Filing Receipt

Received - 2021-07-22 02:16:30 PM
Control Number - 52268
ItemNumber - 11

Public Utility Commission of Texas

Memorandum

TO: Chairman Peter Lake
Commissioner Will McAdams
Commissioner Lori Cobos

Interested Parties

FROM: Connie Corona, Deputy Executive Director

DATE: July 22, 2021

RE: July 26, 2021 Work Session

Project No. 52268 – *Calendar Year 2021 - Workshop Agenda Items Without an Associated Control Number*

JULY 26, 2021 WORK SESSION

Topic 1: DSP to RTO Relationship – American Electric Power
Richard Ross, Director, Transmission Policy, AEP

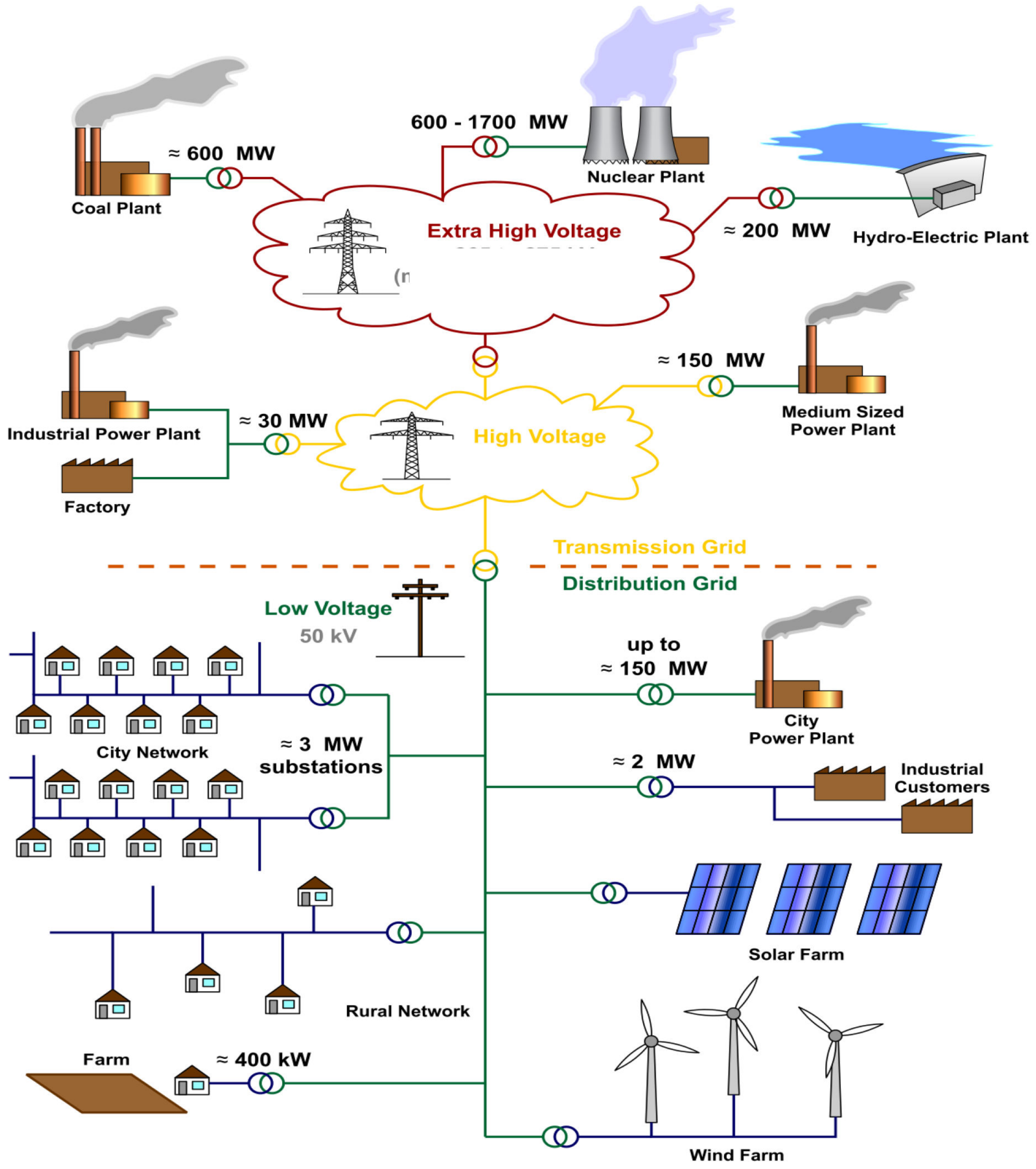
Topic 2: Existing ERCOT Load Shedding Process
Dan Woodfin, Senior Director, System Operations, ERCOT

Topic 3: Implementing a Load Shedding Directive – Oncor, CenterPoint, TNMP
- Oncor - Collin Martin, Senior Director Transmission Grid Operations and Liz Jones, VP Regulatory Affairs
- CenterPoint – Eric Easton, VP Real Time Operations and Patrick Reinhart, VP Regulatory Relations & Policy
- TNMP – Stacy Whitehurst, VP Regulatory Affairs

Topic 4: RGV Transmission Discussion – ERCOT, AEP, Sharyland Utilities
Warren Lasher, Senior Director, System Planning
Wayman Smith, Director, Transmission Planning, AEP
Michael Quinn, Vice President Operations, Sharyland Utilities

Capacity Deficiency Event – Transmission Operator View

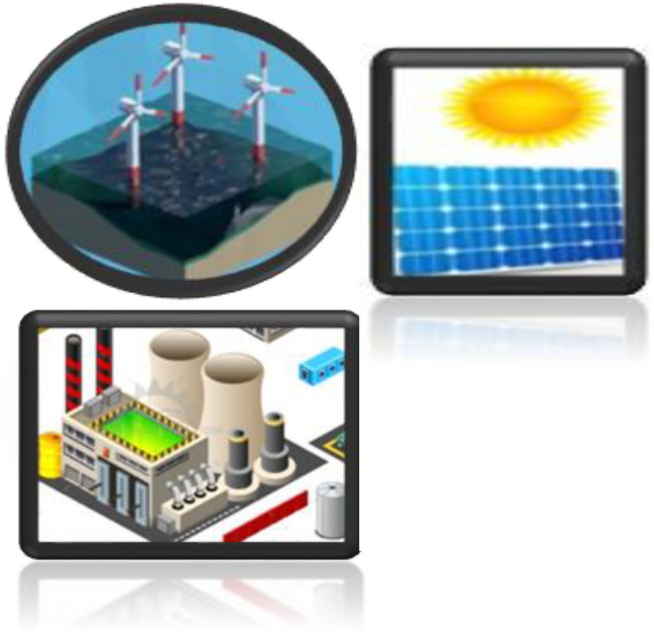
July 2021



Item 1: Balancing Authority (BA)

The responsible entity that integrates resource plans ahead of time, maintains Demand and resource balance within a Balancing Authority Area, and supports Interconnection frequency in real time

- **ERCOT is the BA in Texas**
- **The majority of the time the BA is focused on increasing or decreasing Generation to the system to match projected load**
- ***Generation Capacity Deficiency*** **flips the BA position to one of decreasing load to match available / stable generation**



Normal (+ or – Gen)

=

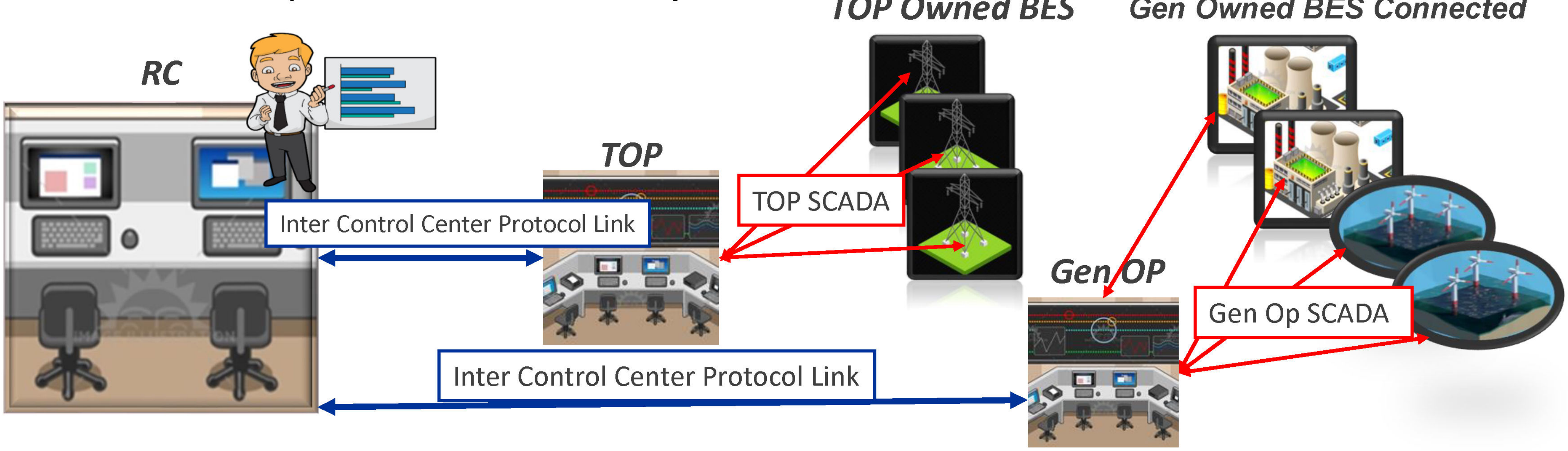
Generation Capacity Deficiency (- Load)

≠

Item 1a: Reliability Coordinator (RC)

The entity that is the highest level of authority who is responsible for the Reliable Operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The RC has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.

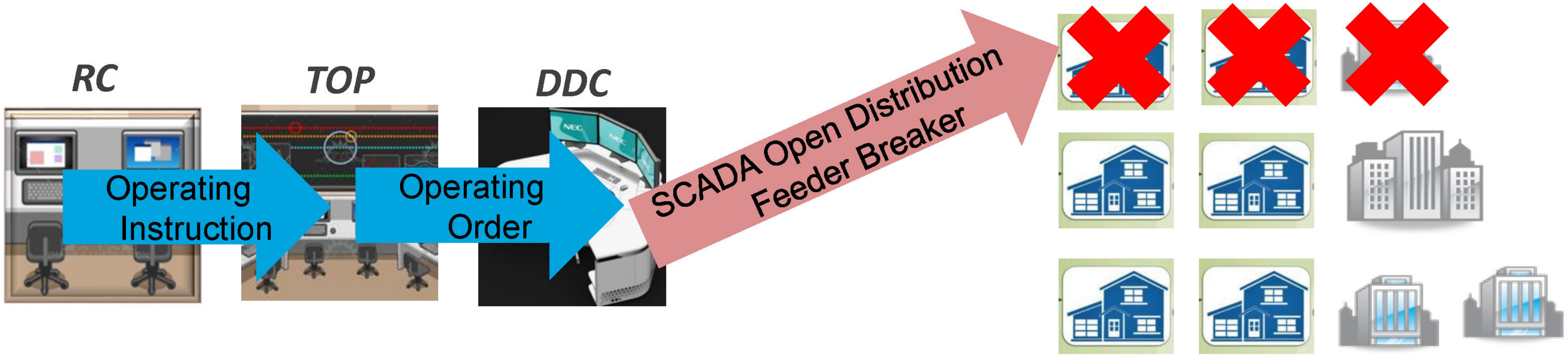
- **ERCOT is the RC in Texas**
- **The RC is focused on the reliability of the entire region**
- **The RC uses real time situational awareness tools to analysis the stability off the BES**
- **The RC works closely with all TOP's to ensure collaborative analysis and to ensure appropriate actions are taken to protect the overall reliability of the BES**



Item 2: Transmission Operator (TOP)

The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of transmission Facilities.

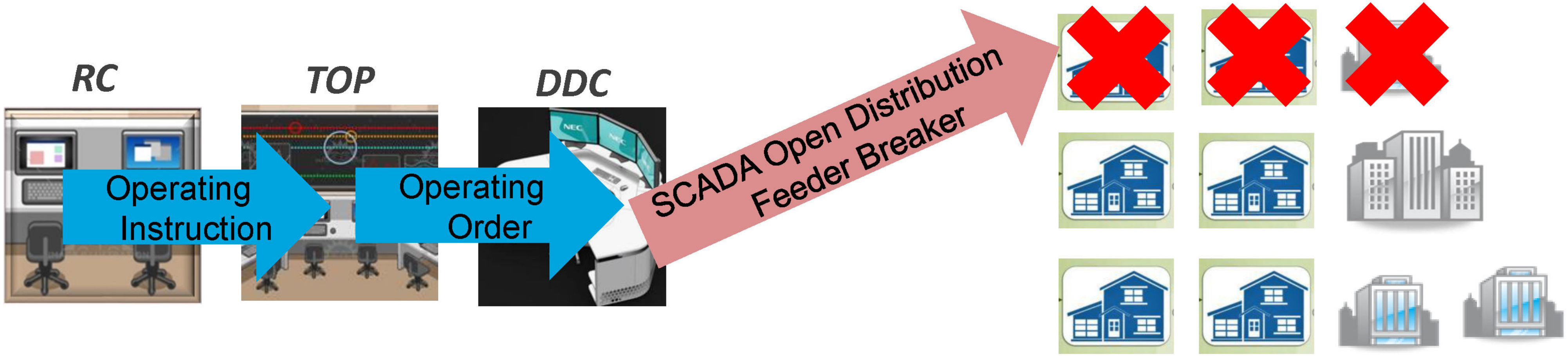
- **Generation Capacity Deficiency the Transmission Operator receives operating instructions from Reliability Coordinator (RC) to shed load and restore load based on predetermined allocation across the RTO**
  - **Allocation is based on Total TOP % of RTO load at Summer Peak**
  - **AEP Texas allocation in ERCOT is 8.7% of Total ERCOT load at the time Energy Emergency Alert 3 is declared**
  - **Allocation is provided to TOP in MW**
- **AEP (TOP) has preprogrammed SCADA tripping in the T SCADA / EMS tools to allow tripping of Distribution Feeder Breaker to "shed load" on a distribution circuit by AEP Texas (DP) Distribution Dispatch**



Item 2a: Transmission Operator (TOP)

The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of transmission Facilities.

- The RC communicates operating instruction (shed / restore) directly to the TOP via required voice communication protocols (COM-002) and phone circuits (all TCCs have primary and back up voice communication lines)
- The TOP issues operating orders to the DDC to shed load via internal communication protocols and phone circuits
- A significant amount of pre-Uri communications took place between RCs, TOPs and internally between TOP and DDC
- T SCADA EMS real time situational awareness tools and D SCADA OMS/DSM tools are identical in SPP and ERCOT



Item 3: Distribution Provider (DP)

Provides and operates the “wires” between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage.

- **Generation Capacity Deficiency - The AEP Texas (DP) manages the load shed plans and executes the final button push to shed customers, rotate outages and restore customers, as they are the closest to the customers and they are in the best position to convert the MW Operating Instruction into customer outages**
- **In the event AEP Texas is unable to execute the load shed at the distribution feeder breaker level in a timely manner, the Transmission System Operators will open Transmission equipment to drop the needed load**

Item 4: Training of NERC Certified / AEP Qualified Personnel

- NERC PER-005 establishes training criteria for TOP NERC Certified System Operators and Regional Reliability Coordinators.
- Per PER-005, AEP TOP has identified several tasks performed during Capacity Deficiency as a Reliability Related Task
  - This requires the TOP System Operator to demonstrate task performance before being assigned the task(s).
- AEP's Systematic Approach to Training requires training on Capacity Deficiency and BES Emergencies on an annual basis for the TOP System Operator; which includes but not limited:
  - 2 Hours of focused Capacity Deficiency e- Learning
  - Min of 3 hours of focused Capacity Deficiency simulation training
- AEP Texas DP Distribution Dispatcher (outside of NERC PER-005 requirement) are trained by AEP Texas on the tools and processes associated with executing a load shed operating instruction.

Item 5: Positives / Improvements

Positives:

- Pre-Event planning and action plan discussions
- Operating Instructions executed in a timely manner
- Restoration executed in a timely manner when Gen capacity was restored
- System Collapse Avoidance - (No Brown Out and No Black Out)

Improvements:

- More field devices tied to Distribution SCADA tools
- More Smart Grid infrastructure on D Wires circuits

Appendix

- ERCOT vs SPP
  - Both experienced Gen Cap Deficiency
  - SPP had more flexibility with outside RTO imports than ERCOT, which is limited to DC ties
  - ERCOT and SPP are registered as both the RC and BA
  - ERCOT is registered TOP and uses CFR to delegate responsilbities; SPP is not a registered TOP and AEP carries all TOP responsibilities
    - AEP EDOps has an excellent peer to peer working relationship with both ERCOT and SPP
  - Load Shed related actions taken were identical (All NERC standards were followed in both areas)
  - AEP allocation in ERCOT – 8.7% (third highest) in SPP 16.8% (highest)
  - At peak load shed - AEP Shed of 1740 MW in ERCOT and 456 MW in SPP

Questions/Comments

Existing Involuntary Load Shed Processes

Dan Woodfin
Senior Director, System Operations

PUC Workshop
July 26, 2021

Overview

- When there is not enough generation available to serve consumers' demand for electricity, and all other solutions available to ERCOT have been exhausted, ERCOT will instruct utilities to reduce power on the system to balance supply and demand. This is referred to as load shed.

- ERCOT determines how much power needs to come off the system.

- Distribution Service Providers (DSPs) are obligated to implement the load shed.
  - DSPs determine how to implement the load shed.
  - DSPs need to be represented by an entity with 24x7 operations who has hotline communications with ERCOT and control over breakers - typically a Transmission Operator (TO).
  - The load shed amounts are allocated in the ERCOT Operating Guides to the TOs.

Current Load Shed Percentage Table (7/1/2021)

Transmission Operator	2020 Total Transmission Operator Load (%MW)
AEP Texas Central Company	8.23
Brazos Electric Power Cooperative Inc.	5.11
Brownsville Public Utilities Board	0.36
Bryan Texas Utilities	0.51
CenterPoint Energy Houston Electric LLC	24.78
City of Austin DBA Austin Energy	3.55
City of College Station	0.28
City of Garland	0.76
City of Lubbock	0.62
CPS Energy (San Antonio)	6.47
Denton Municipal Electric	0.48
GEUS (Greenville)	0.15
Golden Spread Electric Cooperative Inc.	0.38
Lamar County Electric Cooperative Inc.*	0.07
LCRA Transmission Services Corporation	6.05
Oncor Electric Delivery Company LLC	36.16
Rayburn Country Electric Cooperative Inc. DBA Rayburn Electric	1.38
South Texas Electric Cooperative Inc.	2.00
Texas-New Mexico Power Company	2.66
ERCOT Total	**100.00**

Per ERCOT Operating Guides:

- Percentages for load shedding are based on the previous year's Transmission Operators' peak loads, as reported to ERCOT.
  - These percentages are reviewed by ERCOT and modified annually.

- Each block of load shed is required to be shed within 30 minutes; if block size is above 1,000 MW, it may take longer to implement.

Load Shed Survey for Summer 2021

- ERCOT requested information from Transmission Operators on their load shed capabilities for summer 2021:

At System Load =	60 GW	70 GW	80 GW
Total load that can be shed:	23	27	31
- Within 5 minutes	4.7	5.4	6.3
- Within 10 minutes	5.9	6.8	7.7
- Within 15 minutes	13	16	18
- Within 30 minutes	23	27	31

- The total amount of load that can be shed on a TO's system may be limited for the following reasons:
  - To avoid the use of circuits that provide underfrequency load shed protection
  - To avoid circuits that serve critical loads or are on networked distribution
  - Does not typically include the use of transmission-connected/industrial loads

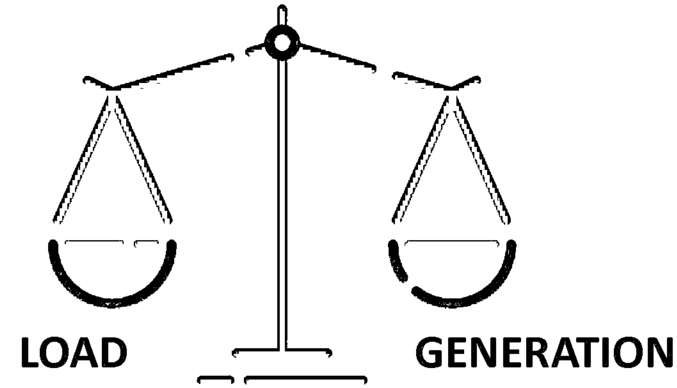
- Available load shed may vary based on the specific weather conditions.

Implementing a Load Shed Directive

WE DELIVER.

ONCOR®

Short Supply Basics



ERCOT is responsible for maintaining the consumer demand (load) and generation balance at all times (24/7/365) to maintain a system frequency of 60 Hz.

- If there is insufficient generation to serve system load, the frequency declines.
- If a decline in frequency is not stopped, the entire ERCOT system will black out. A black out is **much worse** than short supply.
- Disconnecting load is the last resort option to maintain frequency when there is a shortage of generation.

T&D Companies like Oncor are responsible for taking immediate action to disconnect load as instructed by ERCOT.

ONCOR.

Priorities During a Load Shed Event

1. **Prevent a system black out**

2. **Prioritize continuity of power to exempt customers**

3. **If operationally possible, rotate outages equitably among non-exempt or remaining customers**

Mechanics of Load Shed

Must have a documented plan:

- Load share determined by Operating Guide
- Each entity must manage various load and circuit types
  - Under-Frequency Load Shed (UFLS)
  - Exempt
  - Manual load shed
  - Transmission connected
- Timing

How to execute the plan:

- Communication
- Load shed tools – manual vs automatic
- SCADA vs manual
- Load rotation
- Training

Critical Customer vs Exempt Customer

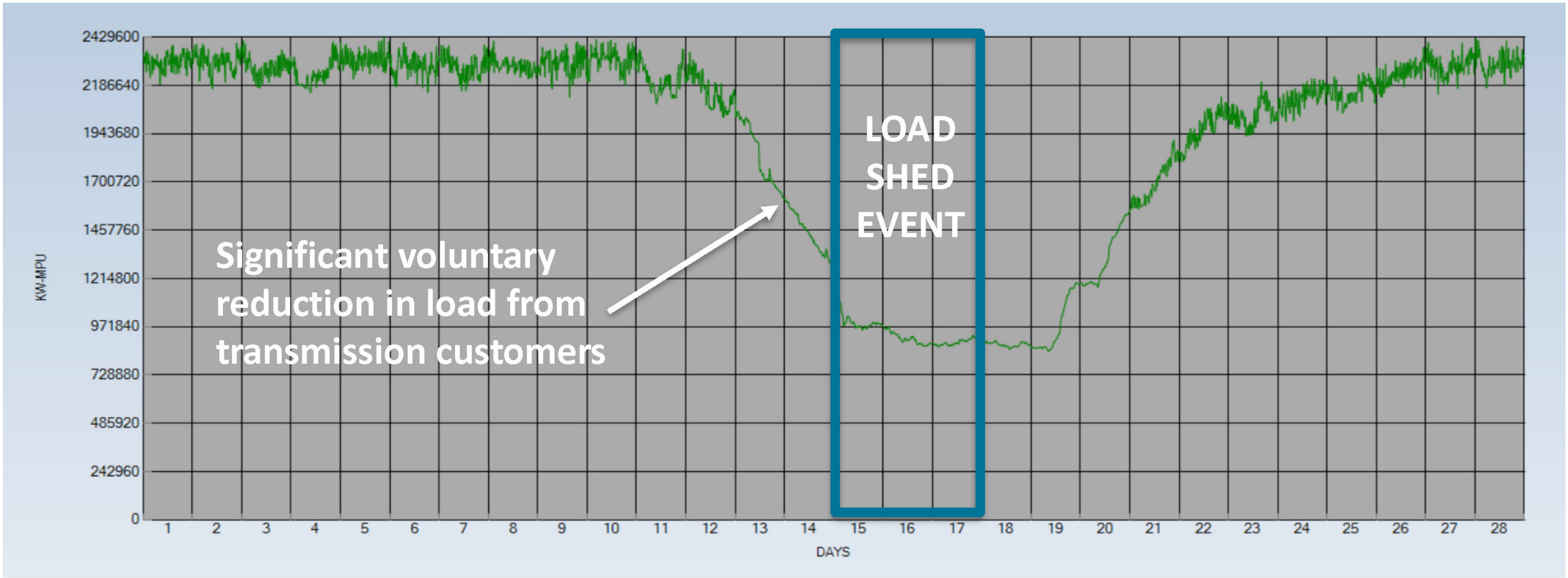
Critical Customer Categories:

- Critical Care Residential
- Chronic Condition Residential
- Critical Load Industrial
- Critical Load Public Safety

Certain customer types within the Critical Load Industrial and Critical Load Public Safety categories are exempted from rotational load shed.

- 911 Center
- Emergency Broadcast
- Gas (Supporting Generation)
- Gas Control Center
- Major Airport
- Oncor/ERCOT Operation Facility
- Distributed Generation Major Exporter
- Hospital
- Military Installation

Transmission Customer Load Trend in February



Oncor's transmission customers voluntarily reduced load by 48% in anticipation of the February event.

- Load reduced from 2,300 MW to 1,200 MW prior to the event and from 1,200 MW to 900 MW during the event.

How to Increase Diversity in Load Rotation

The available "pool" of rotatable load must be increased to improve diversity in load rotation. Options include:

1. Increase the volume of circuits with remote control capability.
2. Dynamically adjust the volume of feeders reserved for UFLS based on real-time loading levels and magnitude of load shed.
3. Remotely enable/disable UFLS feeder capabilities such that the UFLS role is rotated and a higher percentage of feeders are subject to inclusion in load shed.
4. Further segmentation and automation of the distribution system to sectionalize exempt loads at pre-defined points.
5. Adapt and substantially re-deploy and re-architect Advanced Metering Infrastructure (AMI) to manage load shed on a premise basis.

Any efforts to increase diversity in load rotation must properly mitigate higher risks to system operations and impacts to customers.

AMI Load Shed Considerations

- Meters with remote disconnect/reconnect capabilities are currently limited to small/medium single-phase residential premises
- Speed of executing load shed during a system event
- Meter network resiliency
- Control system resiliency
- Ability to rotate shed load
- Ability to scale for large load shed events

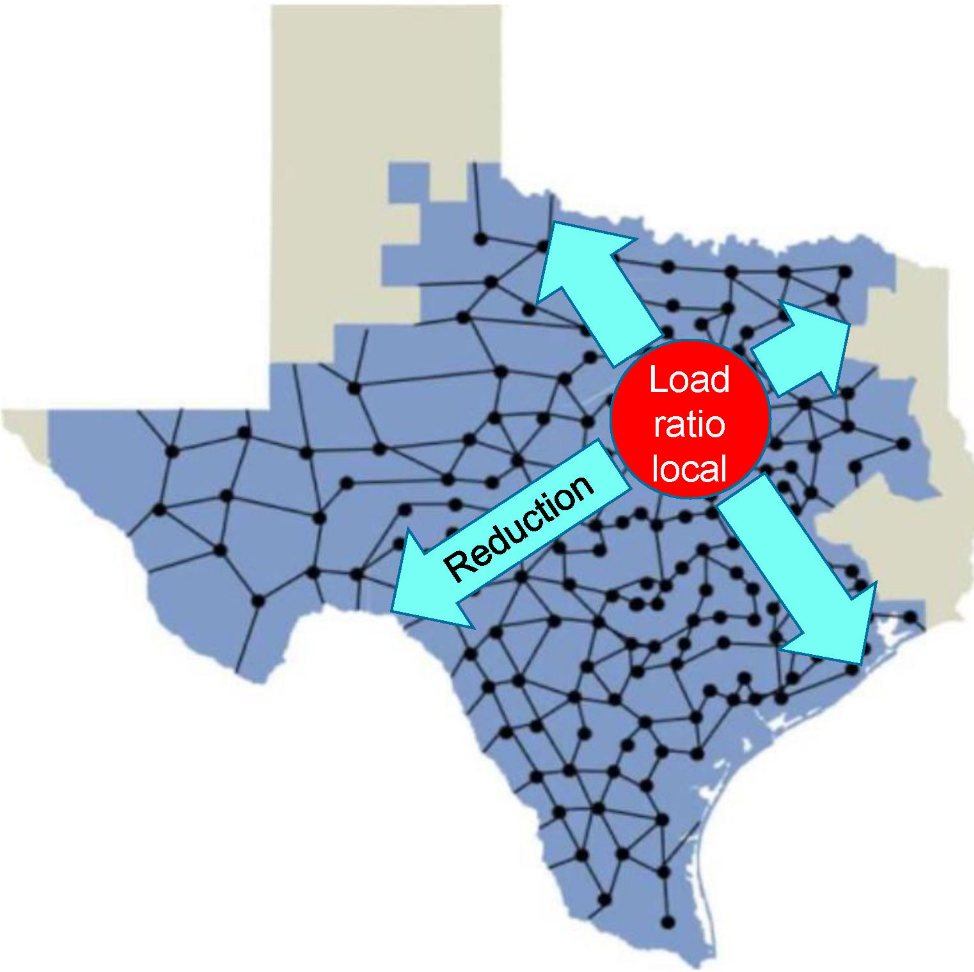
ONCOR

Industrial Customer Allocation

- Industrial load reductions are not performed by the Transmission Service Providers (TSPs)

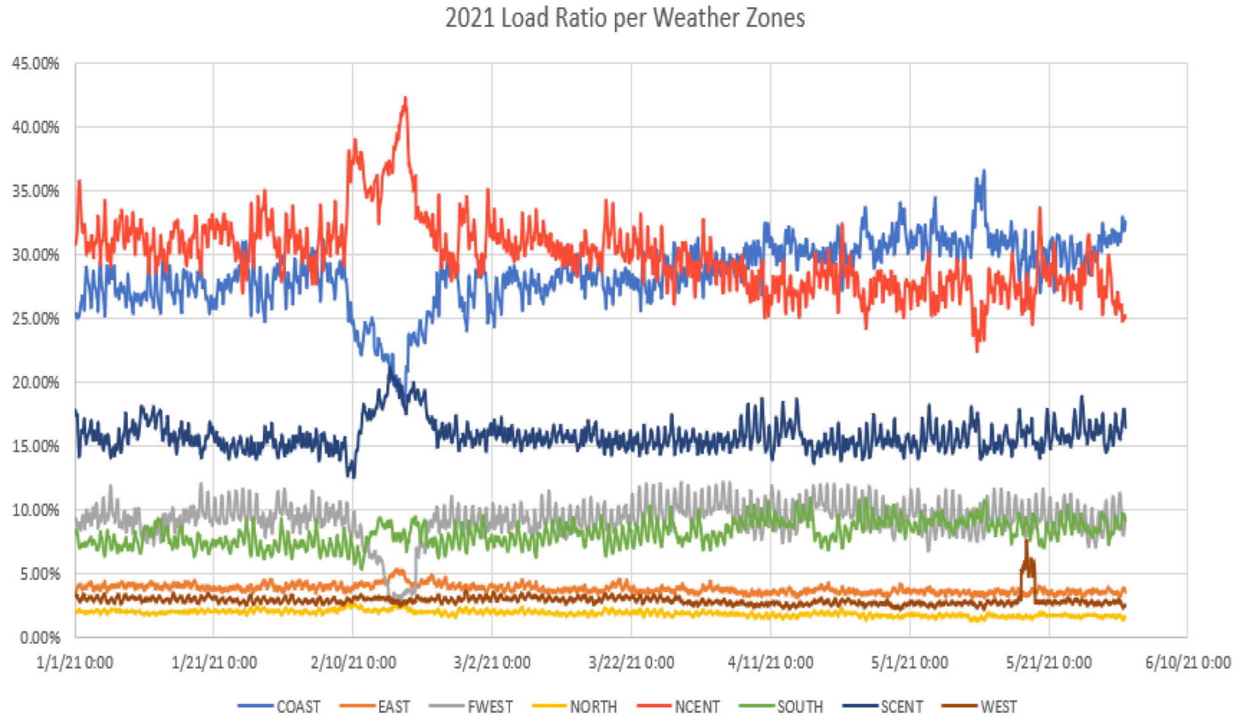
- Industrial loads are included in the load ratio share which determine load shed obligations by TSP

- Load reductions from industrial customers are not reflected in the fulfillment of load shed obligations



Real-time Load Ratio Share Differences

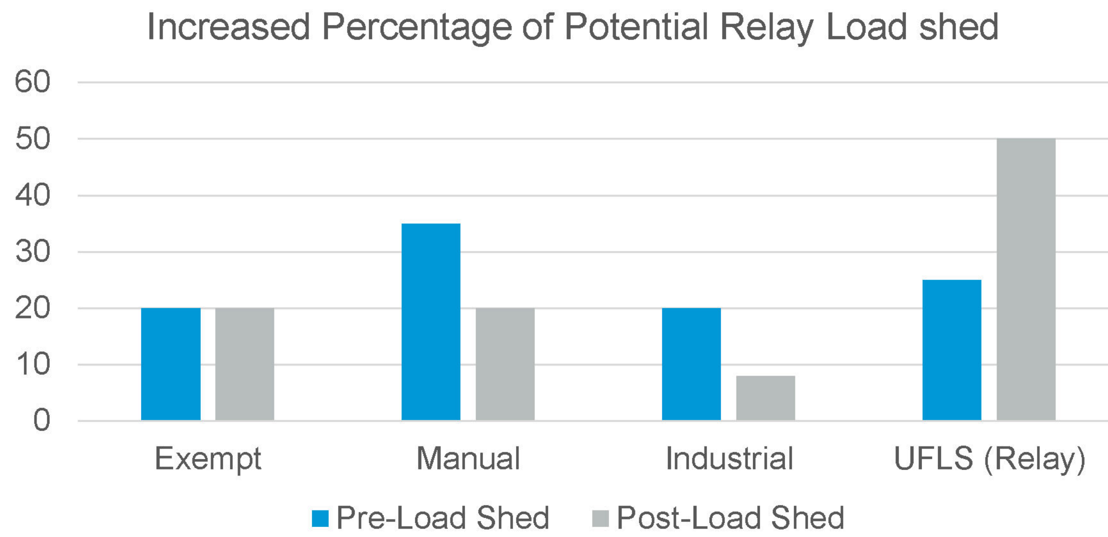
- Presently, a single load shed allocation based on summer load levels is used <u>for the entire year</u>
- Regional load allocations can change significantly throughout the year
- Study is needed to determine the level of variability and resulting impacts

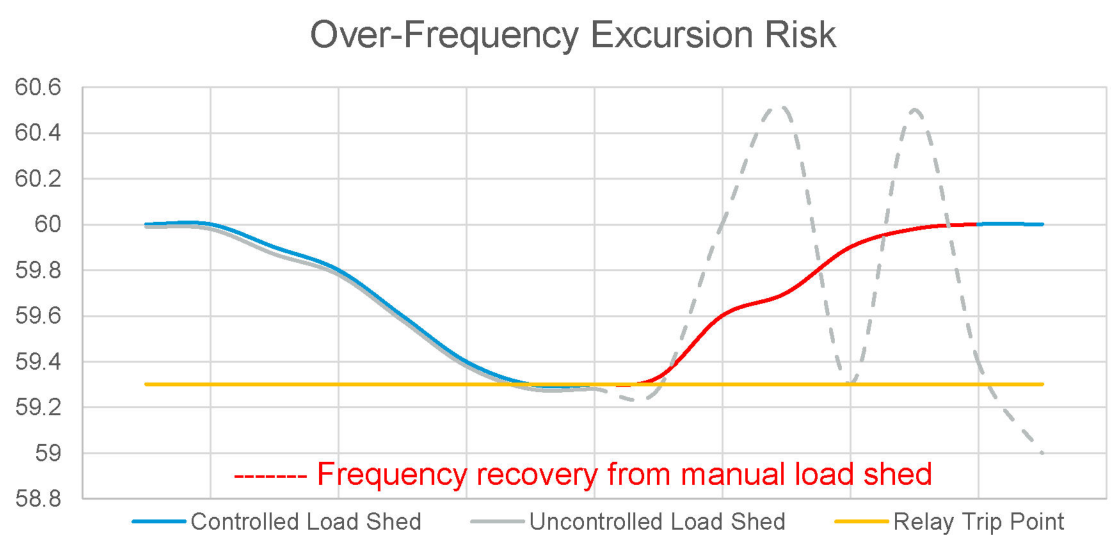


	COAST	EAST	FWEST	NORTH	NCENT	SOUTH	SCENT	WEST
Max	36.55%	5.22%	12.09%	2.62%	42.31%	10.87%	21.11%	7.54%
Min	18.24%	3.08%	2.67%	1.25%	22.40%	5.32%	12.48%	2.16%
Average	28.52%	3.76%	9.17%	1.84%	29.98%	8.12%	15.77%	2.84%

Under-Frequency Load Shed (UFLS) Allocations

- Manual load shed feeders
  - Feeders initially used to reduce load and maintain grid stability
- Under-frequency Load Shed feeders
  - Pre-determined feeders with specialized relaying for instantaneous load reduction
  - Must maintain a minimum of 25% of load in relay load shed sub-set





Impact of Exempt Customers on Load Shed

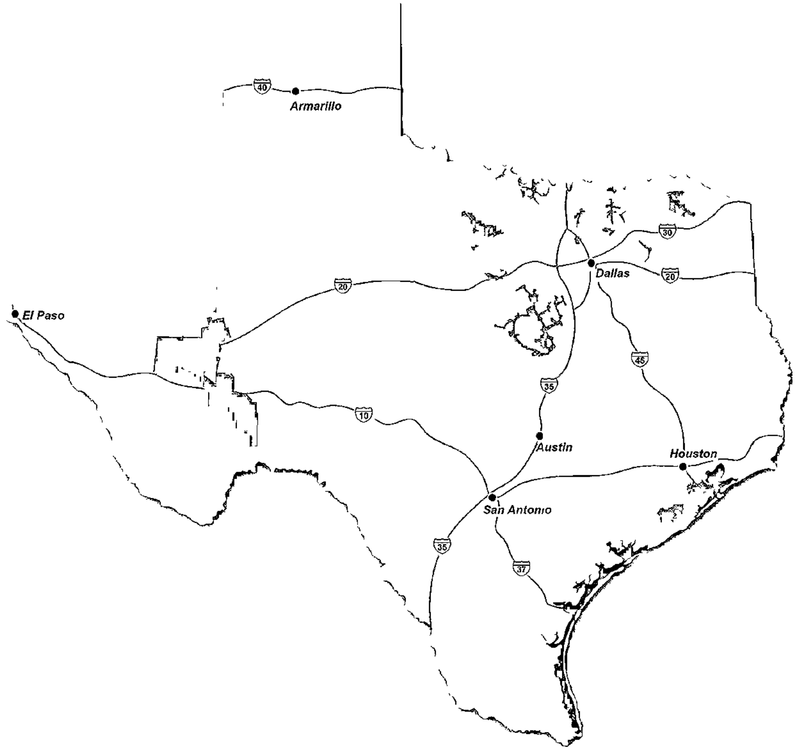
- **Summer 2020 MW at ERCOT Peaks**
  - June = 1,815 MW*
  - July = 1,952 MW*
  - Aug. = 1,988 MW*
  - Sept. = 1,837 MW*

- **Winter Storm Uri 2021**
  - Feb. 14 @18:30= 1,754 MW**

** Source: ERCOT load report

TNMP transmission 4CP load ≈ 550 MW

*Source: ERCOT 4CP report



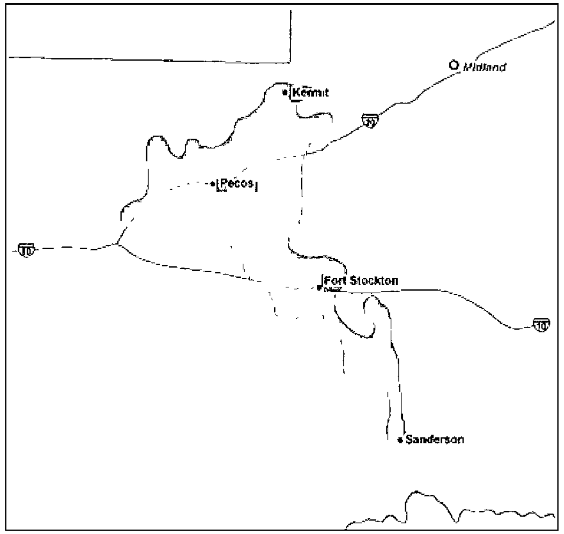
TNMP
Texas-New Mexico Power

Load Shed - Service Territory Challenges

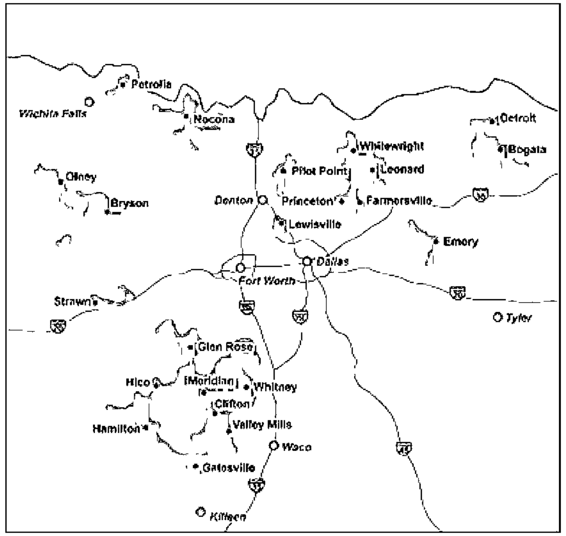
- Availability of SCADA in all substations
- Impact of Emergency Response Service participants
- Under Frequency load shed feeders

SCADA - Supervisory Control and Data Acquisition

Texas-New Mexico Power

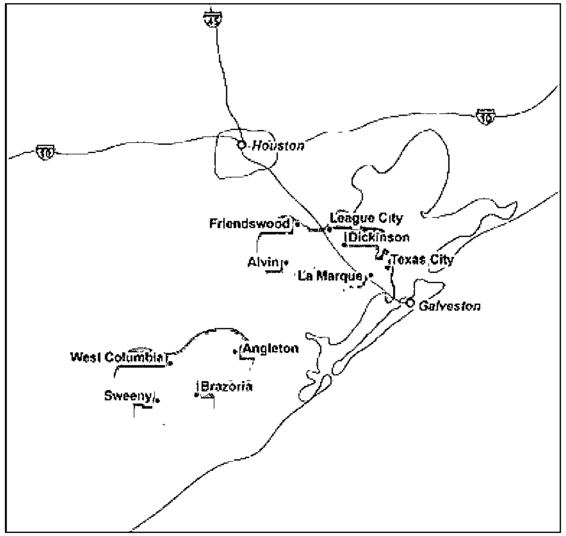


West Texas
20,000 homes & businesses



North Texas
76,000 homes & businesses

Central Texas
26,000 homes & businesses



Gulf Coast
138,000 homes & businesses

Transmission Planning in ERCOT

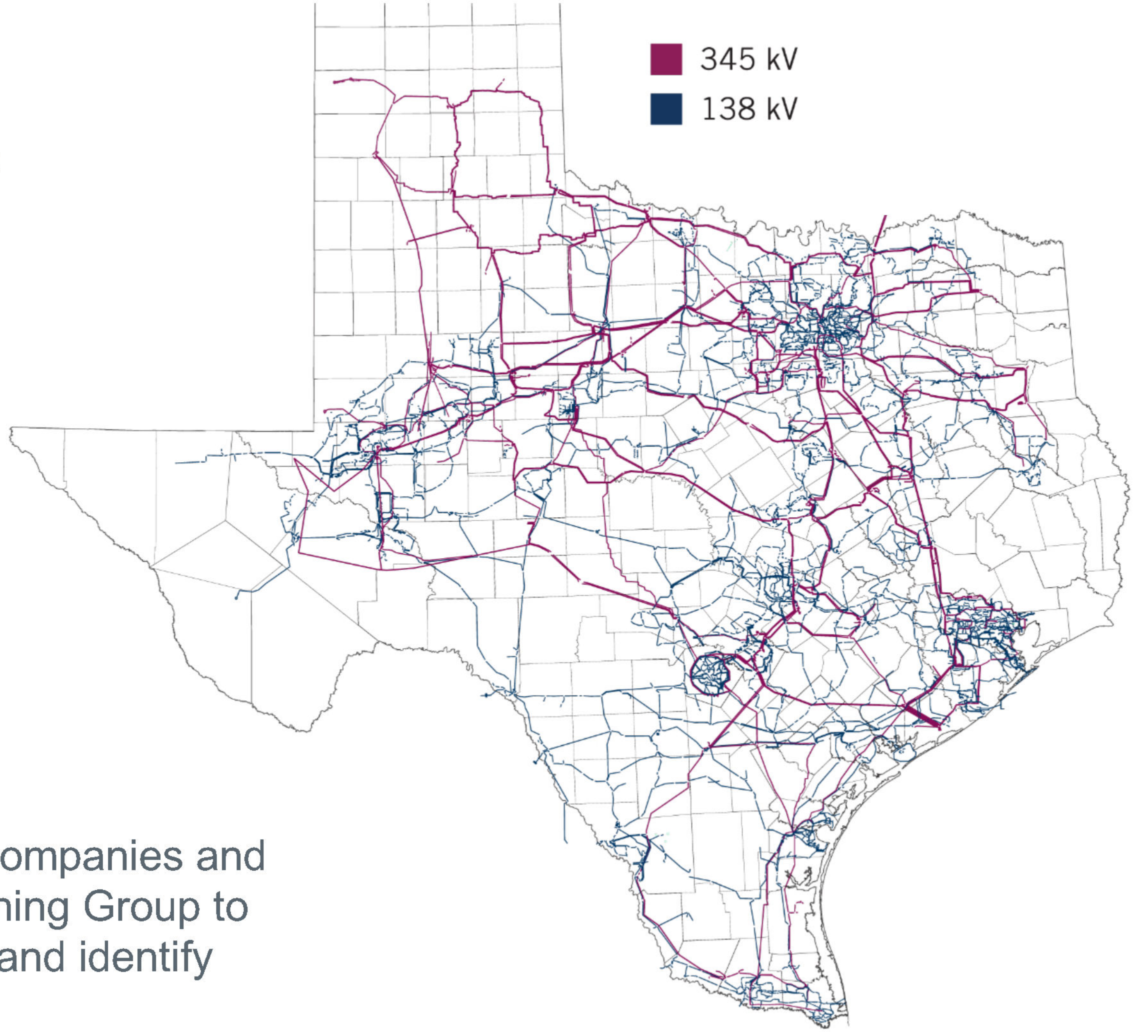
Warren Lasher
Senior Director, System Planning

PUC Workshop
July 26, 2021

The ERCOT Transmission System

The ERCOT transmission system connects 700+ generating units to consumers throughout most of the state of Texas.

The growing economy and increasing population are driving growth in electricity demand, causing a need for increased transmission capacity. In addition, the changing generation fleet is causing shifts in how power flows across the transmission system, resulting in new constraints.



ERCOT works with transmission companies and stakeholders in the Regional Planning Group to assess these transmission needs and identify suitable project solutions.

Transmission Planning Criteria

- Transmission projects are evaluated based on reliability need and economic benefit.
  - **Reliability Projects**
    - Projects that are required to reliably serve load (as per NERC standards and ERCOT protocols).
    - These projects are evaluated based on effectiveness and estimated cost.
  - **Economic Projects**
    - ERCOT currently evaluates projects based on production cost savings (fuel costs and other variable costs) as per Subst. Rule 25.101.
    - If expected annual production cost savings resulting from a project are greater than the incremental annual revenue requirements charged to consumers, the project meets the economic criteria.
- Both criteria reflect an inadequacy of the transmission system to deliver power from the generators to load.
  - Reliability projects resolve situations where there are no possible generation alternatives to reliably serve load.
  - Economic projects resolve situations where there are possible generation solutions, but only from higher-cost units.

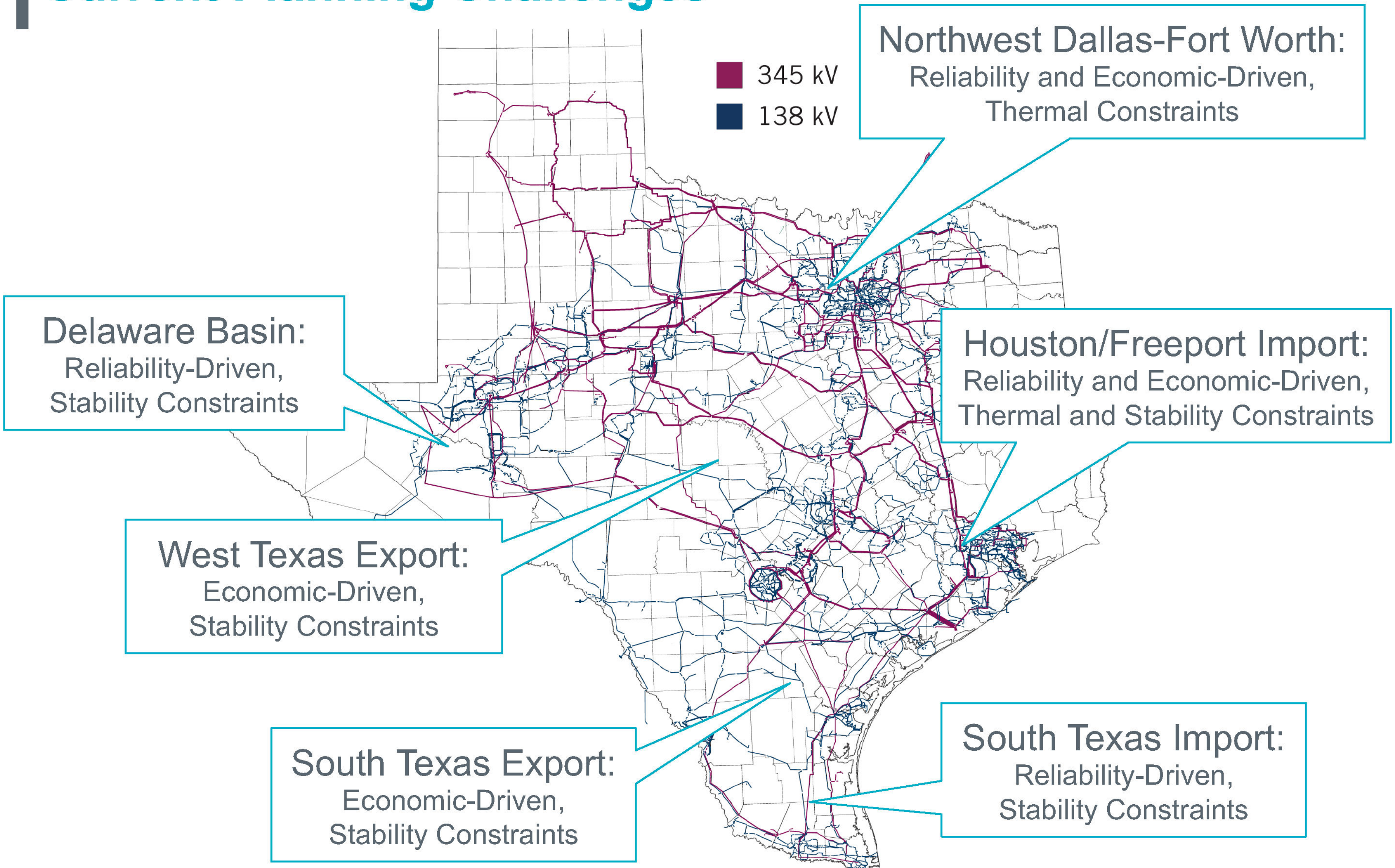
Transmission Project Review Process

1.	Proposal	ERCOT staff, Transmission Owner or Market Participant
2.	Independent project review	ERCOT
3.	Engineering and routing	Transmission Owner
4.	Certificate of Convenience and Necessity approval	Public Utility Commission of Texas
5.	Construction	Transmission Owner

Generally within 6 Years

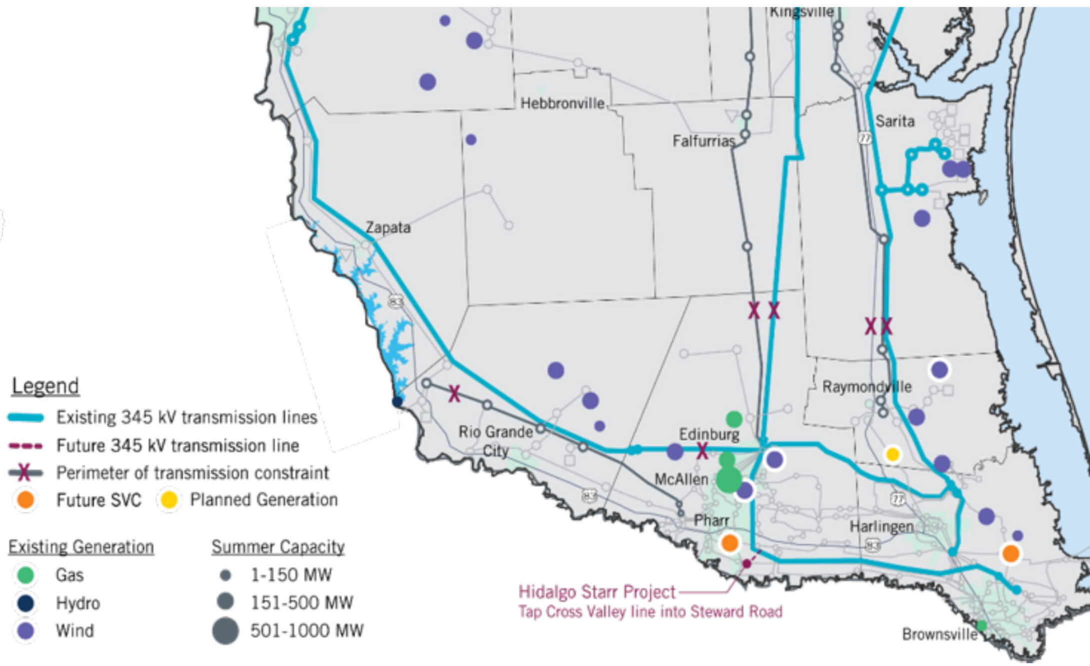
Annual studies are conducted to determine system needs within a six-year planning horizon. Longer-term studies are conducted every other year to ensure that near-term planning decisions are informed by long-term system trends.

Current Planning Challenges



South Texas & the Lower Rio Grande Valley

- ERCOT continues to work closely with transmission providers in the Lower Rio Grande Valley to help keep up with the growing region’s electricity needs.
- Although the region meets transmission planning reliability criteria, operational challenges are still a concern.

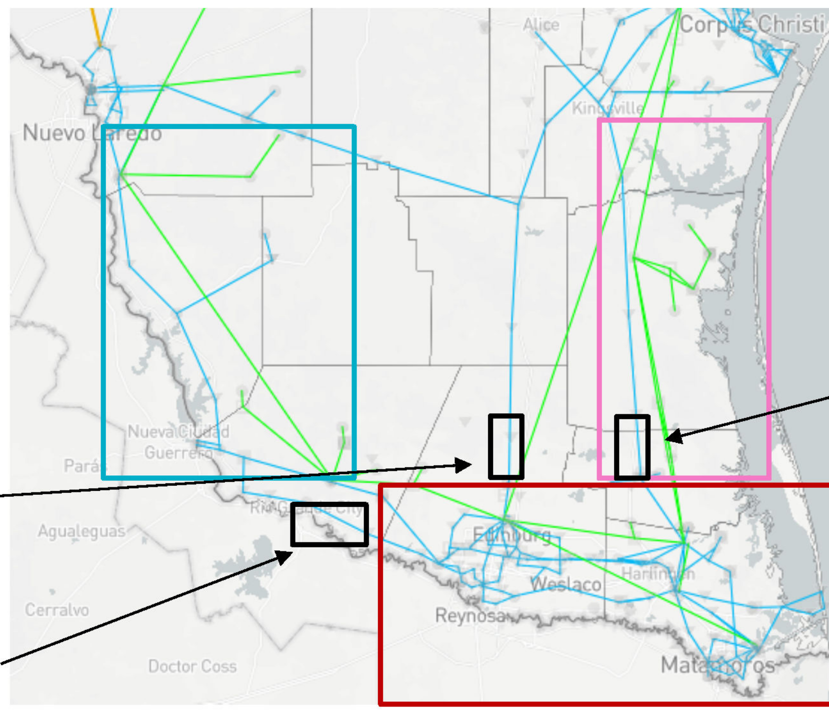


Import and Export Limitations in South Texas

- Multi-circuit transfer limits (often caused by complex grid stability issues) are modeled as “Generic Transmission Constraints.” Seven of the 16 ERCOT Generic Transmission Constraints are in South Texas and add to the complexity of reliably operating the grid.

North Edinburg - Lobo GTC (345kV)

Nelson Sharpe – Rio Hondo GTC (345-kV)



Raymondville – Rio Hondo GTC (138-kV)

RedTap GTC (138-kV)

Zapata - Starr GTC (138-kV)

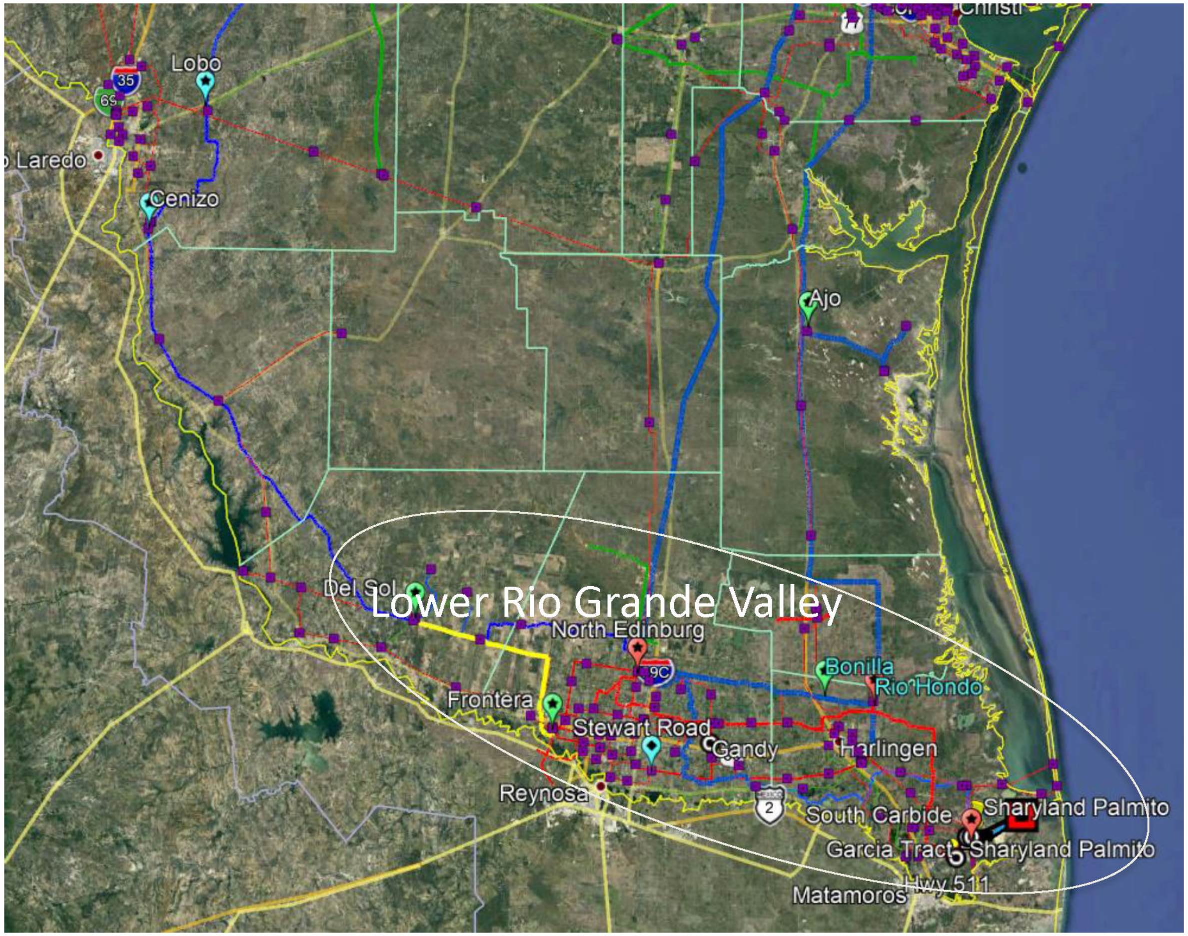
Valley Import & Export GTC (345-kV & 138-kV)

For visualization purposes only. Map does not represent exact GTC interfaces.

Lower Rio Grande Valley Area

- ERCOT intends to work with the local transmission owners to complete a review of project options for the Valley by the end of 2021.
- This review will be informed by planning studies conducted for the Permian Basin Region:
  - Both regions are on the edge of the ERCOT system.
  - Both regions have unique operational challenges.
  - ERCOT has adapted some of its planning assumptions to account for the operational challenges in the Permian Basin. Some of these adaptations are appropriate for the ongoing studies of the Valley region.
- Transmission circuits serving the Valley region are also subject to the threat of tropical storms. Recently passed Senate Bill 1281 (87R) directs ERCOT "…to assess the grid's reliability in extreme weather scenarios," and to "…recommend transmission projects that may increase the grid's reliability in extreme weather scenarios."

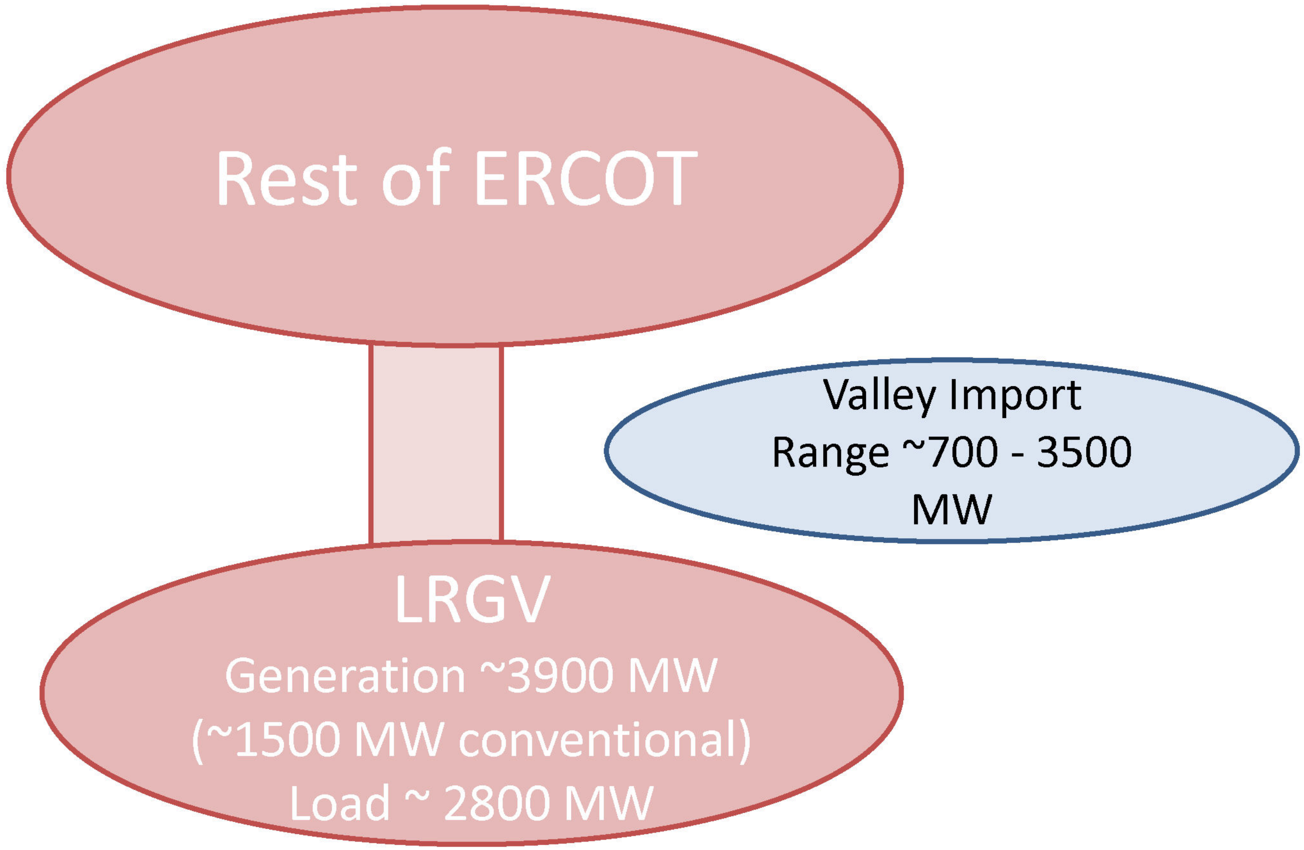
Rio Grande Valley



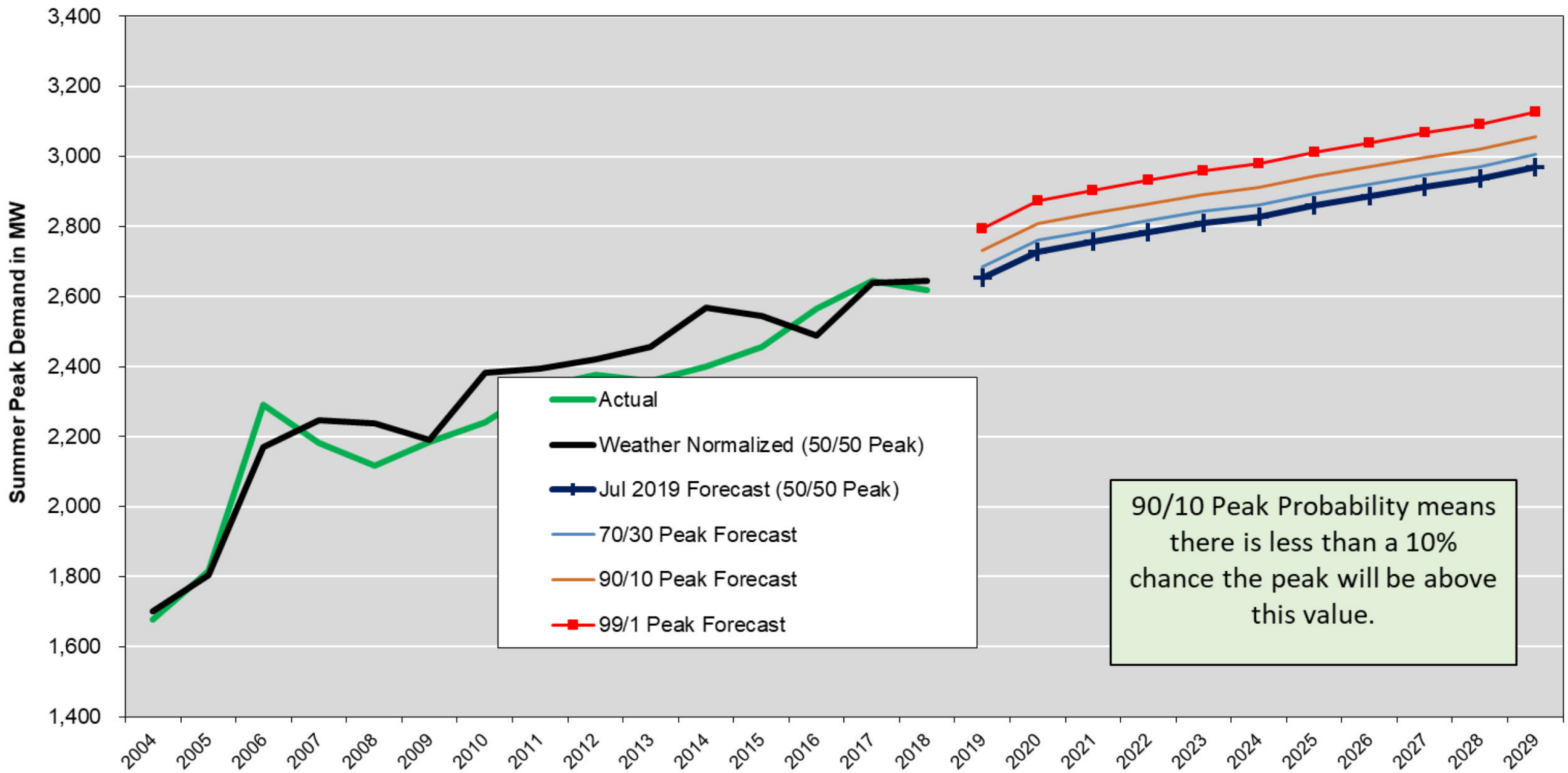
BOUNDLESS ENERGY℠

BOUNDLESS ENERGY℠

Generation/Load & Interface Limits



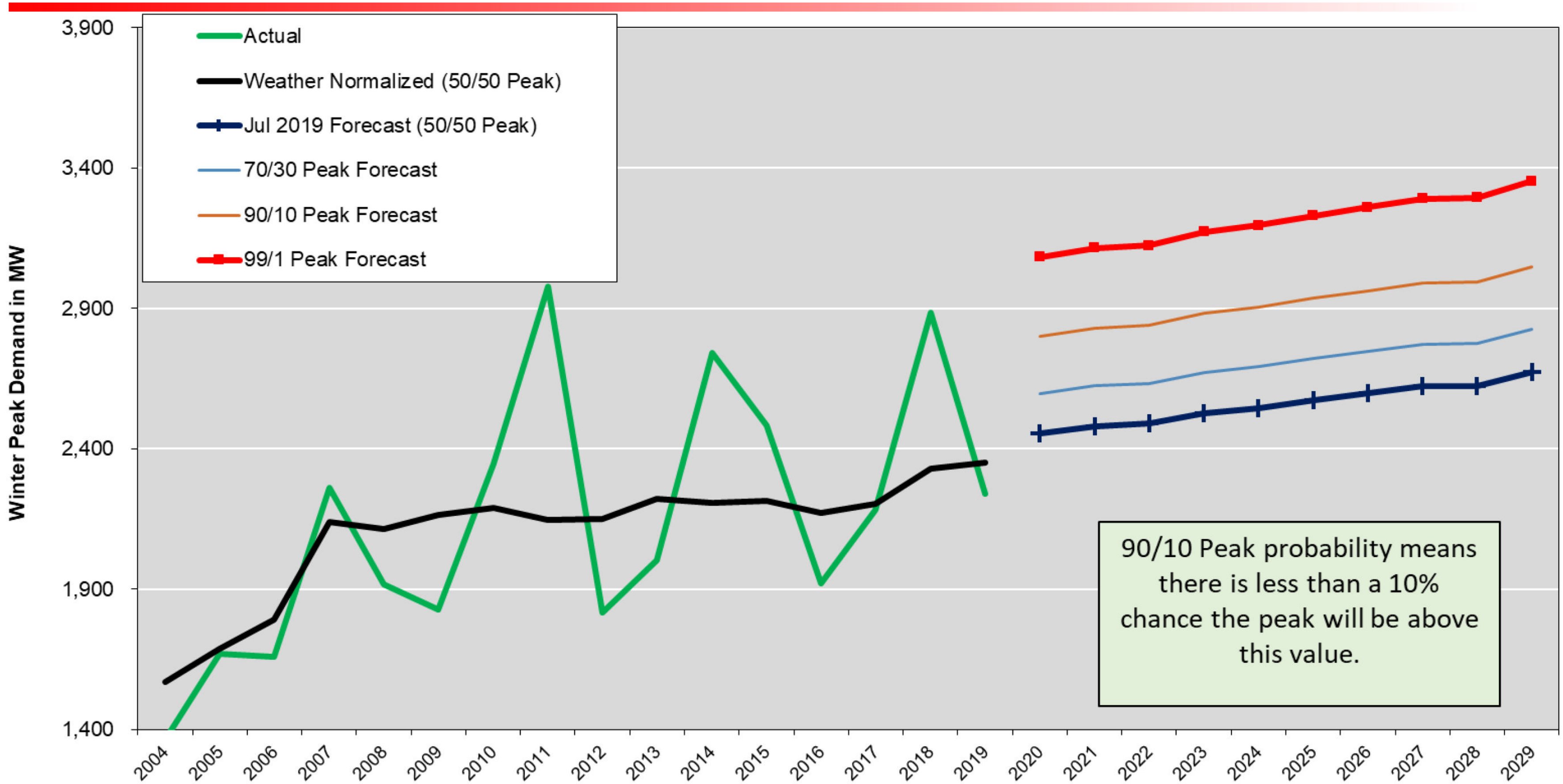
Texas Valley Area Summer Peak Demand at Varying Probability Intervals
2019 Load Forecast



Peak Prob	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
50/50	2,654	2,727	2,756	2,784	2,809	2,829	2,859	2,885	2,912	2,936	2,969
70/30	2,685	2,760	2,789	2,818	2,843	2,863	2,894	2,920	2,947	2,971	3,005
90/10	2,731	2,807	2,837	2,866	2,891	2,912	2,943	2,970	2,997	3,022	3,056
99/1	2,795	2,872	2,903	2,932	2,958	2,979	3,011	3,039	3,067	3,092	3,127

Texas Valley Area Winter Peak Demand at Varying Probability Intervals

2019 Load Forecast



Peak Prob	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029
50/50	2,455	2,481	2,489	2,528	2,546	2,574	2,598	2,622	2,625	2,672
70/30	2,597	2,624	2,633	2,673	2,692	2,722	2,747	2,773	2,776	2,825
90/10	2,801	2,830	2,839	2,883	2,904	2,936	2,963	2,991	2,994	3,047
99/1	3,082	3,115	3,125	3,173	3,196	3,231	3,261	3,292	3,295	3,354

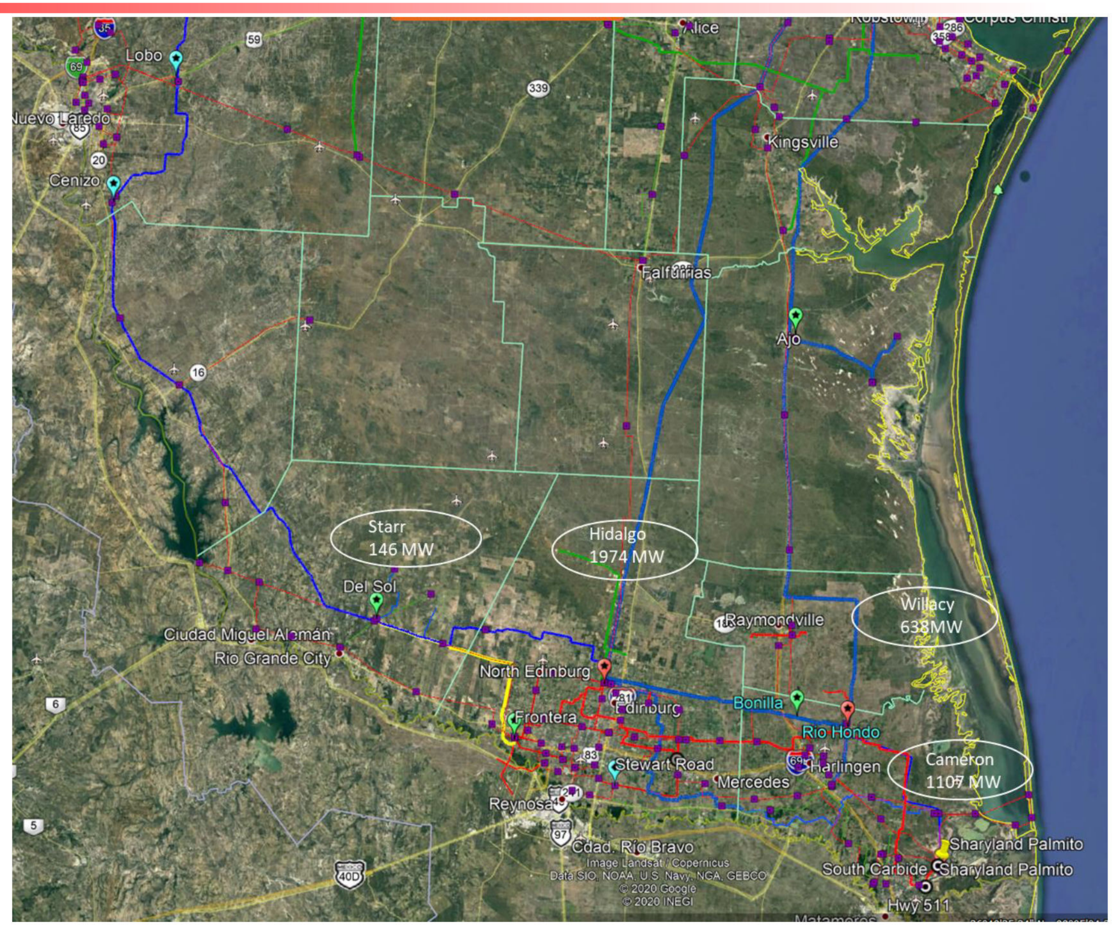
AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY℠

Current Installed Capacity in Lower Rio Grande Valley

Total – 3865 MW

Breakdown

Wind – 2001 MW
Conventional – 1526 MW
Other (Batteries and Hydro) – 338 MW



AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

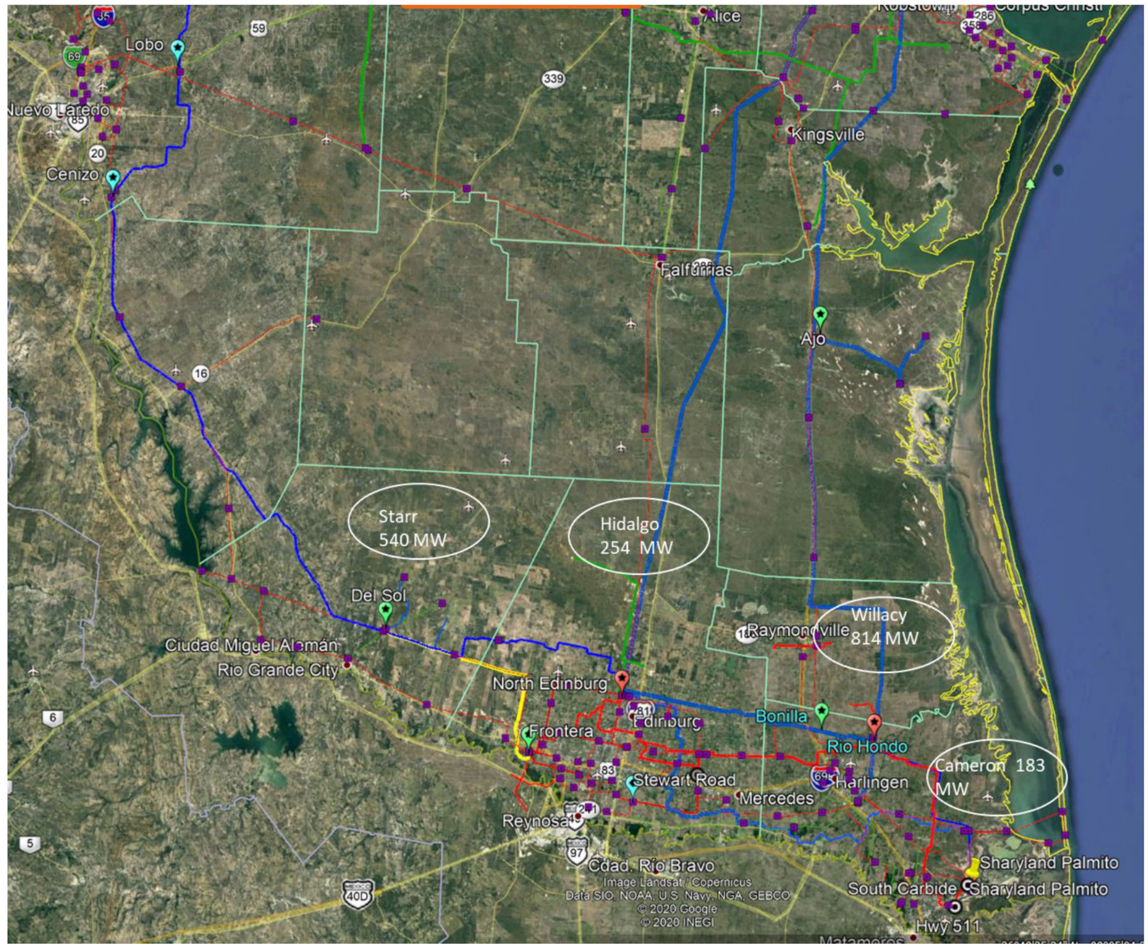
Planned Generation

Starr:
540 MW (Solar and Wind)

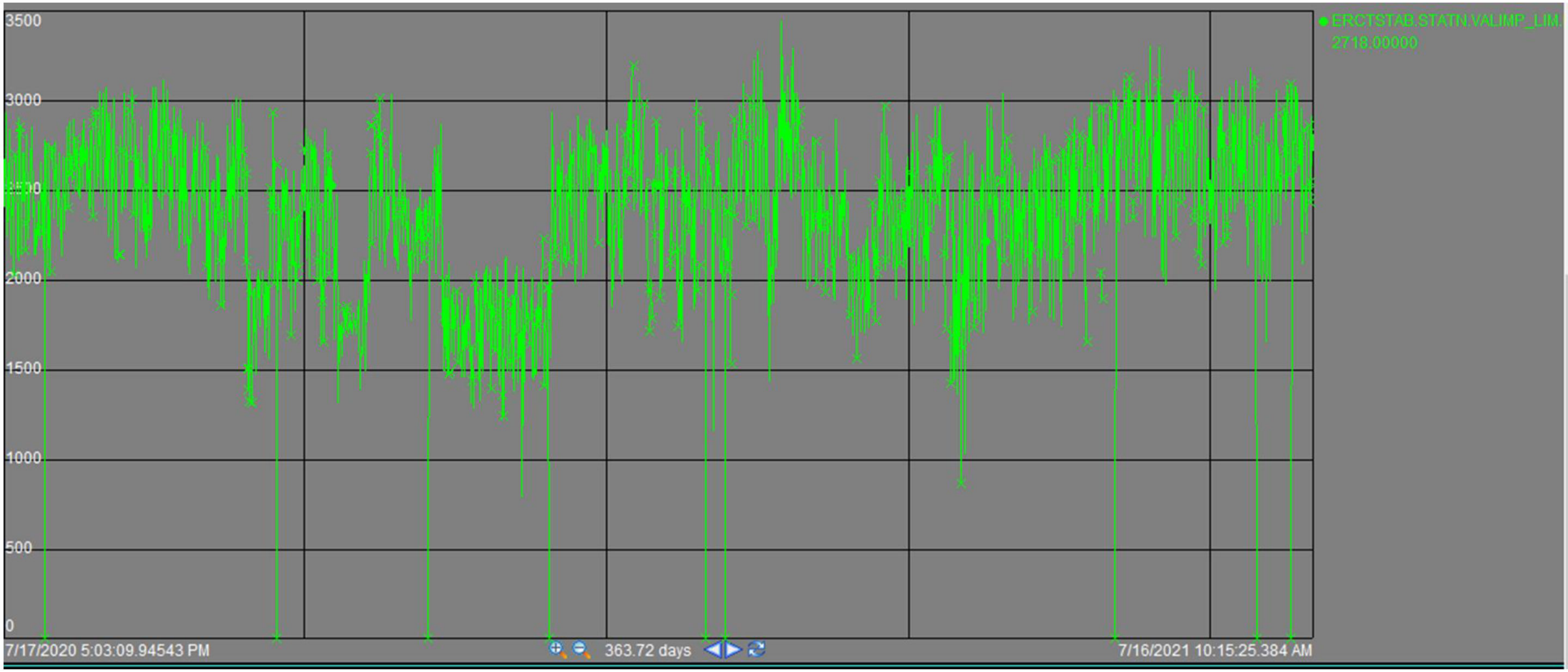
Hidalgo:
254 MW (Railroad DC Tie and Wind)

Cameron:
183 MW (Wind)

Willacy:
814 MW (Wind)



Real-Time Valley Import Limits



RGV/South Texas Challenges

- Load Pocket (reliant upon imports to maintain reliability during high load periods)

- Generation Pocket (potential export issues particularly during light load periods)

- Higher load growth area
  - Potential for very large spot load additions (LNG, other industrial loads) but available capacity is limited
  - Winter loads very sensitive to temperature (winter peak can exceed summer peak)

- Coastal Environment
  - Impact on facility condition
  - Potential for severe weather

- High penetration of Inverter Based Resources (IBR)
  - Inverters convert DC to AC or AC to DC
  - Wind resources employ inverters in order to synchronize output to the grid or optimize their operation
  - Inverters can introduce disturbances on the grid below 60 Hz (sub synchronous)

- Series compensated transmission lines
  - Series capacitors installed on the 345kV lines to the LRGV to reduce impedance and increase power flow
  - When IBR's become "radial" into series capacitors (through outages), it can create negative interactions that impact the resources and the grid

AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY℠

RGV/South Texas Challenges

- Multiple Generic Transmission Constraints – GTC's
  - GTC's are a set of grouped transmission elements defined to limit flows between geographic regions
  - GTC's are defined due to an inability to directly observe and monitor the constraints in real-time (stability-related)
  - GTC limits are more constraining than the sum of the thermal ratings of the associated transmission elements
  - GTC limits can impact both service to load and delivery of generation
  - 7 of 16 ERCOT GTC's in RGV
  - GTC's overlap (GTC within a GTC) and are becoming difficult to manage and study accurately
  - Considered economic constraints with conditional exit plans
  - Issues/constraints are expanding to the entire South Texas region

- Difficulties/Delays associated with permitting and siting new transmission infrastructure
  - Residential and commercial growth congesting some areas
  - Numerous commissions and agencies to work with (IBWC, USFWS, TPWD, US Border Control, etc.) as well as County and City Governments
  - Numerous irrigation, water canals, pipelines, wells, etc.
  - Potential conflicts with other infrastructure improvements that are planned to meet growth

- Aging infrastructure
  - Flexible AC Transmission System (FACTS) devices, primarily dynamic reactive power devices
  - Old wood pole transmission lines

SM

AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY℠

Takeaways

- Majority of LRGV generation is intermittent (wind) with output subject to environmental conditions
  - Two (2) combined cycle plants comprise the majority of conventional capacity
- Import capability can vary significantly and is dependent upon resource reactive capability (see previous bullet)
  - Can experience reduced generation output and reduced import capability at the same time due to the correlation
- LRGV load (existing) is highly volatile particularly in winter
- Due to limited integration with the larger ERCOT network the "margin for error" is less while the uncertainty in generation, load and import capability is more
  - The impact of forced outages (generation or transmission) can have proportionally higher impact on the LRGV

Takeaways

- Last major 345kV transmission path to the LRGV was placed into service in 2015 along with energized reconductors of the two (2) existing 345 lines.
  - Upgrades followed major load shed event triggered by cold temps
  - Lack of sufficient redundancy required energized reconductors
- The time required for approval, siting and construction of new transmission facilities can be six (6) years or longer
- The last AEP Regional Planning Group (RPG) submission indicated approximately 200MW of "headroom" in LRGV load serving capability based on Planning studies
  - Multiple spot load additions well in excess of the available capacity have expressed interest in locating in the RGV (also the Coastal Bend Area)
  - These loads typically request service in 18-24 months
  - Recent ERCOT studies indicate more headroom due to additional generation (intermittent)
- Valley has 4% of the load (LRGV) and 44% of the GTC's (RGV)

Recommendations

- Take a more proactive approach to Planning the system in the RGV
  - Previous experience indicates "just-in time" or "not-in-time" Planning
  - Current studies utilize power flow models that represent 6 years out, while the approval and construction process can be 6 years or more
  - Consider impact associated with retirement of series caps and conventional generation
- Expand input assumptions utilized in Planning studies and adjust to reflect RGV realities
  - Load, generation and outages
- Consider implementation of N-1-1 criteria to increase redundancy and more closely align Planning with Operations
- Address the proliferation of GTC's through recognition of reliability impacts and/or adjustments to the economic criteria (SB1281)
- Build more transmission to more tightly integrate the RGV to the rest of ERCOT, resolve intra-Valley constraints and increase available headroom for load serving capability

AMERICAN ELECTRIC POWER

BOUNDLESS ENERGY℠

Appendix

Historical Review of RGV Events

- 1994 PTI extended term voltage stability analysis
  - Added shunt cap banks
  - 1996 UVLS to avoid voltage collapse for N-2
- 1995 Joint study with MVEC and PUB
  - Led to IRP filing in 1997 and subsequent Valley RFP
- 1997 EPRI study of FACTS devices to maximize import capability
  - Installed series compensation on both 345kV lines
  - Added Statcoms at Military Highway and Laredo
  - Established timing for RFP resource in service dates (2001)
- 1998 Multiple forced outages resulted in 350MW UVLS
- 1999 Valley RFP's issued
  - Supply Side, Demand Side, Transmission and Renewables RFP's
    - New Lobo to North Ed 345kV line submitted in response to Transmission RFP
  - Market and Regulatory landscape changing rapidly
  - Market mechanisms incented new generation development in the LRGV (early 2000's)
    - Three new merchant combined cycle plants constructed
  - RFP's cancelled as new generation development occurred regardless of RFP

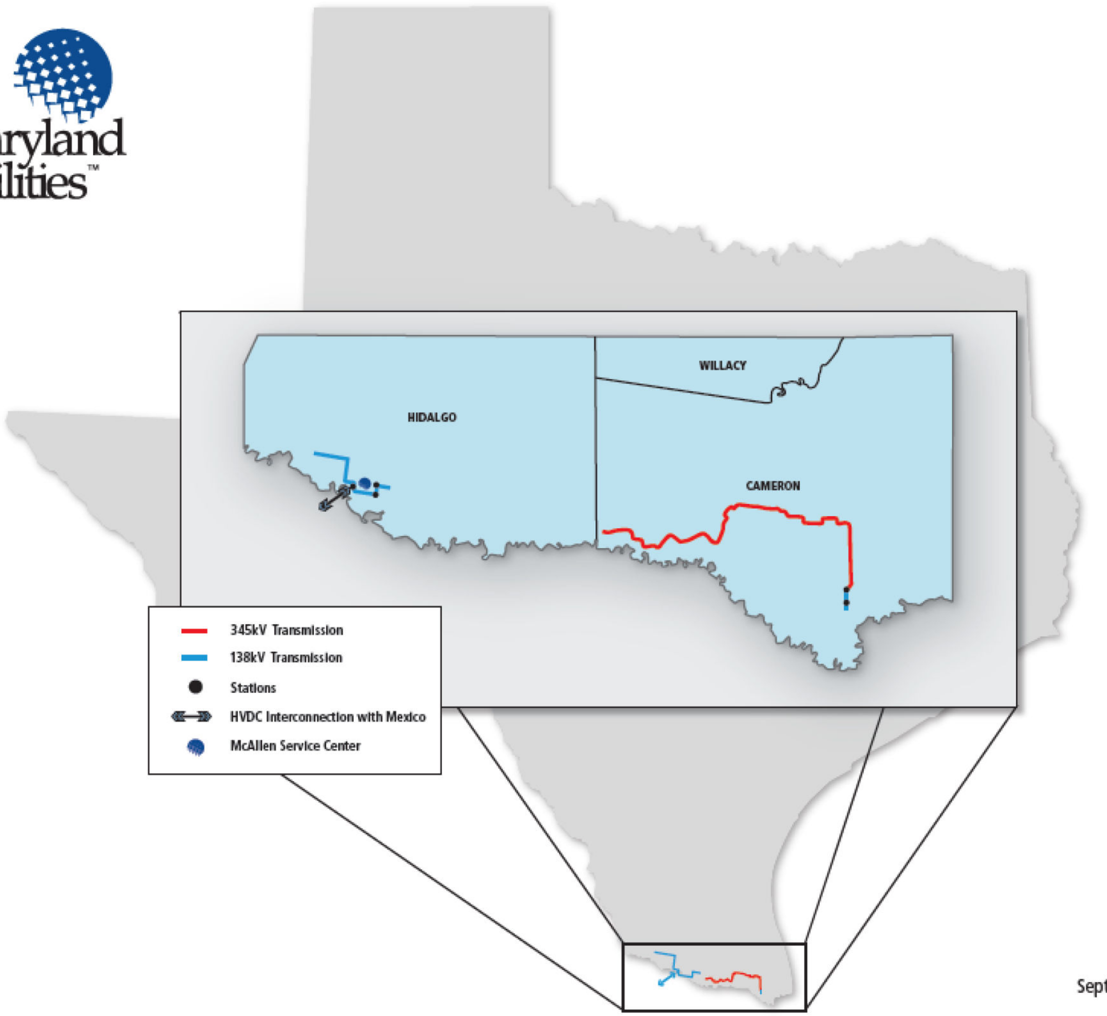
AMERICAN ELECTRIC POWER

BOUNDLESS ENERGY℠

Historical Review of RGV Events

- 2001 – 2004 Various 138kV and 69kV improvements within the Valley
  - Reconductored 138kV lines between North Edinburg and South McAllen with high temp conductor
  - 69kV to 138kV conversions
  - 2004 RPG filing recommended new 345kV from North Ed to Frontera based on 138kV loading triggers
  - Improvements were made to remove Bates and LaPalma as must run; both plants later were shut down
- 2011 Cold temps resulted in significant load increase
  - 300MW manual load shed to avoid voltage collapse
- 2011 RPG filing for new Lobo to North Ed 345kV line
  - ERCOT endorsed new 345kV line plus reconductor (energized) of the two existing 345kV lines (late 2011)
- 2015 New Lobo to North Ed 345kV and both 345kV reconductors in-service
- 2015 RPG filing for additional dynamic reactive and 4th 345kV source to the LRGV (Frontera leaving ERCOT)
  - ERCOT endorsed additional reactive but no new line
- 2016 Frontera switched to Mexico; ERCOT endorsed Stewart Road 345kV Cut-In
- 2017 RPG filing for additional reactive/138kV upgrades with 4th 345kV to the Valley based on sensitivity
  - ERCOT recommended new 345kV but contingent upon signed load agreements
  - Working on studies now for new Del Sol – Frontera 345kV (in lieu of reactive)

Sharyland is a Transmission Service Provider Operating Facilities in the Lower Rio Grande Valley



September 2020

Lower Rio Grande Valley Transmission Challenges: Recap of Facts

- The Lower Rio Grande Valley is a winter peaking area
- Significant portion of generation in the region is inverter-based
- Large loads can quickly materialize in the region with minimal excess capacity to serve
- Region can operate as a load pocket or generation pocket, relying on imports <u>and</u> exports of generation
- High number of Generic Transmission Constraints (GTCs) in LRGV region
- ERCOT's 60-point "Roadmap to Improving Grid Reliability" specifically identifies the LRGV as an area in ERCOT that needs new transmission capacity to increase market access for resources and improve reliability for customers during both normal conditions and high-risk winter events
- Over the past 10 years, several transmission projects have been proposed to address the Rio Grande Valley Import GTC but have not been approved; ERCOT is considering adjusting its reliability analysis to take into account more extreme weather events and potentially other factors

Sharyland Utilities™

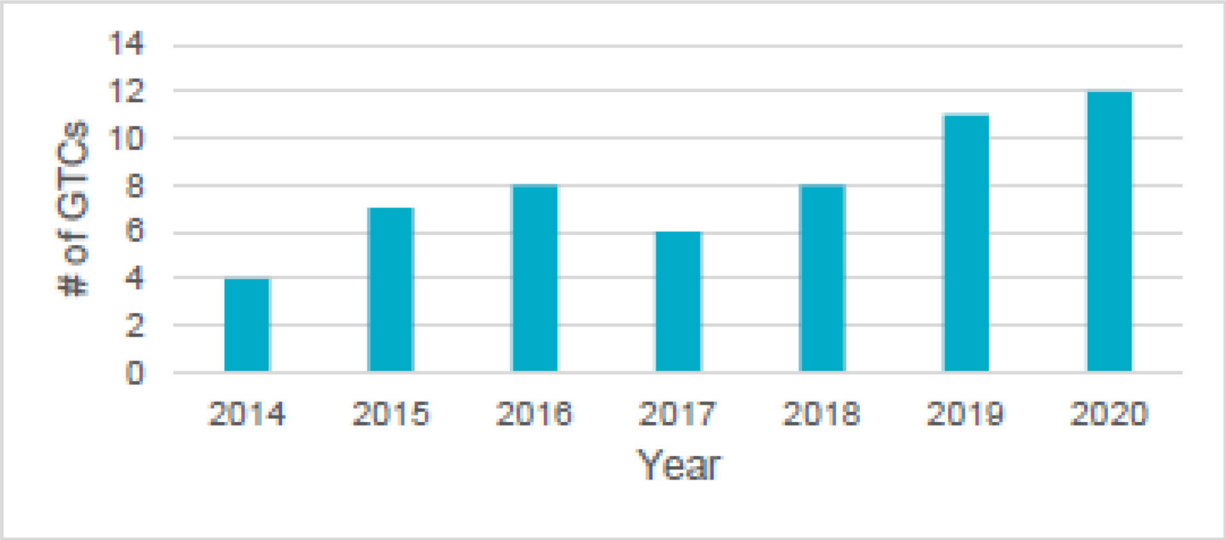
Transmission Planning

- The transmission planning process includes two methods for reviewing proposed transmission projects
  - Reliability Test
    - Considers whether a proposed transmission project is needed to meet the reliability criteria required by the North American Electric Reliability Corporation (NERC) and ERCOT
  - Economic Test
    - Historically, if a proposed transmission project fails the reliability test, then ERCOT can evaluate the project as an "economic project." To analyze whether a project is "economic," ERCOT determines whether it is economic to build new transmission to relieve transmission constraints and allow lower-cost generation to flow more freely to customers
    - Transmission projects proposed under the economic test eventually may be justified as reliability projects but do not pass the reliability test when first proposed because of time horizon used for the reliability test
    - Transmission projects that meet the economic test can:
      - Address intra-Valley congestion (thereby lowering cost to consumers); and/or
      - Address certain GTCs that prevent generation from being exported from the Valley (note that ERCOT's Technical Advisory Committee intends to study how much generation was curtailed behind export GTCs during Winter Storm Uri)

Sharyland Utilities™

SB 1281 Addresses the Transmission Planning Economic Test

- SB 1281 requires estimated congestion cost savings for consumers to be considered when the economic test is applied
- The Commission's "87th Regular Legislative Session Implementation Schedule" shows the rulemaking to implement SB 1281 as concluding in June of 2022 and ERCOT's implementation will follow decisions made in that rule
- Meanwhile, transmission issues in the Valley are increasing rapidly



Source: Use of Generic Transmission Constraints in ERCOT, July 2020 Report

Sharyland Utilities

Recommendations

- To quickly and meaningfully address the transmission constraints in the Valley that have existed for more than a decade, ERCOT should use all tools at its disposal, including evaluating projects under both the reliability test and the economic test

- **Economic Test:**
  - Because economic projects are often early solutions to long-term reliability issues, failing to review those projects while the SB1281 rulemaking is pending will unnecessarily delay these projects
  - SB1281 is clear that the economic test for transmission projects "must include a comparison of the estimated cost of the transmission project for consumers and the estimated congestion cost savings for consumers that may result from the transmission project." ERCOT is well-equipped to apply this statutory language to proposed transmission projects on a case-by-case basis, and should be authorized by the Commission to do so

- **Reliability Test:**
  - When comparing proposed projects under the reliability test, consider utilizing a broader analysis that takes into account additional benefits, including congestion cost savings, completion time, and overall costs

Sharyland Utilities™