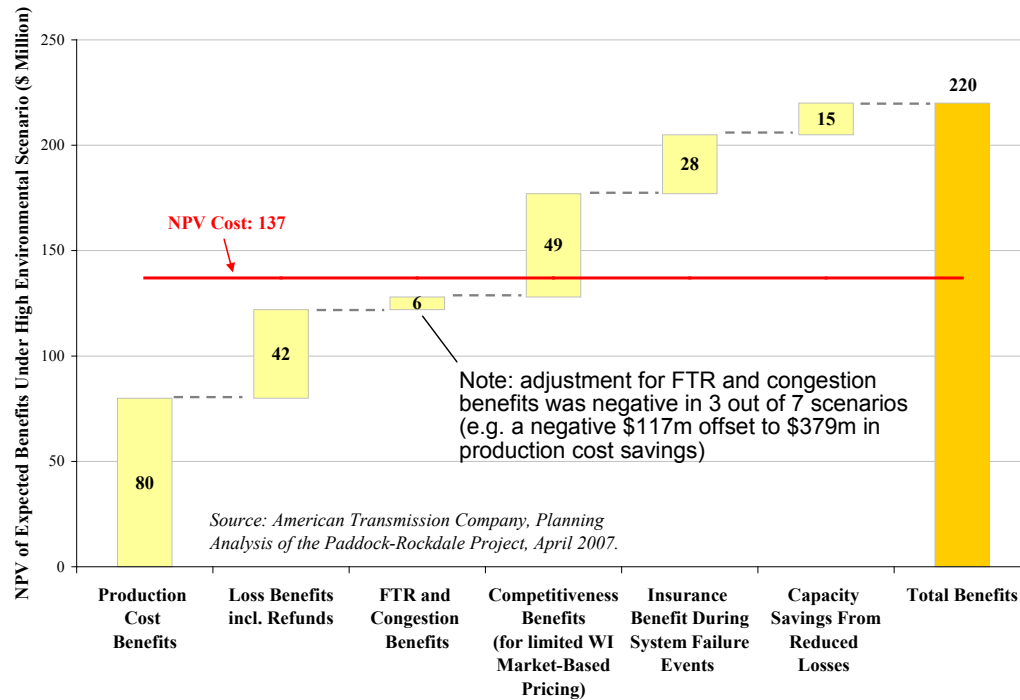
Figure 9 and Figure 10 summarize examples of transmission benefit-cost analyses that identified and estimated a number of the transmission-related benefits discussed above. As shown, the examples show projects that provide benefits significantly in excess of transmission-related rate increases, with the estimated economic benefits exceeding their costs by 60% to 70%. These examples also show that the traditionally estimated production cost savings are only a portion of the total benefits.

A comprehensive analysis of a broad range of transmission-related benefits also may show that some benefits have negative values (i.e., representing costs). For example, transmission investments that help integrate lower-cost but distant generating resources also can increase system-wide transmission losses. Some transmission expansions can lead to increased emissions

⁶⁰ ATC (2009), p. 7.

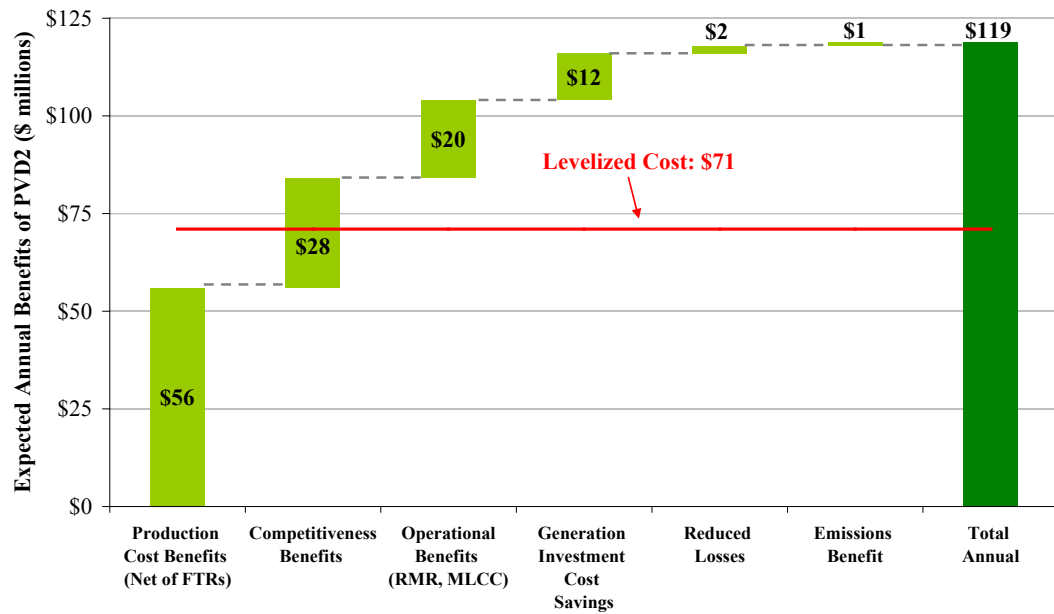
and associated environmental costs; or certain transmission projects may cause larger environmental impacts in terms of their land use. From a consumer perspective, new transmission could decrease the value of existing physical or financial transmission rights, thereby offsetting benefits related to congestion relief or the increased availability of transmission rights.⁶¹

Figure 9
Total Benefits Quantified for ATC's Paddock-Rockdale Project



⁶¹ The economic analysis of the Paddock-Rockdale Project is a good example of transmission benefits that could be positive or negative. We have presented in Figure 9 the summary results of one of the seven scenarios examined when ATC evaluated the project. In Figure 9, we show that additional “FTR and Congestion Benefits” added \$6 million to the savings of the project. However, the results for the other Scenarios analyzed by ATC showed different patterns. Specifically, the “FTR and Congestion Benefits” was actually negative in three of the seven scenarios. In fact, it had a negative value of \$117 million in one of them, which offset \$379 million in production cost savings for that scenario. These results also document that benefits can vary greatly across possible different futures, which illustrates the importance of scenario analysis to evaluate the robustness of project economics as we discuss further below.

Figure 10
Total Benefits Quantified for Southern California Edison's Palo Verde-Devers 2 Project



Source: CAISO PVD2 Report, 2005.

APPENDIX B – EXPERIENCE WITH IDENTIFYING AND ANALYZING A BROAD RANGE OF TRANSMISSION BENEFITS

This appendix to the report presents a technical discussion of the full range of the economic benefits of transmission investments identified in Table ES-1 and Table 6 of the main report and summarizes the available industry experience on how they are estimated. It also documents current industry practices in the analysis of these benefits, describes in detail how certain benefits not traditionally quantified by ERCOT can be measured, and explains why they can be important in assessing the benefit-cost impact of proposed transmission projects. Consistent with Table ES-1 and Table 6, the transmission benefits discussed in more detail include:

1. Production cost savings;
2. Reliability and resource adequacy benefits;
3. Generation capacity cost savings;
4. Market benefits, such as improved competition and market liquidity;
5. Environmental benefits;
6. Public policy benefits;
7. Employment and economic development benefits; and
8. Other project-specific benefits such as storm hardening, increased load serving capability, synergies with future transmission projects, increased fuel diversity and resource planning flexibility, increased wheeling revenues, increased transmission rights and customer congestion-hedging value, and HVDC operational benefits.

The remainder of this appendix first presents these benefit metrics, their descriptions and industry experiences in the summary tables on the following pages. These summary tables are then followed by a narrative discussion. This appendix is largely based on Section VI of our recently-published report *The Benefits of Electric Transmission: Identifying and Analyzing the Value of Investments*, prepared for WIRES in July 2013. The research conducted for Section VI in the WIRES report was conducted in parallel to our engagement with ERCOT, with both engagements benefiting from the synergies of the two efforts. Some of the discussion in this appendix and the WIRES section also is based on a report prepared by the SPP Metrics Task Force (*Benefits for the 2013 Regional Cost Allocation Review*, September 13, 2012), which we helped prepare.

1. Additional Production Cost Savings				
Transmission Benefit		Benefit Description	Approach to Estimating Benefit	Examples
1. Additional Production Cost Savings				
a.	Reduced impact of forced generation outages	Consideration of both planned and forced generation outages will increase impact	Consider both planned and (at least one draw of) forced outages in market simulations.	Already considered in most (but not all) RTOs
b.	Reduced transmission energy losses	Reduced energy losses incurred in transmittal of power from generation to loads reduces production costs	Either (1) simulate losses in production cost models; (2) estimate changes in losses with power flow models for range of hours; or (3) estimate how cost of supplying losses will likely change with marginal loss charges	CAISO (PVD2) ATC Paddock-Rockdale SPP (RCAR)
c.	Reduced congestion due to transmission outages	Reduced production costs during transmission outages that significantly increase transmission congestion	Introduce data set of normalized outage schedule (not including extreme events) into simulations or reduce limits of constraints that make constraints bind more frequently	SPP (RCAR) RITELine
d.	Mitigation of extreme events and system contingencies	Reduced production costs during extreme events, such as unusual weather conditions, fuel shortages, or multiple outages.	Calculate the probability-weighted production cost benefits through production cost simulation for a set of extreme historical market conditions	CAISO (PVD2) ATC Paddock-Rockdale
e.	Mitigation of weather and load uncertainty	Reduced production costs during higher than normal load conditions or significant shifts in regional weather patterns	Use SPP suggested modeling of 90/10 and 10/90 load conditions as well as scenarios reflecting common regional weather patterns	SPP (RCAR)
f.	Reduced costs due to imperfect foresight of real-time conditions	Reduced production costs during deviations from forecasted load conditions, intermittent resource generation, or plant outages	Simulate one set of anticipated load and generation conditions for commitment (e.g., day ahead) and another set of load and generation conditions during real-time based on historical data	
g.	Reduced cost of cycling power plants	Reduced production costs due to reduction in costly cycling of power plants	Further develop and test production cost simulation to fully quantify this potential benefit ; include long-term impact on maintenance costs	WECC study
h.	Reduced amounts and costs of ancillary services	Reduced production costs for required level of operating reserves	Analyze quantity and type of ancillary services needed with and without the contemplated transmission investments	NTTG WestConnect MISO MVP
i.	Mitigation RMR conditions	Reduced dispatch of high-cost RMR generators	Changes in RMR determined with external model used as input to production cost simulations	ITC-Entergy CAISO (PVD2)

2–3. Reliability and Resource Adequacy Benefits and Generation Capacity Cost Savings

Transmission Benefit		Benefit Description	Approach to Estimating Benefit	Examples
2. Reliability and Resource Adequacy Benefits				
a.	Avoided or deferred reliability projects	Reduced costs on avoided or delayed transmission lines otherwise required to meet future reliability standards	Calculate present value of difference in revenue requirements of future reliability projects with and without transmission line, including trajectory of when lines are likely to be installed	ERCOT All RTOs and non-RTOs ITC-Entergy analysis MISO MVP
b.	Reduced loss of load probability <u>Or:</u>	Reduced frequency of loss of load events (if planning reserve margin is not changed despite lower LOLEs)	Calculate value of reliability benefit by multiplying the estimated reduction in Expected Unserved Energy (MWh) by the customer-weighted average Value of Lost Load (\$/MWh)	SPP (RCAR)
c.	Reduced planning reserve margin	Reduced investment in capacity to meet resource adequacy requirements (if planning reserve margin is reduced)	Calculate present value of difference in estimated net cost of new entry (Net CONE) with and without transmission line due to reduced resource adequacy requirements	MISO MVP SPP (RCAR)
3. Generation Investment Cost Savings				
a.	Generation investment cost benefits from reduced peak energy losses	Reduced energy losses during peak load reduces generation capacity investment needs	Calculate present value of difference in estimated net cost of new entry (Net CONE) with and without transmission line due to capacity savings from reduced energy losses	ATC Paddock-Rockdale MISO MVP SPP ITC-Entergy
b.	Deferred generation capacity investments	Reduced costs of generation capacity investments through expanded import capability into resource-constrained areas	Calculate present value of capacity cost savings due to deferred generation investments based on Net CONE or capacity market price data	ITC-Entergy
c.	Access to lower-cost generation	Reduced total cost of generation due to ability to locate units in a more economically efficient location	Calculate reduction in total costs from changes in the location of generation attributed to access provided by new transmission line	CAISO (PVD2) MISO ATC Paddock-Rockdale

4–7. Market, Environmental, Public Policy, and Economic Stimulus Benefits				
Transmission Benefit		Benefit Description	Approach to Estimating Benefit	Examples
4. Market Benefits				
a.	Increased competition	Reduced bid prices in wholesale market due to increased competition amongst generators	Calculate reduction in bids due to increased competition by modeling supplier bid behavior based on market structure and prevalence of “pivotal suppliers”	ATC Paddock-Rockdale CAISO (PVD2, Path 26 Upgrade)
b.	Increased market liquidity	Reduced transaction costs and price uncertainty	Estimate differences in bid-ask spreads for more and less liquid markets; estimate impact on transmission upgrades on market liquidity	SCE (PVD2)
5. Environmental Benefits				
a.	Reduced emissions of air pollutants	Reduced output from generation resources with high emissions	Additional calculations to determine net benefit emission reductions not already reflected in production cost savings	NYISO CAISO
b.	Improved utilization of transmission corridors	Preserve option to build transmission upgrade on an existing corridor or reduce the cost of foreclosing that option	Compare cost and benefits of upsizing transmission project (e.g., single circuit line on double-circuit towers; 765kV line operated at 345kV)	
6.	Public Policy Benefits	Reduced cost of meeting policy goals, such as RPS	Calculate avoided cost of most cost effective solution to provide compliance to policy goal	ERCOT CREZ ISO-NE, CAISO MISO MVP SPP (RCAR)
7.	Employment and Economic Development Benefits	Increased full-time equivalent (FTE) years of employment, economic activity related to new transmission line, and tax revenues	A separate analysis required for quantification of employment and economic activity benefits that are not additive to other benefits.	SPP MISO MVP

8. Other Project-Specific Benefits				
Transmission Benefit		Benefit Description	Approach to Estimating Benefit	Examples
8. Other Project-Specific Benefits				
a.	Storm hardening	Increased storm resilience of existing grid transmission system	Estimate VOLL of reduced storm-related outages. Or estimate acceptable avoided costs of upgrades to existing system	ITC-Entergy
b.	Increased load serving capability	Increase future load-serving capability ahead of specific load interconnection requests	Avoided cost of incremental future upgrades; economic development benefit of infrastructure that can	
c.	Synergies with future transmission projects	Provide option for a lower-cost upgrade of other transmission lines than would otherwise be possible, as well as additional options for future transmission expansions	Value can be identified through studies evaluating a range of futures that would allow for evaluation of “no regrets” projects that are valuable on a stand-alone basis and can be used as an element of a larger potential regional transmission build out	CAISO (Tehachapi) MISO MVP
d.	Increased fuel diversity and resource planning flexibility	Interconnecting areas with different resource mixes or allow for resource planning flexibility		
e.	Increased wheeling revenues	Increased wheeling revenues result from transmission lines increasing export capabilities.	Estimate based on transmission service requests or interchanges between areas as estimated in market simulations	SPP (RCAR) ITC-Entergy
f.	Increased transmission rights and customer congestion-hedging value	Additional physical transmission rights that allow for increased hedging of congestion charges.		ATC Paddock-Rockdale
g.	Operational benefits of HVDC transmission	Enhanced reliability and reduced system operations costs		

A. PRODUCTION COST SAVINGS

The most commonly used metric for measuring the economic benefits of transmission investments is the reductions in production costs. Production cost savings include savings in fuel and other variable operating costs of power generation that are realized when transmission projects allow for the increased dispatch of suppliers that have lower incremental costs of production, displacing higher-cost supplies. Lower production costs will generally also reduce market prices as lower-cost suppliers will set market clearing prices more frequently than without the transmission project. The tools used to estimate the changes in production costs and wholesale electricity prices are typically security-constrained production cost models that simulate the hourly operations of the electric system and the wholesale electricity market by emulating how system operators would commit and dispatch generation resources to serve load at least cost, subject to transmission and operating constraints.

1. Definition and Method of Calculating Production Cost Savings

Within production cost models, changes in system-wide production costs can be estimated readily. The traditional method for estimating the changes in production costs associated with a proposed transmission project is to compare the production costs (or “adjusted production costs”)⁶² with and without the transmission project. Analysts typically call the market simulations without the transmission project the “Base Case” and the simulations with the transmission project the “Change Case.”

These simulations can also provide estimates of how the proposed transmission projects affect the pattern of transmission congestion, the overall production costs necessary to serve load, the prices that utilities (and ultimately their customers) pay for market-based energy purchases, and the revenues that generators receive for market-based energy sales. Thus, through production

⁶² These estimated changes in production costs, however, do not necessarily capture how costs change within individual regions if there are purchases and sales from neighboring regions. This is because the cost of serving these regions and areas will not only depend on the production cost of generating plants within the region or area, but will also depend on the extent to which power is bought from or sold to neighbors. Such purchases or sales to neighboring regions has not been a consideration within ERCOT, which is very weakly interconnected with other regions. If transmission projects will be evaluated in the future that may increase exports from or into ERCOT, the system-wide production costs within ERCOT would need to be “adjusted” for such purchases and sales. This can be approximated through a widely-used benefit metric referred to as Adjusted Production Costs (APC).

Adjusted production costs for an individual utility are typically calculated as the sum of (1) the production costs of generating resources owned by or contracted to the utility, plus (2) the net cost of the utility’s market-based power purchases and sales. For example, APC for a utility is typically calculated as: (1) the production costs of generating resources owned by or contracted to the utility, plus (2) the cost of market-based power purchases valued at the simulated LMPs of the utility’s load locations (Load LMP), net of (3) the revenues from market-based power sales valued at the simulated LMP of the utility’s generation locations (Gen LMP).

cost simulations, one can quantify the direction and magnitude of both cost and price changes by comparing the results from the Change Case with those from the Base Case.

For example, SPP estimated that its Priorities Projects will result in \$1.3 billion of production cost savings. This amount of production cost savings is equal to approximately 62% of the estimated costs of the transmission projects that enable those savings.⁶³

2. Limitations of Production Cost Simulations and Estimated APC Savings

While production cost simulations are a valuable tool for estimating the economic value of transmission projects and have been used in the industry for many years, the specific practices continue to evolve. RTOs and transmission planners, including other system operators in Texas and neighboring regions, are increasingly recognizing that traditional production cost simulations are limited in their ability to estimate the full congestion relief and production cost benefits. These limitations, caused by necessary simplifications in assumptions and modeling approaches, tend to understate the likely future production cost savings associated with transmission projects. In most cases, the simplified market simulations assume:

- No change in transmission-related energy losses as a result of adding the proposed transmission project;
- No planned or unplanned transmission outages;
- No extreme contingencies, such as multiple or sustained generation and transmission outages;
- Weather-normalized peak loads and monthly energy (*i.e.*, no extreme weather conditions);
- Perfect foresight of all real-time market conditions;
- Incomplete plant cycling costs;
- Over-simplified modeling of ancillary service-related costs;
- Incomplete simulation of reliability must-run conditions;

In some cases, such as ERCOT's simulations undertaken for its long-term planning process, we also have observed that market simulations did not consider forced generation outages.

We discuss each of the common limitations listed above in Subsections 3 through 10, and provide examples of how the components of production cost savings that are not captured due to these simplifying assumptions can be or have been estimated.⁶⁴ Following that, Subsection 12 discusses how adjusted production cost calculations (if they were to be used by ERCOT in the future) simplify the estimated charges for congestion and marginal transmission losses, which can result in the under- or over-estimation of transmission-related benefits.

⁶³ SPP, 2010, p. 26.

⁶⁴ See *also ibid.*, Section 4.

3. Estimating Changes in Transmission Losses

In some cases, transmission additions or upgrades can reduce the energy losses incurred in the transmittal of power from generation sources to loads. However, due to significant increases in simulation run-times, a constant loss factor is typically provided as an input assumption into the production cost simulations. This approach ignores that the transmission investment may reduce the total quantity of energy that needs to be generated, thereby understating the production cost savings of transmission upgrades.

To properly account for changes in energy losses resulting from transmission additions will require either: (1) simulating changes in transmission losses; (2) running power flow models to estimate changes in transmission losses for the system peak and a selection of other hours; or (3) utilizing marginal loss charges (from production cost simulations with constant loss approximation) to estimate how the cost of transmission losses will likely change as a result of the transmission investment.⁶⁵ Through any of these approaches, the additional changes in production costs associated with changes in energy losses (if any) can be estimated.

In some cases, the economic benefits associated with reduced transmission losses can be surprisingly large, especially during system peak-load conditions. For instance, the energy cost savings of reduced energy losses associated with a 345 kV transmission project in Wisconsin were sufficient to offset roughly 30% of the project's investment costs.⁶⁶ Similarly, in the case of a proposed 765 kV transmission project, the present value of reduced system-wide losses was estimated to be equal to roughly half of the project's cost.⁶⁷ For transmission projects that specifically use advanced technologies that reduce energy losses, these benefits are particularly important to capture. For example, a recent analysis of a proposed 765 kV project using "low-loss transmission" technology showed that this would provide an additional \$11 to 29 million in annual savings compared to the older technology.⁶⁸

4. Estimating the Additional Benefits Associated with Transmission Outages

Production cost simulations typically consider planned generation outages and, in most cases, a random distribution of unplanned generation outages. In contrast, they do not generally reflect *transmission* outages, planned or unplanned. Both generation and transmission outages can have significant impacts on transmission congestion and production costs. By assuming that transmission facilities are available 100% of the time, the analyses tend to under-estimate the

⁶⁵ For a discussion of estimating loss-related production cost savings from the marginal loss results of production cost simulations see *ibid.*, Section 4.2. See also Pfeifenberger Direct Testimony, 2008.

⁶⁶ ATC, 2007, pp. 4 (project cost) and 63 (losses benefit).

⁶⁷ Pioneer, 2009, at p. 7. These benefits include not only the energy value (*i.e.*, production cost savings) but also the capacity value of reduced losses during system peak.

⁶⁸ Pfeifenberger and Newell Direct Testimony, 2011.

value of transmission upgrades and additions because outages, when they occur, typically cause transmission constraints to bind more frequently and increase transmission congestion and the associated production costs significantly.⁶⁹

Transmission outages account for a significant and increasing portion of real-world congestion. For example, when the PJM FTR Task Force reported a \$260 million FTR congestion revenue inadequacy (or approximately 18% of total PJM congestion revenues during the 2010–11 operating year), approximately 70% of this revenue inadequacy was due to major construction-related transmission outages (16%), maintenance outages (44%), and unforeseen transmission de-ratings or forced outages (9%). In fact, the frequency of PJM transmission facility rating reductions due to transmission outages has increased from approximately 500 per year in 2007 to over 2,000 in 2012.⁷⁰ Similarly, while the exact amount attributable to transmission outages is not specified, the Midwest ISO's independent market monitor noted that congestion costs in the day-ahead and real-time markets in 2010 rose 54 percent to nearly \$500 million due to higher loads and transmission outages.⁷¹ MISO also recently addressed the challenge of FTR revenue inadequacy by using a representation of the transmission system in its simultaneous FTR feasibility modeling that incorporates planned outages and a derate of flowgate capacity to account for unmodeled events such as unplanned transmission outages and loop flows.⁷² As aging transmission facilities need to be rebuilt, the magnitude and impact of transmission outages will only increase.

A 2005 study of PJM assessed the impact of transmission outages. That analysis showed that without transmission outages, total PJM congestion charges would have been 20% lower; the value of FTRs from the AEP Generation Hub to the PJM Eastern Hub would have been 37% lower; the value of FTRs into Atlantic Electric, for example, would have been more than 50% lower; and that simulations without outages generally understated prices in eastern PJM and west-east price differentials.⁷³ These examples show that real-world congestion costs are higher than congestion costs in a world without transmission outages. This means that the typical production cost simulations, which do not consider transmission outages, tend to understate the

⁶⁹ For an additional discussion of simulating the transmission outage mitigation value of transmission investments, see SPP, 2010, Section 4.3.

Also note that, while not related to production costs, the transmission outages can also result in reduced system flexibility that can delay certain maintenance activities (because maintenance activities could require further line outages), which in turn can reduce network reliability.

⁷⁰ PJM FTR Report 2012, p. 32. See also PJM FTR Presentation, 2011.

⁷¹ Patton, 2011.

⁷² See Section 7.1 (Simultaneous Feasibility Test) of the MISO Business Practices Manuals. Posted at: <https://www.midwestiso.org/LIBRARY/BUSINESSPRACTICESMANUALS/Pages/BusinessPracticesManuals.aspx>.

⁷³ Pfeifenberger and Newell, 2006.

extent of congestion on the system and, as a result, the congestion-relief benefit provided by transmission upgrades.

Production cost simulations can be augmented to reflect reasonable levels of outages, either by building a data set of a normalized outage schedule (not including extreme events) that can be introduced into simulations or by reducing the limits that will induce system constraints more frequently. For the RITELine transmission project, specific production cost benefits were analyzed for the planned outages of four existing high-voltage lines. It was found that a one-week (non-simultaneous) outage for each of the four existing lines increased the production cost benefits of the RITELine project by more than \$10 million a year, with PJM's Load locational pricing payments decreasing by more than \$40 million a year. Because there are several hundred high-voltage transmission elements in the region of the proposed RITELine, the actual transmission-outage-related savings can be expected to be significantly larger than the simulated savings for the four lines examined in that analysis.⁷⁴

Our ongoing work for SPP indicates that applying the most important transmission outages from the last year to forward-looking simulations of transmission investments increases the estimates of adjusted production cost savings by approximately 10% to 15% even under normalized system (*e.g.*, peak load) conditions.⁷⁵ Higher additional transmission-outage-related savings are expected in portions of the grid that already have very limited operating flexibility and during challenging (*i.e.*, not normalized) system conditions.

The fact that transmission outages increase congestion and associated production costs is also documented for non-RTO regions. For example, Entergy's Transmission Service Monitor (TSM) found that transmission constraints existed during 80% of all hours, leading to 331 curtailments of transmission services, at least some of which was the result of the more than 2,000 transmission outages that affected available transmission capability during a three month period.⁷⁶ The TSM report also showed that, for the five most constrained flowgates on the Entergy system, the available flowgate capacity during real-time operations generally fluctuated by several hundred MW over time. This means that the actual available transmission capacity is less on average than the limits used in the market simulation models, which assume a constant transmission capability equal to the flowgate limits used for planning purposes. This also indicates that the traditional simulations tend to understate transmission congestion by not reflecting the lower transmission limits in real-time. The TSM report also stated that the identified transmission constraints resulted in the refusal of transmission service requests for approximately 1.2 million MWh during the same three month period.

⁷⁴ Pfeifenberger and Newell Direct Testimony, 2011.

⁷⁵ Pfeifenberger, *et al.*, 2013.

⁷⁶ Potomac Economics (2013).

These examples show that real-world congestion costs are higher than the congestion costs simulated through traditional production cost modeling that assumes a world without transmission outages. These values associated with new transmission's ability to mitigate the cost of transmission outages will be particularly relevant in areas of the grid with constrained import capability and limited system flexibility.

5. Estimating the Benefits of Mitigating the Impacts of Extreme Events and System Contingencies

Transmission upgrades can provide insurance against extreme events, such as unusual weather conditions, fuel shortages, and multiple or sustained generation and transmission outages. Even if a range of typical generation and transmission outage scenarios are simulated during analyses of proposed projects, production cost simulations will not capture the impacts of extreme events; nor will they capture how proposed transmission investments can mitigate the potentially high costs resulting from these events. Although extreme events occur very infrequently, when they do they can significantly reduce the reliability of the system, induce load shed events, and impose high emergency power costs. Production cost savings from having a more robust transmission system under these circumstances include the reduction of high-cost generation and emergency procurements necessary to support the system. Additional economic value (discussed further below) includes the value of avoided load shed events.

The insurance value of additional transmission in reducing the impact of extreme events can be significant, despite the relatively low likelihood of occurrence. While the value of increased system flexibility during extreme contingencies is difficult to estimate, system operators intrinsically know that increased system flexibility provides significant value. One approach to estimate these additional values is to use extreme historical market conditions and calculate the probability-weighted production cost benefits through simulations of the selected extreme events. For example, a production cost simulation analysis of the insurance benefits for the Paddock-Rockdale 345 kV transmission project in Wisconsin found that the project's probability-weighted savings from reducing the production and power purchase costs during a number of simulated extreme events (such as multiple transmission or nuclear plant outages similar to actual events that occurred in prior years) added as much as \$28 million to the production cost savings, offsetting 20% of total project costs.⁷⁷

For the PVD2 project, several contingency events were modeled to determine the value of the line during these high-impact, low-probability events. The events included the loss of major transmission lines and the loss of the San Onofre nuclear plant. The analysis found significant benefits, including a 61% increase in energy benefits, to CAISO ratepayers in the case of the San

⁷⁷ ATC, 2007, pp. 4 (project cost) and 50-53 (insurance benefit).

Onofre outage.⁷⁸ This simulated high-impact, low-probability event turned out to be quite real, as the San Onofre nuclear plant has been out of service since early 2012 and will now be closed permanently.⁷⁹

Further, the analysis of high-impact, low-probability events also documented that—while the estimated societal benefit (including competitive benefit) of the PVD2 line was only \$77 million for 2013—there was a 10% probability that the annual benefit would exceed \$190 million under various combinations of higher-than-normal load, higher-than-base-case gas prices, lower-than-normal hydro generation, and the benefits of increased competition. There was also a 4.8% probability that the annual benefit ranged between \$360 and \$517 million.⁸⁰

6. Estimating the Benefits of Mitigating Weather and Load Uncertainty

Production cost simulations are typically performed for all hours of the year, though the load profiles used typically reflect only normalized monthly and peak load conditions. Such methodology does not fully consider the regional and sub-regional load variances that will occur due to changing weather patterns and ignores the potential benefit of transmission expansions when the system experiences higher-than-normal load conditions or significant shifts in regional weather patterns that change the relative power consumption levels across multiple regions or sub-regions. For example, a heat wave in the southern portion of a region, combined with relatively cool summer weather in the north, could create much greater power flows from the north to the south than what is experienced under the simulated normalized load conditions. Such greater power flows would create more transmission congestion and greater production costs. In these situations, transmission upgrades would be more valuable if they increased the transfer capability from the cooler to hotter regions.⁸¹

SPP's Metrics Task Force recently suggested that SPP's production simulations should be developed and tested for load profiles that represent 90/10 and 10/90 peak load conditions—rather than just for base case simulations (reflecting 50/50 peak load conditions)—as well as scenarios reflecting north-south differences in weather patterns.⁸² Such simulations may help analyze the potential incremental value of transmission projects during different load conditions. While it is difficult to estimate how often such conditions might occur in the future, they do

⁷⁸ CPUC *Opinion*, 2007, pp. 37–41.

⁷⁹ See Wald, 2013.

⁸⁰ CAISO PVD2 Report, 2005, p. 24.

⁸¹ Because the incremental system costs associated with higher-than-normal loads tend to exceed the decremental system costs of lower-than-normal loads, the probability-weighted average production costs across the full spectrum of load conditions tend to be above the production costs for normalized conditions.

⁸² See SPP, 2012, Section 9.6.

occur, and ignoring them disregards the additional value that transmission projects provide under these circumstances. For example, simulations performed by ERCOT for normal loads, higher-than-normal loads, and lower-than-normal loads in its evaluation of a Houston Import Project showed a \$45.3 million annual consumer benefit for the base case simulation (normal load) compared to a \$57.8 million probability-weighted average of benefits for all three simulated load conditions.⁸³

7. Estimating the Impacts of Imperfect Foresight of Real-Time System Conditions

Another simplification inherent in traditional production cost simulations is the deterministic nature of the models that assumes perfect foresight of all real-time system conditions. Assuming that system operators know exactly how real-time conditions will materialize when system operators must commit generation units in the day-ahead market means that the impact of many real-world uncertainties are not captured in the simulations. Changes in the forecasted load conditions, intermittent resource generation, or plant outages can significantly change the transmission congestion and production costs that are incurred due to these uncertainties.

Uncertainties associated with load, generation, and outages can impose additional costs during unexpected real-time conditions, including over-generation conditions that impose additional congestion costs. For example, comparing the number of negatively priced hours in the real-time versus the day-ahead markets in the ComEd load zone of PJM provides an example of how dramatically load and intermittent resource conditions can change.⁸⁴ From 2008 to 2010, there were 763 negatively priced hours in the real-time market, but only 99 negatively priced hours in the day-ahead market. The increase in negative prices in the real-time, relative to the day-ahead, market is due to the combined effects of lower-than-anticipated loads with the significantly higher-than-predicted output of intermittent wind resources. While this example illustrates the impact of uncertainties within the day-ahead time frame, traditional production cost simulations do not consider these uncertainties and their impacts.

Thus, to estimate the additional benefits that transmission upgrades can provide with the uncertainties associated with actual real-time system conditions, traditional production cost simulations need to be supplemented. For example, existing tools can be modified so that they simulate one set of load and generation conditions anticipated during the time that the system operators must commit the resources, and another set of load and generation conditions during real-time. The potential benefits of transmission investments also extend to uncertainties that need to be addressed through intra-hour system operations, including the reduced quantities and

⁸³ ERCOT, 2011a, p. 10. The \$57.8 million probability-weighted estimate is calculated based on ERCOT's simulation results for three load scenarios and Luminant's estimated probabilities for the same scenarios.

⁸⁴ Pfeifenberger and Newell Direct Testimony, 2011.

prices for ancillary services (such as regulation and spinning reserves) needed to balance the system as discussed further below.⁸⁵ These benefits will generally be more significant if transmission investments allow for increased diversification of uncertainties across the region, or if the investments increase transmission capabilities between renewables-rich areas and resources in the rest of the grid that can be used to balance variances in renewable generation output.⁸⁶

8. Estimating the Additional Benefits of Reducing the Frequency and Cost of Cycling Power Plants

With increased power production from intermittent renewable resources, some conventional generation units may be required to operate at their minimum operating levels and cycle up and down more frequently to accommodate the variability of intermittent resources on the system. Additional cycling of plants can be particularly pronounced when considering the uncertainties related to renewable generation that can lead to over-commitment and over-generation conditions during low loads periods. Such uncertainty-related over-generation conditions lead to excessive up/down and on/off cycling of generating units. The increased cycling of aging generating units may reduce their reliability, and the generating plants that are asked to shut down during off-peak hours may not be available for the following morning ramp and peak load periods, reducing the operational flexibility of the system. Some of these operational issues could reduce resource adequacy and increase market prices when the system must dispatch higher-cost resources.

Transmission investments can provide benefits by reducing the need for cycling fossil fuel power plants by spreading the impact of intermittent generation across a wider geographic region. Such projects provide access to a broader market and a wider set of generation plants to respond to the changes in generation output of renewable generation.

The cost savings associated with the reduction in plant cycling would vary across plants. A recent study of power plants in the Western U.S. found that increased cycling can increase the plants' maintenance costs and forced outage rates, accelerate heat rate deterioration, and reduce the lifespan of critical equipment and the generating plant overall. The study estimated that the total hot-start costs for a conventional 500 MW coal unit are about \$200/MW per start (with a

⁸⁵ For example, a recent study for the National Renewable Energy Laboratory (NREL) concluded that, with 20% to 30% wind energy penetration levels for the Eastern Interconnection and assuming substantial transmission expansions and balancing-area consolidation, total system operational costs caused by wind variability and uncertainty range from \$5.77 to \$8.00 per MWh of wind energy injected. The day-ahead wind forecast error contributes between \$2.26/MWh and \$2.84/MWh, while within-day variability accounts for \$2.93/MWh to \$5.74/MWh of wind energy injected. See EnerNex, 2013 (\$/MWh in US\$2024).

⁸⁶ For a simplified framework to consider both short-term and long-term uncertainties in the context of transmission and renewable generation investments, see Munoz, *et al.*, 2013; Van Der Weijde and Hobbs, 2012; and Park and Baldick, 2013.

range between \$160/MW and \$260/MW). The costs associated with equipment damage account for more than 80% of this total.⁸⁷

Production cost simulations can be used to measure the impact of transmission investments on the frequency and cost of cycling fossil fuel power plants. However, the simplified representation of plant cycling costs in traditional production cost simulations—in combination with deterministic modeling that does not reflect many real-world uncertainties—will not fully capture the cycling-related benefits of transmission investments. Although SPP’s Metrics Task Force recently suggested that production simulations be developed and tested,⁸⁸ this is an area where standard analytical methodology still needs to be developed.

9. Estimating the Additional Benefits of Reduced Amounts of Operating Reserves

Traditional production cost simulations assume that a fixed amount of operating reserves is required throughout the year, irrespective of transmission investments. Most market simulations set aside generation capacity for spinning reserves; regulation-up requirements may be added to that. Regulation-down requirements and non-spinning reserves are not typically considered. Such simplifications will understate the costs or benefits associated with any changes in ancillary service requirements. The analyses typically disregard the costs that integrating additional renewable resources may impose on the system or the potential benefits that transmission facilities can offer by reducing the quantity of ancillary services required. Such costs and benefits will become more important with the growth of variable renewable generation.

The estimation of these benefits consequently requires an analysis of the quantity and types of ancillary services at various levels of intermittent renewable generation, with and without the contemplated transmission investments. The Midwest ISO recently performed such an analysis, finding that its portfolio of multi-value transmission projects reduced the amount of operating reserves that would have to be held within individual zones, which allowed reserves to be sourced from the most economic locations. MISO estimated that this benefit was very modest, with a present value of \$28 to \$87 million, or less than one percent of the cost of the transmission projects evaluated.⁸⁹ In other circumstances, where transmission can interconnect regions that require additional supply of ancillary services with regions rich in resources that can provide ancillary services at relatively low costs (such as certain hydro-rich regions), these savings may

⁸⁷ See Kumar, *et al.*, 2012. The study is based on a bottom-up analysis of individual maintenance orders and failure events related to cycling operations, combined with a top-down statistical analysis of the relationship between cycling operations and overall maintenance costs. See *Id.* (2011), p. 14. Costs inflated from \$2008 to \$2012. Note that the Intertek-APTECH’s 2012 study prepared for NREL (Kumar, *et al.*, 2012) reported only ‘lower-bound’ estimates to the public.

⁸⁸ SPP, 2012, Section 9.4.

⁸⁹ MISO, 2011, pp. 29-33.

be significantly larger. However, to quantify these benefits often requires specialized simulation tools that can simulate both the impacts of imperfect foresight and the costs of intra-hour load following and regulation requirements. Most production cost simulations are limited to simulating market conditions with perfect foresight and on an hourly basis.

Finally, a number of organized power markets do not co-optimize the dispatch of energy and ancillary services resources. Other regions with co-optimized markets may still require some location-specific unit commitment to provide ancillary services. If not considered in market simulations, this can understate the potential benefits associated with transmission-related congestion relief.

10. Estimating the Benefits of Mitigating Reliability Must-Run Conditions

Traditional production cost simulation models determine unit commitment and dispatch based on first contingency transmission constraints, utilizing a simple direct current (DC) power-flow model. This means that the simulation models will not by themselves be able to determine the extent to which generation plants would need to be committed for certain local reliability considerations, such as for system stability and voltage support and to avoid loss of load under second system contingencies. Instead, any such “reliability must run” (RMR) conditions must be identified and implemented as a specific simulation input assumption. Both existing RMR requirements and the reduction in these RMR conditions as a consequence of transmission upgrades need to be determined and provided as a modeling input separately for the Base Case and Change Case simulations.

RMR-related production cost savings provided by transmission investments can be significant. For example, a recent analysis of transmission upgrades into the New Orleans region shows that certain transmission projects would significantly alleviate the need for RMR commitments of several local generators. Replacing the higher production costs from these local RMR resources with the market-based dispatch of lower-cost resources resulted in estimated annual production cost savings ranging from approximately \$50 million to \$100 million per year.⁹⁰ Avoiding or eliminating a set of pre-existing RMR requirements needed to be specified as model input assumptions.

11. Estimating Societal Benefits versus Electricity-Customer Savings

System-wide production cost savings from the simulations of transmission investments as discussed in this section represent economy-wide societal benefits. In a regulatory environment where all generation is cost-of-service regulated with no market-based purchases and off-system sales, these system-wide savings would also reflect customer benefits for the entire simulated

⁹⁰ Pfeifenberger Direct Testimony, 2012, pp. 48-49.

footprint—which usually includes all neighboring regions. To measure transmission-related benefits to an individual region, individual utilities, or other load-serving entities (LSEs), analysts typically rely on metrics such as Adjusted Production Costs (APC) and Load LMP costs. As noted above, these metrics can approximate electricity-customer benefits but they differ from the magnitude of societal benefits. The magnitude of these benefits depends on assumptions about market structure and the extent to which LSEs would be exposed to cost-based generation, market-based purchases and sales, and (within RTO markets) marginal loss charges and unhedged congestion charges.

For example, the APC metric measures the change in variable costs of generation within (or contracted to) an LSE's service area, adjusted for market-based purchases and sales. As a measure of customer impacts, the metric approximates customer costs for a vertically-integrated, cost-of-service regulated utility environment, consistent with simplifying assumptions that: (1) all owned or contracted resources supply power at variable production costs; (2) all imports and other non-cost-based purchases are market-based, priced at the area's internal Load LMP (*i.e.*, no fixed-priced contracts and assuming congestion charges for imports and purchases could not be hedged with allocated FTRs); (3) all off-system sales from an LSE's cost-based resources are priced at the area-internal Generation LMP; (4) no congestion costs charges are incurred in transmitting energy from cost-based generation to load within the LSE's service area (*i.e.*, all transactions from cost-based resources are fully hedged with allocated FTRs); and (5) no marginal loss charges are incurred on transactions from cost-based resources.

The load-weighted LMP metric measures the change in market-based power purchase costs that would be paid by customers in an LSE's service area if all load was served at LMPs at the load's location. This metric thus approximates customer impacts in a retail access environment, implicitly reflecting an assumption that all load is served at market prices without any cost-of-service-based generation, long-term contracts, FTR allocations that would hedge congestion charges, or the partial refunds of marginal-loss-related charges.

Because some RTO service areas cover both cost-of-service regulated, vertically-integrated utilities as well as LSEs that supply customers through market-based purchases, both APC and Load LMP metrics may be relevant. In fact, PJM has defined a blended metric based on a 70% APC and 30% Load-LMP weighted average. This hybrid metric roughly represents a market structure under which retail rates reflect roughly 70% cost-based generation that is fully hedged against congestion charges and 30% market-based generation (including imports) that is entirely unhedged through FTR allocations.⁹¹

⁹¹ MISO also previously used this hybrid (70%/30%) metric for production cost savings but has changed to a 100% Adjusted Production Cost Savings metric as they have found it better represents their load characteristics (MISO, 2012).

While these metrics and the simplifying assumptions used to derive them will be sufficient in many cases, a more accurate calculation of customer impacts for individual utilities or LSEs may be necessary because these traditional metrics do not explicitly take into account a number of energy and congestion-related factors that can be important in estimating the impacts of transmission investments from a customer-cost perspective. In particular, they may need to be modified to more accurately account for: (1) the degree of cost-based versus market-based generation; (2) long-term contracts and their pricing (*e.g.*, variable-cost based, fixed, or market-based); (3) the level of FTR coverage for a service area's internal and contracted generation; (4) the level of FTR coverage for imports into the service area; (5) the extent to which the transmission projects make additional FTRs available to LSEs in the service area; and (6) the difference between marginal loss charges, loss refunds, and the simulation's treatment of energy losses.⁹²

B. RELIABILITY AND RESOURCE ADEQUACY BENEFITS OF TRANSMISSION PROJECTS

This and the following subsections of this appendix address transmission-related benefits that are not reflected in production cost savings. As noted earlier, production cost savings only measure the reduction in variable production costs, including fuel, variable O&M costs, and emission costs.⁹³ This means that production cost savings, even if the simulations capture the additional factors discussed above, will not capture the benefits associated with reliability, capital costs, increased competition, certain environmental benefits and other public policy benefits, or economic development benefits. These benefits provide additional value to electricity customers and to the economy as a whole.

Transmission investments will generally increase the reliability of the electric power system even when meeting reliability standards is not the primary purpose of the line. For example, additional transmission investment made for market efficiency and public policy goals can avoid or defer reliability upgrades that would otherwise be necessary, increase operating flexibility, reduce the risk of load shed events, and increase options for recovering from supply disruptions. This increase in reliability provides economic value by reducing the frequency, duration, and magnitude of load curtailments—or, alternatively, by reducing the planning reserve margins needed to maintain resource adequacy targets, such as a 1-day-in-10-year loss of load probability. These reliability benefits are not captured in production cost simulations, but can be estimated separately. Below we describe the categories of reliability and resource adequacy benefits.

⁹² For an example of more detailed estimates of customer impacts, see Pfeifenberger Direct Testimony, 2008.

⁹³ Emissions costs are only considered to the extent that the simulations assume a price for emissions such as SO₂, NO_x, and in some cases CO₂.

1. Benefits from Avoided or Deferred Reliability Projects

When certain transmission projects are proposed for economic or public policy reasons, transmission upgrades that would otherwise have to be made to address reliability needs may be avoided or could be deferred for a number of years. As is already largely reflected in ERCOT's planning process, these avoided or deferred reliability upgrades effectively reduce the net cost of planned economic or public-policy projects. The long-term benefits can be estimated by comparing over time the revenue requirements of reliability-based transmission upgrades without the proposed project (the Base Case) to the lower revenue requirements reflecting the avoided or delayed reliability-based upgrades assuming the proposed project would be in place (the Change Case). The present value of the difference in revenue requirements for the reliability projects (including the trajectory of when they are likely to be installed) represents the estimated value of avoiding or deferring certain projects. If the avoided or deferred projects can be identified, then the avoided costs associated with these projects can be counted as a benefit (*i.e.*, cost savings) associated with the proposed new projects.

SPP, for example, uses this method to analyze whether potential reliability upgrades could be deferred or replaced by proposed new economic transmission projects.⁹⁴ Similarly, a recent projection of deferred transmission upgrades for a potential portfolio of transmission lines considered by ITC in the Entergy region found the reduction in the present value of reliability project revenue requirements to be \$357 million, or 25% of the costs of the proposed new transmission projects.⁹⁵ This method has also been used by MISO, who found that the proposed MVP projects would increase the system's overall reliability and decrease the need for future baseline reliability upgrades. In fact, MISO's MVP projects were found to eliminate future transmission investments of one bus tie, two transformers, 131 miles of transmission operating at less than 345 kV, and 29 miles of 345 kV transmission.⁹⁶

2. Benefits of Reduced Loss of Load Probability or Reduced Planning Reserve Margin Requirements

Even if not targeted to address identified reliability needs, transmission investments can reduce the frequency and severity of necessary load curtailments by providing additional pathways for connecting generation resources with load in regions that can be constrained by weather events and unplanned outages. From a risk mitigation perspective, transmission projects provide insurance value to the system such that when contingencies, emergencies, and extreme market conditions stress the system, having a more robust grid would reduce: (1) the need to rely on higher-cost measures to avoid shedding load (a production cost benefit considered in the

⁹⁴ See SPP, 2012, Section 3.3.

⁹⁵ Pfeifenberger Direct Testimony, 2012, pp. 77-78.

⁹⁶ MISO, 2011, pp. 42-44.

previous section of this paper); and (2) the likelihood of load shed events, thus improving physical reliability.

As recognized by SPP's Metrics Task Force, for example, such reliability benefits can be estimated through Monte Carlo simulations of systems under a wide range of load and outage conditions to obtain loss-of-load related reliability metrics, such as Loss of Load Hours (LOLH), Loss of Load Expectation (LOLE), and Expected Unserved Energy (EUE).⁹⁷ The reliability benefit of transmission investments can be estimated by multiplying the estimated reduction in EUE (in MWh) by the customer-weighted average Value of Lost Load (VOLL, in \$/MWh). Estimates of the average VOLL can exceed \$5,000 to \$10,000 per curtailed MWh. The high value of lost load means that avoiding even a single reliability event that would have resulted in a blackout would be worth tens of millions to billions of dollars. As ATC notes, for example, had its Arrowhead-Weston line been built earlier, it would have reduced the impact of blackouts in the region.⁹⁸

When a transmission investment reduces the loss of load probabilities, system operators may be able to reduce their resource adequacy requirements, in terms of the system-wide required planning reserve margin or the required reserve margins within individual resource adequacy zones of the region. If system operators choose to reduce resource adequacy requirements, the benefit associated with such reduction can be measured in terms of the reduced capital cost of generation. Effectively, the reduced cost would be estimated by calculating the difference in the cost of generation needed under the required reserve margins before adding the new transmission projects versus the cost of generation with the lower required reserve margins after adding the new transmission. Transmission investments tend to either reduce loss-of-load events (if the planning reserve margin is unchanged) or allow for the reduction in planning reserve margins (if holding loss-of-load events constant), but not both simultaneously.⁹⁹

The potential for transmission investments to reduce the reserve margin requirement has been recognized by a number of system operators. MISO recently estimated through LOLE reliability simulations that its MVP portfolio is expected to reduce required planning reserve margins by up to one percentage point. Such reduction in planning reserves translated into reduced generation capital investment needs ranging from \$1.0 billion to \$5.1 billion in present value terms,

⁹⁷ SPP, 2012, Section 5.2.

LOLH measures the expected number of hours in which load shedding will occur. LOLE is a metric that accounts for the expected number of days, hours, or events during which load needs to be shed due to generation shortages. And EUE is calculated as the probability-weighted MWh of load that would be unserved during loss-of-load events.

⁹⁸ ATC, 2009.

⁹⁹ This is due to the overlap between the benefit obtained from a reduction in reserve margin requirements and the benefit associated with a reduced loss-of-load probability (if the reserve margin requirement is not adjusted). Only one of these benefits is typically realized.

accounting for 10–30% of total MVP project costs.¹⁰⁰ This benefit was similarly recognized by the SPP Metrics Task Force,¹⁰¹ as well as by the Public Service Commission of Wisconsin, which noted that “the addition of new transmission capacity strengthening Wisconsin's interstate connections” was one of three factors that allowed it to reduce the planning reserve margin requirements of Wisconsin utilities from 18% to 14.5%.¹⁰²

C. GENERATION INVESTMENT COST SAVINGS

Transmission investments can also reduce generation investment costs beyond those related to increasing the reliability benefits and reduced reserve margin requirements. Transmission upgrades can also reduce generation capacity costs in the form of: (1) lowering generation investment needs by reducing losses during peak load conditions; (2) delaying needed new generation investment by allowing for additional imports from neighboring regions with surplus capacity; and (3) providing the infrastructure that allows for the development and integration of lower-cost generation resources. Below, we discuss each of these three societal benefits.

1. Generation Investment Cost Benefits from Reduced Transmission Losses

Investments in transmission often reduce generation investment needs by reducing system-wide energy losses during peak load conditions. This benefit is in addition to the production cost savings associated with reduced energy losses. During peak hours, a reduction in energy losses will reduce the additional generation capacity needed to meet the peak load, transmission losses, and reserve margin requirements. For example, in a system with a 15% planning reserve margin, a 100 MW reduction in peak-hour losses will reduce installed generating capacity needs by 115 MW.

The economic value of reduced losses during peak system conditions can be estimated through calculating the capital cost savings associated with the reduction in installed generation requirements. These capital cost savings can be calculated by multiplying the estimated net cost of new entry (Net CONE), which is the cost of new generating capacity net of operating margins earned in energy and ancillary services markets when the region is resource-constrained, with the reduction in installed capacity requirements.¹⁰³

¹⁰⁰ MISO, 2011, pp. 34-36.

¹⁰¹ SPP, 2012, Section 5.1.

¹⁰² PSC WI, 2008, p. 5. Two other changes that contributed to this decision were the introduction of the Midwest ISO as a security constrained independent dispatcher of electricity and the development of additional generation in the state.

¹⁰³ Net CONE is an estimate of the annualized fixed cost of a new natural gas plant, net of its energy and ancillary service market profits. Fixed costs include both the recovery of the initial investment as well as the ongoing fixed operating costs of a new plant. This is an estimate of the capacity price that a utility or

Several planning regions have estimated the capacity cost savings associated with loss reductions due to transmission investments:

- SPP’s evaluation of its Priority Projects showed \$71 million in capacity savings from reduced losses, or 3% of total project costs.¹⁰⁴
- ATC found that its Paddock-Rockdale project provided an estimated \$15 million in capacity savings benefits from reduced losses, or approximately 10% of total project costs.¹⁰⁵
- MISO also found that its MVP portfolio reduced transmission losses during system peak by approximately 150 MW, thereby reducing the need for future generation investments with a present value benefit in the range of \$111 to \$396 million, offsetting 1–2% of project costs.¹⁰⁶
- An analysis of potential transmission projects in the Entergy footprint showed that the projects could reduce peak-period transmission losses by 32 MW to 49 MW, offering a benefit of approximately \$50 million in reduced generating investment costs, offsetting approximately 2% of total project costs.¹⁰⁷

2. Deferred Generation Capacity Investments

Transmission projects can defer generation investment needs in resource-constrained areas by increasing the transfer capabilities from neighboring regions with surplus generation capacity. For example, an analysis for ITC of potential transmission projects in the Texas portion of Entergy’s service area showed that the transmission projects provide increased import capability from Louisiana and Arkansas. The imports allow surplus generating capacity in those regions to be delivered into Entergy’s resource-constrained Texas service area, thereby deferring the need for building additional local generation. By doing so, existing power plants that have the option to serve the Entergy Texas service area and the rest of Texas (the ERCOT region) would be able to serve the resource-constrained ERCOT region, thereby addressing ERCOT resource adequacy challenges. The economy-wide benefit of the deferred generation investments was estimated at \$320 million, about half of which was estimated to accrue to customers in Texas, with the other half of the benefit to accrue to merchant generators in Louisiana and Arkansas.¹⁰⁸ A similar analysis also identified approximately \$400 million in resource adequacy benefits from deferred

other buyer would have to pay each year—in addition to the market price for energy—for a contract that could finance a new generating plant.

¹⁰⁴ SPP, 2010, p. 26.

¹⁰⁵ ATC, 2007, pp. 4 (project cost) and 63 (capacity savings from reduced losses).

¹⁰⁶ MISO, 2011, pp. 25 and 27.

¹⁰⁷ Pfeifenberger Direct Testimony, 2012a, pp. 58-59.

¹⁰⁸ *Id.*, pp. 69.

generation investments associated with a transmission project that increases the transfer capability from Entergy's Arkansas and Louisiana footprint to TVA. These overall economy-wide benefits would accrue to a combination of TVA customers, Arkansas and Louisiana merchant generators, and, through increased MISO wheeling-out revenues, Entergy and other MISO transmission customers.

3. Access to Lower-Cost Generating Resources

Some transmission investments increase access to generation resources located in low-cost areas. Generation developed in these areas may be low cost due to low permitting costs, low-cost sites on which plants can be built (*e.g.*, low-cost land and/or sites with easy access to existing infrastructure), low labor costs, low fuel costs (*e.g.*, mine mouth coal plants and natural gas plants built in locations that offer unique cost advantages), access to valuable natural resources (*e.g.*, hydroelectric or pumped storage options), locations with high-quality renewable energy resources (*e.g.*, wind, solar, geothermal, biomass), or low environmental costs (*e.g.*, low-cost carbon sequestration and storage options).

While production cost simulations can capture cost savings from fuel and variable operating costs if the different locational choices are correctly reflected in the Base and Change Case simulations, the simulations would still not capture the lower overall generation investment costs. To the extent that transmission investments provide access to locations that offer generation options with lower capital costs, these benefits need to be estimated through separate analyses. At times, to accurately capture the production cost savings of such options may require that a different generation mix is specified in the production cost simulations for the Base Case (*e.g.*, with generation located in lower-quality or higher-cost locations) and the Change Case (*e.g.*, with more generation located in higher-quality or lower-cost locations).

The benefits from transmission investments that provide improved access to lower-cost generating resources can be significant from both an economy-wide and electricity customer perspective. For example, the CAISO found that the Palo Verde-Devers transmission project was providing an additional link between Arizona and California that would have allowed California resource adequacy requirements to be met through the development of lower-cost new generation in Arizona.¹⁰⁹ The capital cost savings were estimated at \$12 million per year from an economy-wide (*i.e.*, societal) perspective, or approximately 15% of the transmission project's cost, half of which it was assumed would accrue to California electricity customers. Similarly, ATC found that its Paddock-Rockdale transmission line enabled Wisconsin utilities to serve their growing load by building coal or IGCC generating capacity at mine-mouth coal sites in Illinois instead of building new plants in Wisconsin.¹¹⁰ The analysis found that sites in Illinois offered

¹⁰⁹ CAISO PVD2 Report, 2005, pp. 25-26.

¹¹⁰ ATC, 2007, pp. 54-55.

significantly lower fuel costs (or, in the future, potentially lower carbon sequestration costs) and that the transmission investment likely reduced the total cost of serving Wisconsin load compared to new resources developed within Wisconsin. In that instance, the analysis should have implemented different production cost assumptions in the Base and Change Cases to reflect the access to lower production cost generation with the new line compared to the status quo.

Access to a lower-cost generation option can also significantly reduce the cost of meeting public-policy requirements. For example, as discussed further under “public-policy benefits” in Subsection F below, the Midwest ISO evaluated different combinations of transmission investments and wind generation build-out options, ranging from low-quality wind locations that require less transmission investment to high-quality wind locations that require more transmission investment.¹¹¹ This analysis found that the total system costs could be significantly reduced through an optimized combination of transmission and wind generation investments that allowed a portion of total renewable energy needs to be met by wind generation in high-quality, low-cost locations. Similarly, the CREZ projects in Texas have also provided new opportunities for fossil generation plants to be located away from densely populated load centers where it may be difficult to find suitable sites for new generation facilities, where environmental limitations prevent the development of new plants, or where developing such generation is significantly more costly.

D. BENEFITS FROM INCREASED COMPETITION AND MARKET LIQUIDITY

Transmission projects can provide additional market benefits, both from an economy-wide and electricity customer rate perspective, by increasing competition in and the liquidity of wholesale power markets.

1. Benefits of Increased Competition

Production cost simulations generally assume that generation is bid into wholesale markets at its variable operating costs. This assumption does not consider that some bids will include mark-ups over variable costs, particularly in real-world wholesale power markets that are less than perfectly competitive. For this reason, the production cost and market price benefits associated with transmission investments could exceed the benefits quantified in cost-based simulations. This will be particularly true for transmission projects that expand access to broader geographic markets and allow more suppliers than otherwise to compete in the regional power market. Such effects are most pronounced during tight market conditions. Specifically, enlarging the market by transmission lines that increase transfer capability across multiple markets can decrease suppliers’ market power and reduce overall market concentration. The overall magnitude of benefits from increased competition can range widely, from a small fraction to multiples of the

¹¹¹ MISO, 2010, p. 32 and Appendix A.

simulated production cost savings, depending on: (1) the portion of load served by cost-of-service generation; (2) the generation mix and load obligations of market-based suppliers; and (3) the extent and effectiveness by which RTOs' market power mitigation rules yield competitive outcomes.

A lack of transmission to ensure competitive wholesale markets can be particularly costly to customers. For example, the Chair of the CAISO's Market Surveillance Committee estimated that if significant additional transmission capacity had been available during the California energy crisis from June 2000 to June 2001, electricity customer costs would have been reduced by up to \$30 billion over the 12 month period during which the crisis occurred.¹¹² More recently, ISO New England noted that increased transmission capacity into constrained areas such as Connecticut and Boston have significantly reduced congestion, "thereby significantly reducing the likelihood that resources in the submarkets could exercise market power."¹¹³

Given the experience during the California Power Crisis, the ability of transmission investment to increase competition in wholesale power markets has been considered explicitly in the CAISO's review of several proposed new transmission projects. For example, in its evaluation of the proposed Palo Verde-Devers transmission project, the CAISO noted that the "line will significantly augment the transmission infrastructure that is critical to support competitive wholesale energy markets for California consumers" and estimated that increased competition would provide \$28 million in additional annual consumer and "modified societal" benefits, offsetting approximately 40% of the annualized project costs.¹¹⁴ Similarly, in its evaluation of the Path 26 Upgrade transmission projects, the CAISO estimated the expected value of competitiveness benefits could offset up to 50 to 100% of the project costs, with a range depending on project costs and assumed future market conditions.¹¹⁵ A similar analysis was performed for ATC's Paddock-Rockdale line, estimating that the benefits of increased competition would offset between 10 to 40% of the project costs, depending on assumed market structure and supplier behavior.¹¹⁶

¹¹² CAISO TEAM Report, 2004, pp. ES-9.

¹¹³ FERC Performance Metrics, 2011, p. 106.

¹¹⁴ CAISO PVD2 Report, 2005, pp. 18 and 27. Under the "modified societal perspective" of the CAISO TEAM approach, producer benefits include net generator profits from competitive market conditions only. This modified societal perspective excludes generator profits due to uncompetitive market conditions.

¹¹⁵ CAISO TEAM Report, 2004 (using the proposed Path 26 upgrade as case study).

¹¹⁶ Pfeifenberger Direct Testimony, 2008; and ATC, 2007, pp. 44-47 and pp. 4 (project cost) and 63 (competitiveness benefit).

2. Benefits of Increased Market Liquidity

Limited liquidity in the wholesale electricity markets also imposes higher transaction costs and price uncertainty on both buyers and sellers. Transmission expansions can increase market liquidity by increasing the number of buyers and sellers able to transact with each other, which in turn will reduce the transaction costs (*e.g.*, bid-ask spreads) of bilateral transactions, increase pricing transparency, increase the efficiency of risk management, improve contracting, and provide better clarity for long-term planning and investment decisions.

Estimating the value of increased liquidity is challenging, but the benefits can be sizeable in terms of increased market efficiency and thus reduced economy-wide costs. For example, the bid-ask spreads for bilateral trades at less liquid hubs have been found to be between \$0.50 to \$1.50/MWh higher than the bid-ask spreads at more liquid hubs.¹¹⁷ At transaction volumes ranging from less than 10 million to over 100 million MWh per quarter at each of more than 30 electricity trading hubs in the U.S., even a \$0.10/MWh reduction of bid-ask spreads due to a transmission-investment-related increase in market liquidity would save \$4 million to \$40 million per year for a single trading hub, which would amount to a transactions cost savings of approximately \$500 million annually on a nation-wide basis.

E. ENVIRONMENTAL BENEFITS

Depending on the effects of transmission expansions on the overall generation dispatch, some projects can reduce harmful emissions (*e.g.*, SO₂, NO_x, particulates, mercury, and greenhouse gases) by avoiding the dispatch of high-emission generation resources. The benefits of reduced emissions with a market pricing mechanism are largely calculated in production cost simulations for pollutants with emission prices such as SO₂ and NO_x. However, for pollutants that do not have a pricing mechanism yet, such as CO₂ in some regions, production cost simulations do not directly capture such environmental benefits unless specific assumptions about future emissions costs are incorporated into the simulations.

Not every proposed transmission project will necessarily provide environmental benefits. Some transmission investments can be environmentally neutral or even displace clean but more expensive generation (*e.g.*, displacing natural gas-fired generation when gas prices are high) with lower-cost but higher-emission generation. In some instances, a reduction in local emissions may be valuable (*e.g.*, reduced ozone and particulates) but not result in reduced regional (or national) emissions due to a cap and trade program that already limits the total of allowed emissions in the region. Nevertheless, even if specific transmission projects do not reduce the overall emissions, they may affect the costs of emissions allowances which in turn could affect the cost of delivered power to customers.

¹¹⁷ Pfeifenberger Oral Testimony, 2006, p. 39.

As more and more transmission projects are proposed to interconnect and better integrate renewable resources, some project proponents have quantified specific emissions reductions associated with those projects. For example, Southern California Edison estimated that the proposed Palo Verde-Devers No. 2 project would reduce annual NO_x emissions in WECC by approximately 390 tons and CO₂ emissions by about 360,000 tons per year. These emissions reductions were estimated to be worth in the range of \$1 million to 10 million per year.¹¹⁸ Similarly, an analysis of a portfolio of transmission projects in the Entergy service area estimated that the congestion and RMR relief provided by the projects would eliminate approximately one million tons of CO₂ emissions from fossil-fuel generators every year.¹¹⁹ That estimated emission reduction is equivalent to removing the annual CO₂ emissions from over 200,000 cars.

F. PUBLIC-POLICY BENEFITS

Some transmission projects can help regions reduce the cost of reaching public-policy goals, such as meeting the region's renewable energy targets by facilitating the integration of lower-cost renewable resources located in remote areas; while enlarging markets by interconnecting regions can also decrease a region's cost of balancing intermittent renewable resources.

As an illustration of these savings, transmission investments that allow the integration of wind generation in locations with a 40% average annual capacity factor can reduce the investment cost of wind generation by *one quarter* for the same amount of renewable energy produced compared to the investment costs of wind generation in locations with a 30% capacity factor.¹²⁰ Access to higher quality wind resources will reduce both economy-wide and electricity customer costs if the higher-quality wind resources can be integrated with additional transmission investment of less than the benefit, estimated to be \$500 to \$700 per kW of installed wind capacity.

As noted earlier, the Midwest ISO has assessed this benefit by evaluating different combinations of transmission investments and wind generation build-out options. The MISO analysis shows that the total cost of wind plants and transmission can be reduced from over \$110 billion for either all local or all regional wind resources to \$80 billion for a combination of local and regional wind development. The savings achieved from an optimized combination of local and regional wind and transmission investment would be over \$30 billion.¹²¹ These cost savings could be achieved by increasing the transmission investment per kW of wind generation from \$422/kW in the all-local-wind case to \$597/kW in the lowest-total-cost case.

¹¹⁸ CAISO PVD2 Report, 2005, pp. 26.

¹¹⁹ Pfeifenberger Direct Testimony, 2012, pp. 83.

¹²⁰ For example, see Burns & McDonnell, 2010, pp. 1–2, Figure 2.

¹²¹ MISO, 2010, p. 32 and Appendix A.

A similar analysis was also carried over into MISO's analysis of its portfolio of multi-value projects, which were targeted to help the Midwestern states meet their renewable energy goals. By facilitating the integration of high-quality wind resources, MISO found that its MVP portfolio reduced the present value of wind generation investments by between \$1.4 billion and \$2.5 billion, offsetting approximately 15% of the transmission project costs.¹²² Similarly, ATC found that its Arrowhead-Weston transmission project has the capability to deliver hydro resources from Canada and wind power from the Dakotas and interconnect local renewable generation to help meet Wisconsin's RPS requirement.¹²³

Additional transmission investment can also help reduce the cost associated with balancing intermittent resources. Interconnecting regions and expanding the grid allow a region to simultaneously access a more diverse set of intermittent resources than smaller systems. Such diversity would reduce the cost of balancing the system due to the "self-balancing" effect of generation output diversity and the larger pool of conventional resources that are available to compensate for the variable and uncertain nature of intermittent resources. The associated savings can be estimated in terms of the reduction of the balancing resources required (which is a fixed cost reduction) and a more efficient unit-commitment and system operations (which includes a variable cost reduction). If less generating capacity from conventional generation is needed, the reduction in capacity costs can be estimated using the Net Cost of New Entry. For the potential reduction in the operational costs associated with balancing renewable resources, if we assume that the renewable generation balancing benefit of an expanded regional grid reduces balancing costs by only \$1/MWh of wind generation, the annual savings associated with 10,000 MW of wind generation at 30% capacity factor would exceed \$25 million.

To summarize, even though making significant transmission investments to gain access to remotely-located renewable resources seems to increase the cost of delivering renewable generation, the savings associated with reducing the renewable generation costs (by obtaining access to high quality renewable resources), reducing the system balancing costs, and achieving other reliability and economic benefits can exceed the incremental cost of those transmission projects. In such cases, despite the fact that both transmission and retail electricity rates may increase, the transmission investment can reduce the overall cost of satisfying public policy goals.¹²⁴ While this rationale will not apply to every public-policy-driven transmission project, it

¹²² MISO, 2011, pp. 25 and 38-41.

¹²³ ATC, 2009, p. 7.

¹²⁴ In developing public policy goals, state or federal policy makers may have identified benefits inherent in the policies that are not necessarily economic or immediate. For the evaluation of public policy transmission projects, however, the objective is not be to assess the benefits and costs of the public policy goal, but the extent to which transmission investments can reduce the overall cost of meeting the public policy goal.

is instructive to consider these benefits and, if needed, estimate all potential benefits when evaluating large regional transmission investments.

G. EMPLOYMENT AND ECONOMIC STIMULUS BENEFITS

Transmission investments will also stimulate the local, regional, and national economy, supporting employment and regional economic activities. However, unlike the other economic benefits described above, the direct and indirect employment and economic stimulus associated with the construction and operations of the transmission system are benefits that do not reduce customer's electricity rates or improve their quality of service. These benefits are a measure of the effects of changes in power sector spending on other sectors in the economy, taking into account the input and output relationships among industries, consumers, and governments. For example, the construction of transmission facilities requires the use of labor and materials. Most of the manufacturing and construction activities will directly benefit the local economy by creating construction jobs. While certain input materials, such as towers and concrete, likely are sourced from within the region or from near-by regions, other materials such as cables and other electrical components may be imported from outside of the project's region or even from outside the U.S.

To measure the employment and overall economic activity supported by transmission investments, studies rely on a class of models known as input-output models.¹²⁵ Input-output models are universally used by economists and policy analysts to estimate how specified changes in spending affect every sector of a state's or region's economy.¹²⁶ Input-output models are

¹²⁵ Some of the studies did not utilize full input-output models but relied on the "economic multipliers" taken from these models. Nonetheless, the multipliers are consistent with input-output models and assumptions. Input-output models are based on detailed economic data on how goods and services are produced and consumed. An input-output model rebalances the overall economy after an increase in expenditures on particular types of products (e.g., construction activities and electric transmission equipment) such that the quantity produced equals the quantity consumed for every industry. These models specifically consider how much of the consumed products and services are supplied from each sector of a state or region.

¹²⁶ The majority of the studies we surveyed relied on the well-known and widely-used IMPLAN Model of the Minnesota IMPLAN Group (MIG) to estimate the employment and economic stimulus benefits of transmission investments. The IMPLAN (IMpact analysis for PLANning) economic impact modeling system is developed and maintained by MIG, which has continued the original work on the system done at the University of Minnesota in close partnership with the U.S. Forest Service's Land and Management Planning Unit. IMPLAN divides the economy into 440 sectors and allows the user to specify the expenditure allocations associated with a given expansion in demand to all relevant parts of the local economy in order to derive the economic impacts—changes in employment, earnings, and economic output. According to the U.S. Department of Agriculture, currently "over 1,500 clients across the country use the IMPLAN model, making the results acceptable in inter-agency analysis." In 2009, the U.S. Army Corps of Engineers Civil Works program utilized IMPLAN employment multipliers "to estimate the potential number of jobs preserved or created" by the American Recovery and Reinvestment Act of 2009. In addition, the U.S. Department of Commerce, the Bureau of Economic Analysis, the U.S. Department of Interior, the Bureau of Land Management, and the Federal Reserve System member banks are also among the agencies that utilize IMPLAN for economic impact analysis.

used to estimate: (1) the number of jobs supported in the region (in full-time-equivalent years or “FTE-years” of employment);¹²⁷ and (2) the economic activities generated in the region (*i.e.*, increased “economic output” as measured in total sales and resale revenues of businesses within the study region). Since these models report economic activity as the sum of the value of all goods and services sold at each level of the supply chain (*i.e.*, sales and resale revenues), the reported economic output refers to the total flow of money that occurs throughout the local economy. The measured impacts are the cumulative (undiscounted) number of jobs (or FTE-years of employment or FTE jobs each year), and the overall economic activity (in constant dollars) associated with investing in transmission projects over the entire construction phase.¹²⁸

It is important to note, however, that the employment and economic stimulus impacts associated with the construction and operation of the transmission system are not additive to the economic benefits accruing in the power sector. In addition, increasing or decreasing costs for electric customers or increasing or decreasing profits to the investors of generators will also have downstream employment and economic stimulus effects.

Our 2011 analysis conducted for WIRES shows that every \$1 billion of U.S. transmission investment directly and indirectly supports approximately 13,000 full-time-equivalent (FTE) years of employment and \$2.4 billion in total economic activity.¹²⁹ Approximately one-third of this employment benefit is associated with the direct construction and manufacturing of transmission facilities. Two-thirds of the total impact is associated with indirect and induced employment by suppliers and service providers to the transmission construction and equipment manufacturing sectors. As shown in Table 11, the WIRES report also summarized nine previous

¹²⁷ Employment impacts are generally reported as full-time-equivalent (FTE) job years, that is, 2,080 hours of full employment. For example, reporting 100 FTE years of employment could mean 200 full-time jobs supported for 6 months, 100 jobs supported for a year, or 10 jobs supported for 10 years.

¹²⁸ The employment and economic stimulus effects are typically quantified under three types of effects: “direct,” “indirect,” and “induced” impacts. Direct effects represent the changes in employment and economic activity in the industries which directly benefit from the investment (*i.e.*, construction companies, transmission materials and equipment manufacturing, and design services). Indirect effects measure the changes in the supply chain and inter-industry purchases generated from the transmission construction and manufacturing activities (*e.g.*, suppliers to transmission equipment manufacturers). Induced effects reflect the increased spending on food, clothing, and other services by those who are directly or indirectly employed in the construction of the transmission lines and substations. Employment supporting the three activities represents discrete net gains to the overall economy if the labor force is not being utilized elsewhere in the economy absent the projects. If the employment in a certain region is tight such that creating new jobs only allows people to change from less to more desirable jobs, very few new jobs would be created.

¹²⁹ Pfeifenberger and Hou, 2011.

studies of the employment and economic stimulus benefits of transmission investments, covering a wide range of regions in the U.S. as well as portions of Canada.¹³⁰

The summary shows that the local, state-level employment impacts range from a low of 2 FTE-years of total employment supported per million dollars of investment to a high of 18 FTE-years per million of investment (shown in Table 11 column [E]), with a majority of studies showing that each million dollars of transmission investment supports between 5 and 8 FTE-years of local employment. The economic output per million dollars of total transmission capital cost ranges from a low of \$0.2 million to \$2.9 million (shown in Table 11, column [F]).

In addition to employment and economic output, some studies also have estimated the increase in personal income earned by employees, local tax revenues, lease payments to local landowners, and stimulus to individual industries. While not all of the studies estimate these additional employment and economic stimulus benefits (and they cannot simply be added to other project benefits for the purpose of benefit-cost analyses as discussed in Section IV.B of this report), they nevertheless represent actual flows of wealth throughout a defined regional economy.

¹³⁰ There are several other studies discussing transmission-investment-related benefits to the regional or national economies, which are not included on our summary due to insufficient detail contained in or the different nature of these studies. For example, see Build Energy America!, 2011; McBride, *et al.*, 2008. More recent studies not summarized in the following discussion include: Perryman, 2010; Lewis and Pfister, 2010; and Lowe *et al.*, 2011.

Table 11
Employment and Economic Impacts of Transmission Investments
per Million Dollars of Total and Local Spending

Study Sponsor	Project Summary	% Local Spending	Based on Total Transmission Capital Cost			Based on Local Spending		
			FTE-Years of Employment Per \$ Million		Total Economic Output Per \$ Million	FTE-Years of Employment Per \$ Million		Total Economic Output Per \$ Million
			Direct	Total	(\$ Million)	Direct	Total	(\$ Million)
[A]	[B]	[C]	[D]	[E]	[F]	[G]	[H]	[I]
[1] AltaLink	AltaLink's estimated capital spending							
	Alberta	75%	5	7	N/A	7	9	N/A
	Rest of Canada Outside of Alberta	75%	N/A	3	N/A	N/A	3	N/A
[2] ATC LLC	Two completed projects							
	1. 138 kV Femrite-Sprecher	46%	N/A	5	\$0.7	N/A	11	\$1.5
	2. 345 kV Arrowhead-Weston	100%	N/A	8	\$1.4	N/A	8	\$1.4
[3] CapX2020	Five major transmission projects	100%	7	13	\$1.9	7	13	\$1.9
[4] Central Maine Power	Maine Power Reliability	81%	4	6	N/A	5	7	N/A
[5] Montana Department of Labor & Industry	Six major projects planned or under construction in Montana							
	1. Out-of-state contractors	11%	1	2	\$0.2	11	17	\$1.7
	2. In-state contractors	33%	2	5	\$0.6	7	14	\$1.7
	3. In- and out-of-state contractors	17%	2	3	\$0.3	9	16	\$1.7
[6] Perryman Group	CREZ transmission	100%	N/A	18	\$2.9	N/A	18	\$2.9
[7] South Dakota Wind Energy Association	Eastern South Dakota 345 kV transmission	25%	1	3	\$0.3	8	11	\$1.3
[8] SPP	Various Priority Projects							
	1. Group 1 - low in-region	47%	4	7	\$0.9	8	14	\$1.8
	2. Group 1 - high in-region	74%	5	8	\$1.3	6	11	\$1.7
	3. Group 2 - low in-region	47%	4	7	\$0.8	8	14	\$1.8
	4. Group 2 - high in-region	73%	5	8	\$1.2	6	11	\$1.7
[9] Wyoming Infrastructure Authority	Combination of 500 kV HVDC, 500 kV HVDC, and 230 kV HVAC	33%	5	5	\$0.4	14	15	\$1.3

Sources and Notes:

For full source citations, please refer to Table 3 in Pfeifenberger and Hou, 2011.

- [1]: "Rest of Canada Outside of Alberta" impacts reflect AltaLink's capital spending on other provinces. The study provided a value-added impact which is not reflected in the table above.
- [3]: Direct output assumed to be local spending.
- [4]: The study provided a value-added impact which is not reflected in the table above.
- [5]: Direct output assumed to be local spending.
- [6]: The study provided a value-added impact which is not reflected in the table above.
- [9]: NREL "direct" employment data have been adjusted by adding "indirect" impacts to align with other IMPLAN study definitions.

H. OTHER POTENTIAL PROJECT-SPECIFIC BENEFITS

Some transmission investments can create additional benefits that are very specific to the particular set of projects. These benefits may include improved storm hardening, increased load-serving capability, synergies with future transmission projects, the option value of large transmission facilities to improve future utilization of available transmission corridors, fuel diversity and resource planning flexibility, increased wheeling revenues, and the creation of additional physical or financial transmission rights to improve congestion hedging opportunities. Below, we discuss each briefly.

1. Storm Hardening

In regions that experience storm-induced transmission outages, certain transmission upgrades can improve the storm resilience of the existing grid transmission system. Strong storms that damage transmission lines can drastically affect an entire region where VOLL can be significantly large. Even if new transmission lines intended to increase system resilience are built along similar routes as existing transmission lines (and thus seemingly can be damaged by the same natural disasters), newer technologies and construction standards would allow the new projects to offer greater storm resilience than the existing transmission lines.¹³¹

2. Increased Load Serving Capability

A transmission project's ability to increase future load-serving capability ahead of specific transmission service requests is usually not considered when evaluating transmission benefits. For example, in regions experiencing significant load growth, the existing electric system often requires costly and possibly time-consuming system upgrades when a new industrial or commercial customer with a significant amount of load is contemplating locating in a utility's service area. At times, new transmission lines built to serve other needs (such as to increase market efficiency or to meet public-policy objectives) can also create low-cost options to quickly increase load-serving capability in the future.¹³²

3. Synergies with Future Transmission Projects

Certain transmission projects provide synergies with future transmission investments. For example, the building of the Tehachapi transmission project to access 4,500 MW of wind resources in the CAISO provides the option for a lower-cost upgrade of Path 26 than would otherwise be possible, as well as additional options for future transmission expansions in that

¹³¹ Pfeifenberger Direct Testimony, 2012, pp. 79–80.

¹³² For example, see *ibid.*, p. 80.

region.¹³³ Planning a set of “no-regrets” projects that will be needed under a wide range of future market conditions can help capitalize on such “option value.” For instance, the RITELine Project (spanning from western Illinois to Ohio) provides a “no regrets” step toward the creation of a larger regional transmission overlay that can integrate the substantial amount of renewable generation needed to meet the regional states’ RPS requirements over the next 10 to 20 years.¹³⁴ A number of regional planning efforts (such as RGOS I, RGOS II, and SMART) have shown that the expansion of renewable generation over the next 20 years may require construction of a Midwest-wide regional transmission overlay. The RITELine Project is an element common to the transmission configurations recommended in each of these larger regional transmission studies and, thus, in addition to the project’s standalone merit, creates the option of becoming an integrated part of such a regional overlay. Because the project is both valuable on a stand-alone basis and can be used as an element of the larger potential regional overlays, it can be seen as a first step that provides the option for future regional transmission buildout.

4. Up-Sizing Lines and Improved Utilization of Available Transmission Corridors

The number of right-of-way “corridors” on which new transmission lines can be built is often extremely limited, particularly in heavily populated or environmentally sensitive areas. As a result, constructing a new line on a particular right-of-way may limit or foreclose future options of building a higher-capacity line or additional lines. Foreclosing that option can turn out to be very costly. It will often be possible, however, to preserve this option or reduce the cost of foreclosing that option through the design of the transmission line that is planned and constructed now. For example, “upsizing” a transmission line ahead of actual need (*e.g.*, to a double-circuit or higher-voltage line) requires incremental investment but will greatly reduce the cost of foreclosing the option to increase capacity along the same corridor when additional transfer capability would be needed in the future. Similarly, the option to increase transmission capabilities in the future can be created, for example, by building a single-circuit line on double-circuit towers that create the option to add a second circuit in the future. Building a line rated for a higher voltage level than the voltage level at which it is initially operated (*e.g.*, building a line with 765kV equipment that is initially operated only at 345kV) creates the option to increase the transfer capability of the line at modest incremental costs in the future. While investing more today to create such low-cost options to “up-size” lines in the future may be valuable even without right-of-way limits, this option will be particularly valuable if finding additional rights-of-way would be very difficult or expensive.

¹³³ CAISO TEAM Report, 2004, pp. 9–21. Tehachapi region referred to as Kern County.

¹³⁴ Pfeifenberger and Newell Direct Testimony, 2011.

5. Increased Fuel Diversity and Resource Planning Flexibility

Transmission upgrades sometimes can help interconnect areas with very different resource mixes, thereby diversifying the fuel mix in the combined region and reducing price and production cost uncertainties. Projects also can provide resource planning flexibility by strengthening the regional power grid and lowering the cost of addressing future uncertainties, such as changes in the relative fuel costs, public policy objectives, coal plant retirements, or natural gas delivery constraints.

6. Benefits Related to Relieving Constraints in Fuel Markets

Additional transmission lines can provide benefits associated with relieving constraints in fuel markets. For example, recent reliability concerns in New England concerning gas-electric coordination issues caused by the increasing reliance on natural gas fired generation and limitations on pipeline capacity could be alleviated by additional import capacity for wholesale power from outside New England. In addition, increased diversity of generation resources enabled by new transmission lines can reduce the demand and price of fuel.¹³⁵

7. Increased Wheeling Revenues

A transmission line that increases exports (or wheeling through) of low-cost generation to a neighboring region can provide additional benefits to the exporting region's customers through increased wheeling out revenues. The increase in wheeling revenues, paid for by the exporting generator or importing buyer, will offset a portion of the transmission projects' revenue requirements, thus reducing the net costs to the region's own transmission customers. While not an economy-wide benefit, increasing wheeling revenues is equivalent to allocating some of the project costs to exporters and/or neighboring regions. For example, our analysis of an illustrative portfolio of transmission projects in the Entergy region estimated that approximately \$400 million of potential resource adequacy benefits were realized from deferred generation investment needs in the TVA service area by exporting additional amounts of surplus capacity from merchant generators in the Entergy region. While this is a benefit that accrues in large part to TVA customers and merchant generators in the Entergy region, approximately \$130 million of the \$400 million benefits accrue to Entergy and MISO customers in the form of additional MISO wheeling revenues after Entergy joins MISO, which partially offset the transmission projects' revenue requirements that would need to be recovered from Entergy/MISO customers and other market participants.¹³⁶

¹³⁵ Budhraj *et al.*, 2008, pp. 43-44.

¹³⁶ For example, see Pfeifenberger Direct Testimony, 2012, pp. 73-76.

8. Increased Transmission Rights and Customer Congestion-Hedging Value

A transmission project that increases transfer capabilities between lower-cost and higher-cost regions of the power grid can provide customer benefits by providing access in the form of increasing the availability of physical transmission rights in non-RTO markets or across RTO boundaries. Within RTOs and Day-2 markets such as ERCOT, the transmission upgrade would increase financial transmission rights that can be requested by and allocated to load-serving entities. The availability of additional FTRs increases the proportion of congestion charges that can be hedged by LSEs, thereby reducing congestion-related uncertainty. The additional FTRs can also reduce an area's customer costs (though not societal costs) by allowing imports from lower-cost portions of the region.¹³⁷ While a transmission upgrade may result in increased FTR revenues to LSEs from additional FTRs, the customer benefit of these additional revenues tends to be offset by revenue decreases from existing FTRs because the project will reduce congestion charges (and therefore reduce revenues from existing FTRs). For example, our analysis of the congestion and FTR-related impacts for the Paddock-Rockdale project in Wisconsin showed that these customer impacts can range widely—from increasing traditional APC estimates by approximately 50% in scenarios with low APC savings to decreasing traditional APC estimates by approximately 35% in scenarios with high APC savings.¹³⁸

9. Operational Benefits of High-Voltage Direct-Current Transmission Lines

The addition of high-voltage direct-current (“HVDC”) transmission lines can provide a range of operational benefits to system operators by enhancing reliability and reducing the cost of system operations. These operational benefits of HVDC lines, which in large part stem from the projects' new converter technologies, are broadly recognized in the industry. For example, various authors note that the technology can be used to: (1) provide dynamic voltage support to the AC system, thereby increasing its transfer capability;¹³⁹ (2) supply voltage and frequency support;¹⁴⁰ (3) improve transient stability¹⁴¹ and reactive performance;¹⁴² (4) provide AC system damping;¹⁴³ (5) serve as a “firewall” to limit the spread of system disturbances;¹⁴⁴ (6) “decouple”

¹³⁷ As noted earlier, this benefit is not captured in the traditional adjusted production cost (APC) and Load LMP metrics, because the metrics assume that all imports are priced at the load's location (*i.e.*, the area-internal Load LMP).

¹³⁸ Pfeifenberger Direct Testimony, 2008, Appendix A; and ATC, 2007, p. 63 (FTR and congestion).

¹³⁹ Bahrman (2008), p. 5.

¹⁴⁰ Wang, *et al.*, 2008, p. 19.

¹⁴¹ IEEE PES, 2005, p. 75.

¹⁴² As noted in several sources including: (1) UMD CIER, 2010, p. 51; (2) EWEA, 2009, p. 27; (3) Siemens, n.d.; and (4) Wright *et al.*, 2002, p. 5.

¹⁴³ IEEE PES, 2005, p. 75.

¹⁴⁴ Siemens, n.d.

the interconnected system so that faults and frequency variations between the wind farms and the AC network or between different parts of the AC network do not affect each other;¹⁴⁵ and (7) provide blackstart capability to re-energize a 100% blacked-out portion of the network.¹⁴⁶ For example, PJM recognized these benefits in its evaluation of the HVDC option for the Mid-Atlantic Power Pathway project.¹⁴⁷ It was also found that the proposed Atlantic Wind Connection HVDC submarine project's ability to redirect flow instantaneously will provide PJM with additional flexibility to address reliability challenges, system stability, voltage support, improved reactive performance, and blackstart capability.¹⁴⁸

¹⁴⁵ Lazaridis, 2005, p. 34.

¹⁴⁶ As noted in several sources including: (1) EWEA, 2009, p. 27; (2) Siemens, n.d.; (3) Lazaridis, 2005, p. 34; and (4) Wright *et al.*, 2002.

¹⁴⁷ PJM 2008 RTEP Update, pp. 8-10.

¹⁴⁸ Pfeifenberger and Newell Direct Testimony, 2010.

APPENDIX C – OVERALL SOCIETAL BENEFITS DISTINGUISHED FROM BENEFITS TO ELECTRICITY CUSTOMERS

Society as a whole benefits from transmission investments. As a result, we believe it is most relevant to examine the benefits associated with transmission investments from an economy-wide or societal perspective—as opposed to solely from a customer or generator perspective—when making public-policy or regulatory decisions. The Public Utility Commission of Texas (PUCT) requires that transmission projects be evaluated from a societal perspective, explicitly rejecting the use of a consumer impact or generator revenue reduction perspective for the evaluation of economic transmission projects in ERCOT.¹⁴⁹ Nevertheless, some other regions and regulators, utilities, and customer groups tend to focus on how electricity customers (*i.e.*, “ratepayers”) might benefit from the proposed transmission facilities.¹⁵⁰ Recognizing the differences in societal and customer perspectives, we thus briefly summarize key aspects of the two perspectives in this appendix.

This electricity-customer perspective is most relevant when one evaluates how much those who pay for the transmission projects would benefit from them. For instance, electricity customers are likely to benefit from production cost savings (through reduced electricity bills from cost-of-service regulated utilities), from improved reliability (which increases the value of the received service), from an increase in wholesale power market competition (even if that reduces generator profits), from reduced resource adequacy requirements or a reduction in the capacity cost of new generating resources (which reduces electricity bills), and from the avoidance or deferral of transmission or generation investments that would need to be built in the absence of the proposed transmission investment (which provides an offset to the larger transmission projects’ costs).

Increased system reliability, reduced emissions, or regional economic development will benefit society as a whole, which includes electricity customers. But these benefits may not directly reduce electricity customer bills. Because benefits to electricity customers can be either a subset of total economy-wide benefits (*e.g.*, because there are benefits that do not directly accrue to electricity customers) or exceed economy-wide benefits (*e.g.*, because generators may see

¹⁴⁹ See PUCT Order 2012. The PUCT Order refers to societal benefits as “levelized annual savings in system production costs resulting from the project,” consistent with the current scope of ERCOT’s economic benefit metrics (*id.*, pp. 15 and 18). However, the PUCT also concluded that “indirect benefits and cost” associated with a project, as discussed in ERCOT Nodal Protocols, Section 3.11.2(5), should be considered as well (*id.*, p. 32).

¹⁵⁰ Note that the academic literature generally discusses this subject matter by distinguishing between “societal benefits” (or total “welfare gains”), “consumer benefits” (or changes in “consumer surplus”), and “supplier benefits” (or changes in “supplier surplus”). We discuss these concepts in terms of overall economic (or economy-wide) benefits and electricity-customer benefits. See also Baldick, *et al.*, 2007, pp. 17-21.

reduced earnings or other electric customers may see increased rates), the benefit-to-cost balance from an economy-wide perspective may differ from that of electricity customers. For example, a transmission project may offer only limited system-wide production cost savings but offer significant electricity customer benefits by reducing market prices. Alternatively, a significant portion of system-wide production cost savings may be captured by merchant generators through increased earnings, resulting in electricity customer benefits that are less than the identified production cost savings.

The existence and extent of the divergence between customer and societal perspectives can depend on three factors: market structure, geographic scope of the study, and consideration of economy-wide benefits not reflected in electricity rates.

Market Structure. Generally speaking, the cost of power delivered to electricity customers can decrease if a transmission line allows for the dispatch of lower-cost generation or the purchase of wholesale power at lower prices. However, the extent to which electricity customers will benefit also depends on the structure of retail power markets. Under the traditional cost-of-service regulated model, electricity customers will directly benefit from: (1) reductions in the production costs of cost-of-service regulated generating plants; (2) lower-cost off-system purchases by the regulated utility; and (3) the achievement of higher off-system-sales prices for power from such regulated generating plants to offset the revenue requirement to be recovered from franchised ratepayers. In contrast, if electricity customers are served mostly through wholesale power purchases at market prices, such as in retail-access states, customers will benefit if a transmission project reduces the wholesale price of purchased power, irrespective of actual production cost savings. Reducing the cost of power to electricity customers is not automatically an economy-wide benefit because, when customers pay less for their power, a portion of those savings may be a transfer of economic gains from generators to those customers. This transfer of gains can yield a result in which the economy-wide benefit is less than the electricity-customer benefit. In other words, when customers pay less, generators may earn less, leaving the economy-wide benefit to be less than the direct benefits electricity customers may enjoy.

Geographic Scope of the Study. Transmission investments can affect a wide range of market participants in regions adjacent to where a project is located. When estimating the overall benefits of this type of transmission project, the impacts on consumers and generators in neighboring regions need to be considered as well. In some situations, the overall benefits of a transmission project may exceed the benefits realized in a particular region because additional benefits may accrue to electricity customers and generators in neighboring regions. It is also possible that the benefits to electricity customers in the region where the project is located exceed the overall economy-wide benefit if the transmission project increases electricity customers' costs in the neighboring regions. For example, a new transmission line that allows for local electricity customers to purchase power at lower prices from a neighboring market may

cause wholesale prices to increase in that neighboring market, possibly benefitting generators but increasing electricity customers' costs in the neighboring market.¹⁵¹

Economy-wide Benefits Not Reflected in Electricity Rates. The benefits of transmission investments may also extend beyond the direct benefits to electricity market participants. This is the case when some of the economy-wide benefits of transmission investments accrue to society more broadly—external to the scope of electricity costs, generator profits, or system reliability. For example, a reduction of greenhouse gas emissions due to a shift in generation resources towards more renewable energy resources resulting from a transmission upgrade can provide a societal benefit. Without a market that places an explicit monetary cost on the emissions, the societal benefit associated with reduced emissions would not materialize in reduced costs to electricity customers. Only if a price was placed on greenhouse gas emissions (as is the case for SO₂ and NO_x emissions) will the benefits associated with emissions reduction accrue to electricity customers through reduced costs. However, even though these emissions are not priced today, it is important to value on a probabilistic basis—including from a risk mitigation perspective—the likelihood that they will be priced in the future. Economy-wide benefits can also include the employment and economic development benefits of expanding the existing transmission infrastructure,¹⁵² including benefits from stimulating the local economy, producing additional tax revenues, supporting industrial growth, or allowing the development of renewable power projects that, in turn, provide many similar economic stimulus benefits. However, the jobs and economic stimulus associated with constructing and maintaining the transmission system would only provide incremental benefits to a region if alternative investment activities could not offer similar benefits.¹⁵³ Thus, while it is useful to estimate the potential employment and economic stimulus benefits associated with certain transmission investments, they cannot simply be added to other project benefits for the purpose of benefit-cost analyses.

Overall, we recommend using a societal or economy-wide perspective (with a sufficiently wide geographic scope) when evaluating the benefits and costs of transmission projects. However, due to regulatory requirements or for cost allocation purposes, it may also be necessary to conduct the analysis from an electricity customer perspective. In either case, it is important to deliberately specify how market structure and the geographic scope of the study will affect the

¹⁵¹ For a simplified illustration and discussion of how economy-wide benefits compare to electricity customer and generator benefits in two regions interconnected by a transmission upgrade, see also Hogan, 2011.

¹⁵² However, it is important to ensure that the partial macroeconomic impacts associated with changes in spending in the power sector is not directly added to the spending effects already accounted for in the other benefit categories.

¹⁵³ For example, if workers are fully employed in an economy, building more transmission may not offer additional employment benefits to the region, and job creation alone does not necessarily or automatically ensure that certain investments provide a productive use of the associated investment capital. Further, the employment-related benefits from constructing transmission facilities would need to be weighed against the economic implications of potential increases in electricity rates.

investments' benefits and costs. Evaluating impacts from an electricity customer perspective should also consider benefits (such as increased reliability) that are not reflected in electricity rates.

APPENDIX D - STAKEHOLDER PARTICIPATION LIST

Stakeholders interviewed during the initial study effort:

Organization:	AEP
Date:	April 26, 2013
Attendees:	Jennifer L. Bevill and others
Organization:	Austin Energy
Date:	April 30, 2013
Attendees:	Biju Matthew, Reza Ebrahimiaan
Organization:	Edison Mission
Date:	April 22, 2013
Attendees:	Marguerite Wagner
Organization:	Lone Star Transmission
Date:	March 25, 2013
Attendees:	Matthew Gomes and others
Organization:	Lower Colorado River Authority (LCRA)
Date:	April 17, 2013
Written comments:	Sergio Garza
Organization:	Luminant
Date:	March 26, 2013
Attendees:	Shannon Caraway, Vicki Oswalt, Amanda Frazier, Ed Svihla
Organization:	Oncor
Date:	March 26, 2013
Attendees:	Mike Juricek, Liz Jones, April Pinkston
Organization:	Potomac Economics
Date:	April 3, 2013
Attendees:	Dan Jones
Organization:	Save Our Scenic Hill Country Environment (SOSCHE)
Date:	March 25, 2013
Attendees:	Robert Weatherford, Tim Lehmberg, Roger Studer
Organization:	Stratus Energy
Date:	March 25, 2013
Attendees:	John Moore
Organization:	Texas Landowners Representatives , including Tri-Community Alliance, F-to-Z Coalition, Energy Edge Consulting
Date:	May 2, 2013
Attendees:	Brad Baliff and representatives of each organization
Organization:	Texas Industrial Energy Customers
Date:	March 25, 2013
Attendees:	Katie Coleman, Charles Trissey

Stakeholders who submitted comments on draft recommendations:

Organization:	Luminant
Date:	June 28, 2013
Name:	Amanda J. Frazier
Organization:	Oncor
Date:	June 28, 2013
Name:	April C. Pinkston
Organization:	South Texas Electric Cooperative
Date:	June 25, 2013
Name:	John Moore
Organization:	Texas Industrial Energy Customers
Date:	June 24, 2013
Name:	Katie Coleman
Organization:	Lone Star Transmission
Date:	June 24, 2013
Name:	Randa Stephenson
Organization:	Electric Power Engineers, Inc.
Date:	June 28, 2013
Name:	Hala N. Ballouz
Organization:	Lower Colorado River Authority (LCRA)
Date:	June 21, 2013
Name:	Segio Garza
Organization:	AEP
Date:	June 18, 2013
Name:	Jennifer L. Bevill
Organization:	Public Utility Commission of Texas
Date:	June 18, 2013
Name:	Mike Lee
Organization:	ERCOT
Date:	June 17, 2013
Name:	John Adams
Organization:	Save Our Scenic Hill Country Environment (SOSCHE)
Date:	June 6, 2013
Name:	Robert Weatherford

APPENDIX E – JUNE 3, 2013 RPG PRESENTATION: “DRAFT RECOMMENDATIONS FOR ENHANCING ERCOT’S LONG-TERM TRANSMISSION PLANNING PROCESS”

The Brattle Group

Recommendations for Enhancing ERCOT’s Long-Term Transmission Planning Process

Presented to:
ERCOT Regional Planning Group

Presented by:
**Johannes Pfeifenberger
Judy Chang**

June 3, 2013

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Antitrust/Competition Commercial Damages Environmental Litigation and Regulation Forensic Economics Intellectual Property International Arbitration
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Electric Power Financial Institutions Natural Gas Petroleum Pharmaceuticals, Medical Devices, and Biotechnology Telecommunications and Media Transportation

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- Session 5: Societal Benefits Metrics**
- Appendix: Details on Societal Benefit Metrics**

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Background on Long-Term Planning Process

DOE Grant is used to enhance ERCOT long-term planning:

- ◆ Augment and enhance the existing long-term planning efforts for the ERCOT region
- ◆ Increase the technical knowledge and capabilities of ERCOT staff
- ◆ Expand the long-term planning horizon to 20-years
- ◆ Support expansion of the existing ERCOT planning stakeholder process

Specifically, the intent of this effort is to:

- ◆ Provide relevant and timely information on the long-term system needs to inform nearer-term planning and policy decisions
- ◆ Expand ERCOT long-term planning capabilities by developing new tools and processes, including:
 - Extending the planning horizon
 - Incorporating the operational reliability and detailed analysis of the economic viability of emerging technologies
- ◆ Facilitate enhanced stakeholder involvement and input into the long-term planning process that seeks for stakeholder consensus.

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Resulting Long-Term Study (LTS)

ERCOT's effort of enhancing its long-term planning process involves:

- ◆ Assessment of transmission needs under various future scenarios
 - Scenarios (over 20-year horizon) were developed through a stakeholder-based "Scenario Development Working Group"
 - Supplement existing 10-year long-term system assessment (LTSA)
- ◆ Analyses of proposed economic transmission projects
 - Modeling impact of on production costs and system reliability
 - Compare benefits to costs of economic transmission projects
- ◆ "Indicative" results about beneficial transmission projects

The long-term-planning effort is intended to:

- ◆ Supplement RTP process to help improve understanding of economic value, identify additional economic projects, increase robustness and benefits of transmission options in long-term
- ◆ Indicate system needs that require longer implementation time frame than 5-6 years (if any)

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Objectives of Brattle Engagement

Review long-term planning process and develop recommendations to improve business case for transmission from societal perspective:

- ◆ Provide careful review and suggest improvements to the long-term transmission planning process
- ◆ Provide ERCOT options for expanding its planning processes to include more comprehensive assessments of transmission benefits and costs
 - Develop and demonstrate metrics and methodologies for valuing additional (non-conventional) transmission-related societal benefits
- ◆ Assist ERCOT in improving its modeling of the impact of transmission projects
 - Identify the strengths and weaknesses of existing models and tools
 - Suggest improvements in modeling applications and procedures
- ◆ Conduct workshops for ERCOT staff, to educate stakeholder, and present results and recommendations

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Our Approach to this Effort

1. Reviewed documentation on ERCOT RTP (near-term) and long-term (LTSA and LTS) planning processes
2. Interviewed stakeholders and ERCOT staff to:
 - Better understand overall study approach
 - Collect stakeholders' views on existing process and potential improvements
 - Understand modeling practices and flow of data and information among ERCOT internal teams
3. Reviewed long-term planning process to evaluate its effectiveness
4. Reviewed and evaluated ERCOT's current modeling approach
5. Proposing additional transmission benefits metrics that can be incorporated in evaluating the merits of potential projects
6. Conducting discussions on how to improve specific benefit-cost evaluation approaches (based on industry's best practices)
7. Brattle report due in early July (appendix to ERCOT's DOE report)

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Areas of Long-Term Planning Addressed		
	Assess and Improve the Process for the Existing Planning Scope	Broaden the Scope to More Effectively Identify Projects with Net Benefits
1. Study Plan (objectives and high-level concepts)	<ul style="list-style-type: none"> - Identify limitations of scope of benefits quantified and project evaluation criteria 	<ul style="list-style-type: none"> - Add benefit categories and metrics - Describe how study scope could be improved - Suggest enhancements to project evaluation criteria
2. Process Steps	<ul style="list-style-type: none"> - Identify opportunities for improving and streamlining the process - Will be informed by an assessment of effort and value, and comparison to processes we've done/seen - Clarify process/stakeholder input for identifying promising projects and their likely benefit categories 	<ul style="list-style-type: none"> - Identify aspects that can be readily added to existing modeling system - How to evaluate benefits that can not be captured in existing modeling system - For additions that may be a more major effort: <ul style="list-style-type: none"> - Develop potential process modifications - Identify ways to streamline (e.g., apply selectively or to a portfolio; develop generic benefit multipliers)
3. Modeling Tools, Execution, and Quality Control Practices	<ul style="list-style-type: none"> - Identify specific improvement opportunities for: <ul style="list-style-type: none"> - model calibration - quality control (diagnostics and review) - data and case management - automation of repeated processes - documentation of modeling steps - staff training 	<ul style="list-style-type: none"> - What are best practices and training needs for successfully executing new steps/tools?
4. What to do with the Results		<ul style="list-style-type: none"> - Identify ways to integrate LT planning better with actionable near-term planning (e.g., by merging models and including LT NPV in near-term study)

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Summary of Stakeholder Comments

We interviewed a wide range of stakeholders:

- ◆ Transmission service providers, land owners, generators, municipal utilities, consultants, and the Market Monitor

Main themes of feedback targeted on:

- ◆ Appreciative of ERCOT's effort; significant value in conducting long-term planning; hopeful that this effort will enhance planning over time
- ◆ Questions about scenarios
 - Not fully clear how they came about
 - Future uncertainties covered by the scenarios too wide or too narrow
- ◆ Need more clarity around how the results of long-term planning efforts will being used
- ◆ Unclear about extent to which stakeholder input can be provided or can make a difference

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Stakeholder Comments: Agreed-Upon Next Steps

Generally agreed-upon areas for further improvement:

- ◆ Next phase needs to sharpen the goal definition of Long-Term Planning and needs to establish how results generated through Long-Term Planning will influence "actionable" Regional Transmission Plans
- ◆ This first iteration of the effort has been a helpful learning experience; For actual planning going forward, results are only trusted if assumptions and scenarios are considered to be reasonable:
 - Scenarios/assumptions need to be refined; require more widespread buy-in
 - Need to increase level of stakeholder engagement and comfort
- ◆ ERCOT expertise and modeling capability valuable; should be supplemented with more stakeholder input and expertise:
 - Local system knowledge should considered more actively when developing project ideas
 - Bottom-up load forecasting can add value to ERCOT long-term projections

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Stakeholder Comments: Differences of Opinions

Areas where stakeholders have difference of opinions:

- ♦ Desired level of stakeholder involvement
 - Some believe that ERCOT has done a good job facilitating stakeholder input and developing scenarios
 - Others felt excluded either by an inability to participate, difficulties to comprehend, or providing input that they thought was not considered
 - Some intentionally did not participate (more) actively because they felt Long-Term Planning results are not useful or are not going to be used to plan actual transmission projects
- ♦ Types of transmission benefits considered
 - Some support ERCOT's effort to capture more economic benefits; they believe many benefits have not yet been considered but should be
 - Others believe that adding benefits will increase unnecessary transmission build-out and are concerned about adding benefits without considering additional costs

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Stakeholder Comments: Differences of Opinions

Areas with difference of opinions (cont'd):

- ♦ Range of future scenarios
 - Some believe the range of scenarios are too narrow (too similar), recommending that a wider range of futures that would significantly challenge the system be considered
 - Unclear if assumptions are internally consistent within the scenarios (e.g., renewable energy costs in some of the scenarios)
- ♦ Disagreement over the value of long-term planning
 - Some question the value of scenarios and uncertain 10-20 year outlook when transmission can be built quickly in Texas to address challenges when they arise
 - Others are very positive and appreciative about ERCOT taking this step and developing a long-term, scenario-based planning process

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Stakeholder Comments: Our Recommendations

We believe ERCOT has an opportunity to increase stakeholder participation:

- ◆ Refine the long-term planning process to ensure that “results matter” and stakeholders understand how
 - Explain how long-term-planning results will be used in RTP process
- ◆ Reiterate invitation to all potentially interested parties to participate
- ◆ Conduct workshop on scenario development that involves
 - Experts outside of ERCOT and power industry to share views of the future
 - Stakeholder representatives from each sector
 - Document collective results from scenarios developed
- ◆ Ensure that scenarios are well documented, shared with all stakeholders, and understood
- ◆ Clarify types of transmission benefits and costs considered
 - Conduct special workshop to explain the details of all benefits metrics
 - Explain in detail how benefits will be compared to costs

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Modeling Practices: Assessment

What's working well:

- ◆ Modeling process is well designed and documented
- ◆ Team Members have high degree of expertise
- ◆ Modeling techniques are best-in-class with respect to siting generic generation and making reliability upgrades and transmission constraints internally consistent within each case
- ◆ Documentation of process steps and results

Areas for improvement:

- ◆ Organizational and modeling team structure
- ◆ Model calibration, validation of results
- ◆ Simulation of scenarios

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Modeling Practices: Recommendations

Integrate organizational and modeling team structure

- ◆ Use a single economic model for mid-term and long-term
- ◆ Consolidate teams (this is already in process)
- ◆ Benefits: this will improve quality/consistency and workflow efficiency; it will also enable the integrated, multi-year planning process we recommend (see next section)

Calibrate models and validate results more systematically

- ◆ Backcasting (e.g., price levels and variance, scarcity conditions)
- ◆ Develop standardized diagnostics tools

Enhance scenario and uncertainty modeling

- ◆ Improve simulations to capture actual levels of congestion and production costs more accurately across all scenarios
- ◆ Develop simulation of uncertainties within scenarios (e.g., weather or outage-related stress conditions)

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Current Planning Process: Areas for Improvement

We identified room for improvement in the current long-term transmission planning process:

- ♦ Current implementation of economic project process will miss beneficial projects by considering only the first year of a project:
 - First year production cost savings generally lower than their levelized value because benefits tend to grow over time
 - Note: first-year project costs (estimated at 1/6 of construction costs) are higher than their levelized value because project costs decline over time as the assets are depreciated
- ♦ Current economic project process and tools understate production cost savings and do not capture a range of other potential benefits and costs
- ♦ Disconnect in near-term/long-term planning processes can result in missed opportunities to identify beneficial economic projects that avoid or defer reliability projects
 - Once a reliability project is built, an economic project generally will not be as valuable than otherwise due to missed benefits from earlier years and the missed opportunity to avoid the reliability project costs

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Economic Planning Process: Recommendations

Recommended improvements to the long-term economic transmission planning process for further consideration:

1. Stitch together the RTP and Long-Term economic evaluation scope, so that Long-Term Planning results can be used in the RTP
2. Use Long-Term Planning results in evaluating economic projects in RTP (and the possibility of avoiding/deferring reliability projects)
 - Allows analysis of whether an economic project identified in Long-Term-Planning effort should be accelerated for consideration in RTP:
 - For example, advance a possible economic project from year 10 to avoid reliability upgrade in year 5 (and likely additional reliability upgrades in years 10 and 15)
 - Use Long-Term Planning to assess value of economic project alternatives to reliability upgrades identified within RTP process
 - Projects would still be approved through RTP for in-service dates within RTP timeframe, but their value would be informed by long-term assessment
3. Expand benefits and costs considered and develop metrics to quantify their monetary value

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Economic Planning Process: Recommendations

4. Implement NPV-based/levelized benefit-cost comparison
 - Levelized value of societal benefits tends to far exceed their first-year value
 - Note: first-year transmission revenue requirement (TRR) (approximately equal to 1/6 of project construction costs) is about 30% higher than the levelized value of TRRs over the project life, creating a B-C threshold of 1.3
5. Improve the use of scenarios and sensitivities in the planning process
 - Use long-term scenarios (e.g., of alternative outlooks for fuel prices, load growth, generation mix, locations, etc.) to test the robustness of economic projects, including those considered in the RTP
 - Consider uncertainties (e.g., weather, contingencies, fuel costs) through simulation of sensitivities within each scenario (i.e., for same normalized load and generation mix) to capture full expected value of benefits
6. Enhance economic project and benefits/costs identification process:
 - Formalize process for market participants to propose economic projects and specify all benefits and costs (see "checklist" of possible benefits)
 - Obtain broad stakeholder input on the proposed transmission projects and their identified societal benefits and costs to help prioritize

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Need for Linking Near- and Long-Term Planning

Differences in analytical approaches used to identify reliability and economic transmission projects require integration of near- and long-term planning processes.

- ◆ Reliability need is determined for a single point in time (e.g., 2017)
- ◆ The societal economic value of a transmission project for that *same point in time* (e.g., 2017) is dependent on the present value of its annual costs and benefits, looking forward over the entire life of the asset (e.g., 2017-57)
- ◆ Present values of actual annual costs and benefits can easily be expressed as “levelized” annual values that yield exactly the same present value.

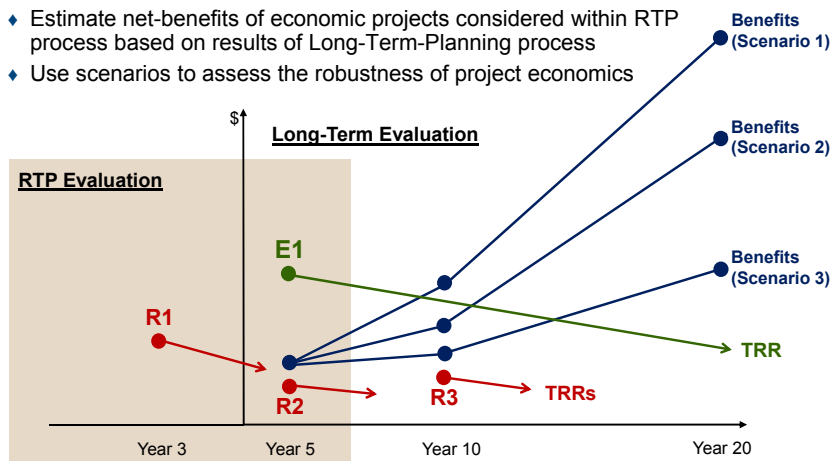
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Use Long-Term Planning to Supplement RTP

We recommend that ERCOT use “look ahead” from Long-Term Planning to increase the robustness of RTP decisions:

- ◆ Estimate net-benefits of economic projects considered within RTP process based on results of Long-Term-Planning process
- ◆ Use scenarios to assess the robustness of project economics



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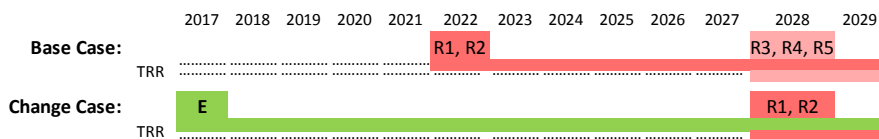
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Example: Long-Term Benefits of Economic Project

Realistic example of an Economic Project built in 2017

- ◆ Defers: \$90 million reliability projects (R1, R2) from 2022 to 2028
- ◆ Avoids: \$321 million reliability projects (R1, R2, R3) in 2028



Benefits estimation involves the following steps:

- ◆ Estimate costs and benefits in Base Case (for selected years), represented by the combination of R1,2 and R3, R4, R5
- ◆ Estimate costs and benefits the Economic Project for same years
- ◆ Difference between the two streams of costs and benefits = *Incremental benefits associated with the Economic Project*

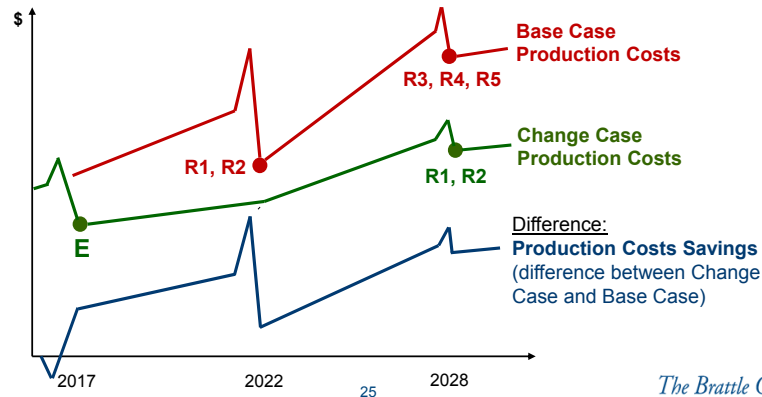
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Example: Production Cost Savings (Concept)

Economic project (“E” in Change Case) offers benefits relative to reliability solution (“R1, R2” and “R3, R4, R5” in Base Case):

- ♦ Production cost savings (as illustrated below)
- ♦ Deferred (R1, R2) and avoided (R3, R4, R5) reliability project costs



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Example: Production Cost Savings (Results)

Results from ERCOT production cost simulations:

- ♦ Production costs savings estimated for 2017, 2022, and 2028 as difference between Base Case and Change Case, showing:

	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028
Base Case	\$15,233	\$15,881	\$16,528	\$17,176	\$17,823	\$18,468	\$19,084	\$19,700	\$20,316	\$20,932	\$21,549	\$22,128
Change Case	\$15,228	\$15,870	\$16,511	\$17,153	\$17,794	\$18,436	\$19,037	\$19,637	\$20,238	\$20,839	\$21,440	\$22,038
Savings:	\$5	\$11	\$17	\$23	\$29	\$32	\$48	\$63	\$78	\$93	\$109	\$90

- \$5 million in 2017 \$32 million in 2022 \$90 million in 2028
- ♦ Interpolated production cost savings between 2017, 2022, and 2028
 - Used 2022 and 2028 cases without reliability upgrades to estimate 2021 and 2027 savings for interpolation purposes
 - Held 2028 savings constant in real terms (i.e., grown with inflation)
- ♦ Estimated benefit of deferring/avoiding reliability projects
 - Difference in reliability-project TRRs for Base Case and Change Case

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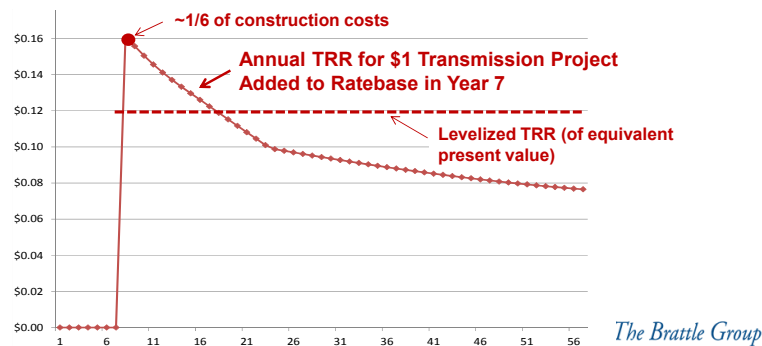
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Transmission Revenue Requirements (TRR)

Under “cost-of-service” regulation, the annual cost of transmission is calculated as an asset’s TRR:

$$\text{TRR} = \text{Depreciation} + \text{Return on Ratebase} + \text{Taxes} + \text{O\&M Costs}$$

- ◆ TRRs decline as the project’s Ratebase is depreciated over time
- ◆ Accelerated tax depreciation makes TRRs decline faster over initial 15 years

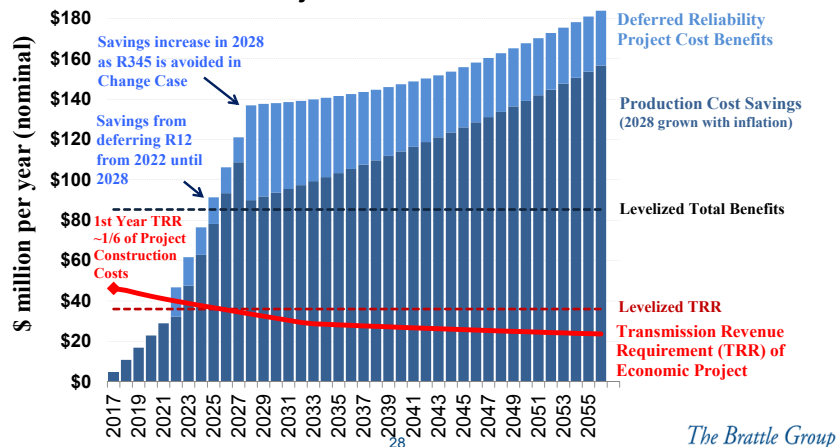


Example: 40-year NPV of Economic Project

2017 PV of Economic Project TRRs = \$465 million

2017 PV of Benefits = \$866 million + \$241 million = \$1,107 million

2017 NPV of Economic Project = +\$643 million



Example: Take Aways

Example shows that project would be rejected based on current benefit-cost approach:

- ◆ First-year production cost savings (\$5 million) compares poorly to 1/6 of construction costs (\$49 million)

Long-term perspective shows that the 2017 value of production cost savings and avoided reliability project costs far exceed the economic project's costs:

- ◆ \$1.1 billion PV of project benefits vs. \$465 million PV of project TRRs
- ◆ \$85 million of levelized annual benefits vs. \$36 million in levelized TRRs and \$49 million when measured against 1/6 of construction costs
- ◆ Other benefits (or costs) still need to be considered

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Example: Take Aways

Results also show that, in this case, the value of the economic project might be increased by delaying it until the R1+R2 reliability upgrade would be needed otherwise (e.g., in 2022):

- ◆ Economic project is not needed for reliability in 2017
- ◆ Production-cost savings suggests that the economic project is not providing net benefits until 2022 or after (but other benefits may change that result)

Question remains:

- ◆ Whether this (or other) economic project could also cost-effectively defer/avoid other RTP-identified reliability upgrades
- ◆ What other tangible societal benefits are provided by the economic project and how can these benefits (or costs) be quantified or otherwise considered (see next Session)

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Societal Benefit Metrics: Assessment

Societal benefits already considered in ERCOT's assessment of economic projects:

- ◆ Production cost saving
- ◆ Benefits of deferring/avoiding reliability upgrades

This scope does not capture the full societal benefits and costs of new transmission

The current scope is narrower than evolving industry practice, which is considering a broader range of transmission-related benefits

- ◆ Examples from other regions (see next two slides)
- ◆ Requires careful definition of all societal costs and benefits for cases with and without the contemplated transmission projects
- ◆ Some of these benefits can be negative (i.e., reflect costs)

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Metrics Used in Other RTOs

SPP ITP analysis:

Quantified

1. production cost savings
2. reduced transmission losses
3. wind revenue impacts
4. natural gas market benefits
5. reliability benefits
6. economic stimulus benefits of transmission and wind generation construction

Not quantified

7. enabling future markets
8. storm hardening
9. improving operating practices/maintenance schedules
10. lowering reliability margins
11. improving dynamic performance and grid stability during extreme events
12. societal economic benefits

(SPP Priority Projects Phase II Final Report, SPP Board Approved April 27, 2010; see also SPP Metrics Task Force, *Benefits for the 2013 Regional Cost Allocation Review*, July, 5 2012.)

MISO MVP analysis:

Quantified

1. production cost savings
2. reduced operating reserves
3. reduced planning reserves
4. reduced transmission losses
5. reduced renewable generation investment costs
6. reduced future transmission investment costs

Not quantified

7. enhanced generation policy flexibility
8. increased system robustness
9. decreased natural gas price risk
10. decreased CO₂ emissions output
11. decreased wind generation volatility
12. increased local investment and job creation

(Proposed Multi Value Project Portfolio, Technical Study Task Force and Business Case Workshop August 22, 2011)

CAISO TEAM analysis

(PVD2 example)

Quantified

1. production cost savings and reduced energy prices from both a societal and customer perspective
2. mitigation of market power
3. insurance value for high-impact low-probability events
4. capacity benefits due to reduced generation investment costs
5. operational benefits (RMR)
6. reduced transmission losses
7. emissions benefit

Not quantified

8. facilitation of the retirement of aging power plants
9. encouraging fuel diversity
10. improved reserve sharing
11. increased voltage support

(CPUC Decision 07-01-040, January 25, 2007 (Opinion Granting a Certificate of Public Convenience and Necessity))

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2012 Effort by SPP's Metrics Task Force

Benefits	Metric	Standard SPP Metric	Recommended New Metric
Adjusted Production Cost Benefits	Adjusted Production Costs	√	
	Energy losses benefits		√
	Mitigation of transmission outage costs		√
Capacity for Losses	Reduced capacity costs	√	
Improvements in Reliability	Avoided or delayed reliability projects	√	
	Capital savings associated with reduced capacity margin		√
	Reduced loss of load probability		√
	Reduced cost of extreme events		√
	Assumed benefits of mandated reliability projects		√
Reduction of Emission Rates and Values	Reduction of emission rates and values	√	
Reduced Operating Reserves Benefits	Lower ancillary services needs and costs	√	
Improvements to Import/Export Limits	Increased wheeling through and out revenues		√
Public Policy Benefits	Meeting policy goals		√

Benefit Metrics Recommendations for ERCOT

We documented industry practice and outlined a broader set of benefits we recommend that ERCOT consider

Organized the additional benefits/metrics into four categories:

- ◆ Additional benefits and metrics that should be evaluated routinely
- ◆ Those that should be included by developing typical multipliers
- ◆ Those for which additional data and tools need to be developed
- ◆ Those that should be considered only qualitatively for now

Recommend improved societal benefit/cost identification process:

- ◆ Allow market participants propose economic projects, including their likely benefits and costs (based on full “checklist” of possible benefits)
- ◆ Obtain broad stakeholder input on the proposed transmission projects and their identified benefits/costs to help prioritize

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Recommendation: Checklist of Economic Benefits

<u>Benefit Category</u>	<u>Transmission Benefit (see Appendix for descriptions and detail)</u>
Standard Production Cost Savings	Production cost savings as currently estimated by ERCOT staff
1. Additional Production Cost Savings	a. Impact of generation outages and A/S unit designations
	b. Reduced transmission energy losses
	c. Reduced congestion due to transmission outages
	d. Mitigation of extreme events and system contingencies
	e. Mitigation of weather and load uncertainty
	f. Reduced cost due to imperfect foresight of real-time system conditions
	g. Reduced cost of cycling power plants
	h. Reduced amounts and costs of operating reserves and other ancillary services
	i. Mitigation of reliability-must-run (RMR) conditions
2. Reliability and Resource Adequacy Benefits	a. Avoided/deferred reliability projects (already considered in LTSA)
	b. Reduced loss of load probability or c. reduced planning reserve margin
3. Generation Capacity Cost Savings	a. Capacity cost benefits from reduced peak energy losses
	b. Deferred generation capacity investments
	d. Access to lower-cost generation resources
4. Market Benefits	a. Increased competition
	b. Increased market liquidity
5. Environmental Benefits	a. Reduced emissions of air pollutants
	b. Improved utilization of transmission corridors
6. Public Policy Benefits	Reduced cost of meeting public policy goals
7. Employment and Economic Stimulus Benefits	Increased employment and economic activity; Increased tax revenues
8. Other Project-Specific Benefits	Examples: storm hardening, increased fuel diversity, reducing the cost of future transmission needs, HVDC operational benefits

Recommendations: 1. Production Cost Savings					
Transmission Benefit	Add as Standard Metric Now	Develop Typical Multiplier	Develop Data and Tool for Future use	Consider Qualitatively for Now	Notes
1a. Reduced impact of generation outages and A/S unit designations	√				Consider both planned and forced outages in all simulations
1b. Reduced cost of transmission energy losses	√				Estimate based on MLC or full marginal loss simulations
1c. Reduced congestion due to transmission outages		√			Study impact of historical transmission outages
1d. Mitigation of extreme events and system contingencies			√		Develop examples for extreme contingencies and study impacts
1e. Mitigation of weather and load uncertainty		√			Study benefits for 10/90, 50/50, and 90/10 loads
1f. Reduced congestion due to imperfect foresight of real-time conditions				√	Utilize KERMIT zonal simulations as need arises
1g. Reduced cost of cycling power plants	√				Startup costs, increased maintenance costs
1h. Reduced amounts and costs of ancillary services				√	Study conditions under which transmission can provide this benefit (or add to costs)
1i. Mitigation RMR conditions			√		Estimate as RMR need is identified
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Recommendations: 2+3. Resource Adequacy and Generation Capacity Cost Savings					
Transmission Benefit	Add as Standard Metric Now	Develop Typical Multiplier	Develop Data and Tool for Future use	Consider Qualitatively for Now	Notes
2a. Avoided or deferred reliability projects	Improve existing approach				Add analysis of present value of multiple avoided or deferred future upgrades
2b. Reduced loss of load probability			√		Utilize results of zonal reliability analyses or use PROMOD reliability simulation option
Or: 2c. Reduced planning reserve margin			√		Same as 2b but different realization of savings.
3a. Capacity cost benefits from reduced peak energy losses	√				Estimated based on change in on-peak losses and CONE
3b. Deferred generation capacity investments			√		Further explore potential for ERCOT
3c. Access to lower-cost generation			√		Study locational generation cost differences
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Recommendations: 4-7. Market, Environmental, Public Policy, and Economic Stimulus Benefits					
Transmission Benefit	Add as Standard Metric Now	Develop Typical Multiplier	Develop Data and Tool for Future use	Consider Qualitatively for Now	Notes
4a. Increased competition				√	Study bid mark-ups in load pockets as function of RSI and import capability
4b. Increased market liquidity				√	Study impact of liquidity at trading hubs on transaction costs (bid-ask spreads; hedging costs)
5a. Reduced emissions of air pollutants	√			√	Include emission prices in simulations; consider non-monetized emissions and risk mitigation in long-term scenarios
5b. Improved utilization of transmission corridors			√		Develop approach as project with unique transmission corridor benefit s/costs is encountered
6. Reduced cost of meeting public policy goals				√	Develop quantification approach as public policy requirements or goals are specified
7. Increased employment, economic activity, and tax revenues				√	Provide estimate of employment and economic stimulus benefit per \$ million of transmission investment in Texas
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Recommendations: 8. Other Transmission Benefits					
Transmission Benefit	Add as Standard Metric Now	Develop Typical Multiplier	Develop Data and Tool for Future use	Consider Qualitatively for Now	Notes
8a. Storm hardening				√	Study impact on customer outages and restoration times; compare to alternative costs of achieving same hardening
8b. Increased load serving capability				√	Develop metric as projects with promising increases in future load serving capability are planned
8c. Synergies with future transmission projects			√		Develop framework and most likely applications (e.g., projects that create low-cost future option)
8d. Increased fuel diversity and resource planning flexibility			√		Study generation expansion scenarios to understand value of transmission to mitigate costs of future fuel-mix and locational shifts
8e. Increased wheeling revenues				√	Develop metric as transmission projects that increase imports/exports are considered
8f. Increased transmission rights and congestion-hedging value				√	Develop if deficiencies in congestion hedging options are identified
8g. Operational benefits of HVDC transmission				√	Document and consider operational benefits of HVDC technology as projects are planned
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1. Additional Production Cost Savings			
Transmission Benefit	Benefit Description	Approach to Estimating Benefit	Examples
1a. Reduced impact of generation outages and A/S designations	Consideration of generation outages (and A/S unit designations) will increase impact	Consider both planning and (at least one draw of) forced outages in market simulations. Set aside resources to provide A/S in non-optimized markets.	Outages considered in most RTO's
1b. Reduced transmission energy losses	Reduced energy losses incurred in transmittal of power from generation to loads reduces production costs	Either (1) simulate losses in production cost models; (2) estimate changes in losses with power flow models for range of hours; or (3) estimate how cost of supplying losses will likely change with marginal loss charges	CAISO (PVD2) ATC Paddock-Rockdale SPP (RCAR)
1c. Reduced congestion due to transmission outages	Reduced production costs during transmission outages that significantly increase transmission congestion	Introduce data set of normalized outage schedule (not including extreme events) into simulations or reduce limits of constraints that make constraints bind more frequently	SPP (RCAR) RITELine
1d. Mitigation of extreme events and system contingencies	Reduced production costs during extreme events, such as unusual weather conditions, fuel shortages, or multiple outages.	Calculate the probability-weighted production cost benefits through production cost simulation for a set of extreme historical market conditions	CAISO (PVD2) ATC Paddock-Rockdale
1e. Mitigation of weather and load uncertainty	Reduced production costs during higher than normal load conditions or significant shifts in regional weather patterns	Use SPP suggested modeling of 90/10 and 10/90 load conditions as well as scenarios reflecting common regional weather patterns	SPP (RCAR)
1f. Reduced costs due to imperfect foresight of real-time conditions	Reduced production costs during deviations from forecasted load conditions, intermittent resource generation, or plant outages	Simulate one set of anticipated load and generation conditions for commitment (e.g., day ahead) and another set of load and generation conditions during real-time based on historical data	N/A
1g. Reduced cost of cycling power plants	Reduced production costs due to reduction in costly cycling of power plants	Further develop and test production cost simulation to fully quantify this potential benefit ; include long-term impact on maintenance costs	WECC study
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1. Additional Production Cost Savings (cont'd)

Transmission Benefit	Benefit Description	Approach to Estimating Benefit	Examples
1h. Reduced amounts and costs of ancillary services	Reduced production costs for required level of operating reserves	Analyze quantity and type of ancillary services needed with and without the contemplated transmission investments	NTTG WestConnect MISO MVP
1i. Mitigation RMR conditions	Reduced dispatch of high-cost RMR generators	Changes in RMR determined with external model used as input to production cost simulations	ITC-Entergy CAISO (PVD2)

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2+3. Resource Adequacy and Generation Capacity Cost Savings

Transmission Benefit	Benefit Description	Approach to Estimating Benefit	Examples
2a. Avoided or deferred reliability projects	Reduced costs on avoided or delayed transmission lines otherwise required to meet future reliability standards	Calculate present value of difference in revenue requirements of future reliability projects with and without transmission line, including trajectory of when lines are likely to be installed	ERCOT All RTOs and non-RTOs ITC-Entergy analysis MISO MVP
2b. Reduced loss of load probability Or:	Reduced frequency of loss of load events (if planning reserve margin is not changed despite lower LOLEs)	Calculate value of reliability benefit by multiplying the estimated reduction in Expected Unserved Energy (MWh) by the customer-weighted average Value of Lost Load (\$/MWh)	SPP (RCAR)
2c. Reduced planning reserve margin	Reduced investment in capacity to meet resource adequacy requirements (if planning reserve margin is reduced)	Calculate present value of difference in estimated net cost of new entry (Net CONE) with and without transmission line due to reduced resource adequacy requirements	MISO MVP SPP (RCAR)
3a. Capacity cost benefits from reduced peak energy losses	Reduced energy losses during peak load reduces generation capacity investment needs	Calculate present value of difference in estimated net cost of new entry (Net CONE) with and without transmission line due to capacity savings from reduced energy losses	ATC Paddock-Rockdale MISO MVP SPP ITC-Entergy
3b. Deferred generation capacity investments	Reduced costs of generation capacity investments through expanded import capability into resource-constrained areas	Calculate present value of capacity cost savings due to deferred generation investments based on Net CONE or capacity market price data	ITC-Entergy
3c. Access to lower-cost generation	Reduced total cost of generation due to ability to locate units in a more economically efficient location	Calculate reduction in total costs from changes in the location of generation attributed to access provided by new transmission line	CAISO (PVD2) MISO ATC Paddock-Rockdale

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4+5+6+7. Market, Environmental, Public Policy, and Economic Stimulus Benefits

	Transmission Benefit	Benefit Description	Approach to Estimating Benefit	Examples
4. Market Benefits	4a. Increased competition	Reduced bid prices in wholesale market due to increased competition amongst generators	Calculate reduction in bids due to increased competition by modeling supplier bid behavior based on market structure and prevalence of "pivotal suppliers"	ATC Paddock-Rockdale CAISO (PVD2, Path 26 Upgrade)
	4b. Increased market liquidity	Reduced transaction costs and price uncertainty	Estimate differences in bid-ask spreads for more and less liquid markets; estimate impact on transmission upgrades on market liquidity	SCE (PVD2)
5. Environmental Benefits	5a. Reduced emissions of air pollutants	Reduced output from generation resources with high emissions	Additional calculations to determine net benefit emission reductions not already reflected in production cost savings	NYISO CAISO
	5b. Improved utilization of transmission corridors	Preserve option to build transmission upgrade on an existing corridor or reduce the cost of foreclosing that option	Compare cost and benefits of upsizing transmission project (e.g., single circuit line on double-circuit towers; 765kV line operated at 345kV)	N/A
6. Public Policy Benefits	Reduced cost of meeting public policy goals	Reduced cost of meeting policy goals, such as RPS	Calculate avoided cost of most cost effective solution to provide compliance to policy goal	ERCOT CREZ ISO-NE, CAISO MISO MVP SPP (RCAR)
7. Employment and Economic Stimulus Benefits	Increased employment, economic activity, and tax revenues	Increased full-time equivalent (FTE) years of employment and economic activity related to new transmission line	A separate analysis required for quantification of employment and economic activity benefits that are not additive to other benefits.	SPP MISO MVP

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8. Other Project-Specific Benefits

Transmission Benefit	Benefit Description	Approach to Estimating Benefit	Examples
8a. Storm hardening	Increased storm resilience of existing grid transmission system	Estimate VOLL of reduced storm-related outages. Or estimate acceptable avoided costs of upgrades to existing system	ITC-Entergy
8b. Increased load serving capability	Increase future load-serving capability ahead of specific load interconnection requests	Avoided cost of incremental future upgrades; economic development benefit of infrastructure that can	
8c. Synergies with future transmission projects	Provide option for a lower-cost upgrade of other transmission lines than would otherwise be possible, as well as additional options for future transmission expansions	Value can be identified through studies evaluating a range of futures that would allow for evaluation of "no regrets" projects that are valuable on a stand-alone basis and can be used as an element of a larger potential regional transmission build out	CAISO (Tehachapi) MISO MVP
8d. Increased fuel diversity and resource planning flexibility	Interconnecting areas with different resource mixes or allow for resource planning flexibility		
8e. Increased wheeling revenues	Increased wheeling revenues result from transmission lines increasing export capabilities.	Estimate based on transmission service requests or interchanges between areas as estimated in market simulations	SPP (RCAR) ITC-Entergy
8f. Increased transmission rights and customer congestion-hedging value	Additional physical transmission rights that allow for increased hedging of congestion charges.		ATC Paddock-Rockdale
8g. Operational benefits of HVDC transmission	Enhanced reliability and reduced system operations costs		

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