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Reliability analysis and resource adequacy --
Best practices & recommendations

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The big picture:

We can’t modify the electric market to improve reliability without a detailed understanding of current and forward-looking reliability needs

Six resource adequacy principles for ERCOT

1) Load participation (demand-side DR, EE, DERs) fundamentally changes the resource adequacy construct.
2) Modeling chronological operations across many weather years is essential.
3) Quantifying size, frequency and duration of capacity shortfalls is critical to finding the right resource solutions.
4) There is no such thing as perfect capacity. All resources have limitations based on weather, outages, flexibility constraints, and common points of failure. And a mix of supply and demand resources complement each other, so evaluate portfolios rather than individual resources.
5) Reliability criteria should not be arbitrary, but transparent and economic.
6) Incentives must be aligned with system need and customers' needs.

Based on Derek Stenclik, "Five Principles of Resource Adequacy for Modern Power Systems" and reader comments (retrieved 11/17/21), and ESIG, "Redefining Resource Adequacy for Modern Power Systems" (August 2021).

On ELCC, see GridWorks, "Resource Adequacy – Reliability through the Clean Energy Transition," (March 2021) and E3, "Capacity and Reliability Planning in the Era of Decarbonization – Practical Application of Effective Load Carrying Capacity in Resource Adequacy" (August 2020)

Reliability and resilience analysis

- Historically, resource adequacy was about having enough capacity to serve peak load. But today, periods of risk and reliability events occur not only at peak load, but also during shoulder months and in net peak hours (energy &fuel adequacy as well as resource adequacy) -- all intervals matter.
- Global conditions and threats have moved beyond the bounds of historical events and evidence. Therefore load forecasting, reliability, and resilience analysis must consider:
  - Conditions previously unimaginable (e.g., Oregon 2021 heat wave, Hurricane Harvey flooding, California wildfires) and more frequent occurrences of high impact extreme weather events
  - How load reacts to temperature
  - The potential for compound asset failures (e.g., loss of fuel supply) from common failure modes
  - Transmission is an asset as well as an enabler of generation & storage assets
- Reliability and resilience are characteristics of a system and portfolio of resources, not of individual assets.

Reliability analysis

In a high-renewables system, we need to "characterize the size, frequency, duration and timing" of capacity shortfalls and reliability events to identify appropriate reliability solutions. This analysis should reflect detailed time granularity (at least 15 minutes or shorter shortfall durations across all hours and seasons) and detailed geographic granularity (e.g., reflecting new generation resource locations and transmission constraints) in order to characterize ancillary service product needs.

Probability distribution of power and energy shortfalls for sample power system

Larger Power Shortfalls (MW) →

Larger Energy Shortfalls (MWh) ↓

Energy (MWh)	Max Size (MW) 10	20	30	40	50	60	70	80	90	100	110	120	130	140	150	160	170	180	190	>=200	Total
20	19.9%	14.4%	5.31%																		39.6%
40		0.70%	6.02%	6.11%	1.41%																14.2%
60			0.61%	2.34%	3.90%	1.60%	0.26%														8.7%
80			0.03%	0.58%	1.89%	2.18%	1.41%	0.16%													6.2%
100			0.03%	0.06%	0.64%	1.63%	1.66%	0.90%	0.06%	0.13%	0.06%										5.2%
120					0.06%	0.42%	1.12%	1.47%	0.67%	0.16%	0.10%	0.03%									4.0%
140							0.51%	1.02%	0.74%	0.35%	0.06%										2.7%
160						0.06%	0.32%	0.80%	0.42%	0.48%	0.19%	0.03%	0.03%								2.3%
180					0.03%		0.10%	0.35%	0.38%	0.42%	0.32%	0.06%	0.06%								1.7%
200							0.10%	0.29%	0.42%	0.51%	0.42%	0.32%	0.06%	0.03%	0.03%						2.2%
220						0.03%		0.06%	0.42%	0.16%	0.35%	0.26%	0.10%	0.03%							1.4%
240								0.06%	0.10%	0.16%	0.16%	0.29%	0.19%								1.0%
260								0.06%	0.03%	0.19%	0.35%	0.16%	0.29%	0.10%	0.19%		0.03%				1.4%
280							0.03%	0.03%	0.03%	0.03%	0.19%	0.19%	0.22%	0.10%	0.19%		0.03%				1.1%
300								0.03%		0.03%	0.16%	0.13%	0.13%	0.10%	0.03%						0.6%
320										0.10%	0.06%	0.06%	0.22%	0.10%	0.16%			0.03%			0.7%
340											0.03%	0.03%	0.16%	0.06%	0.16%	0.03%					0.5%
360											0.03%	0.10%	0.19%	0.06%	0.29%	0.03%	0.06%				0.8%
380												0.06%	0.03%	0.06%	0.13%	0.13%	0.16%				0.6%
400												0.06%	0.03%	0.16%		0.10%	0.06%	0.06%			0.5%
>400											0.16%	0.10%	0.22%	0.16%	0.35%	0.74%	0.32%	0.51%	0.42%	1.60%	4.6%
Total	19.9%	15.1%	12.0%	9.1%	7.9%	5.9%	5.5%	5.2%	3.3%	2.7%	2.7%	1.9%	2.0%	1.0%	1.5%	1.0%	0.7%	0.6%	0.4%	1.6%	100%

70% of events covered by 60 MW 2HR resource

85% of events covered by 100 MW 2HR resource

Source: Stenclik, "Redefining Resource Adequacy for Modern Power Systems," (11/16/21)

How to analyze future reliability needs

Forward-looking reliability analysis must be modeled using:

- Probable resources from the interconnection queue, DERs and demand-side programs
- Chronological operations, scheduling and location, to reflect both solar and wind variability and energy storage and demand response recharging and duration.
- Scenario analysis that considers extreme conditions (forward-looking extreme weather events capturing rising frequency, duration, geographic scope and duration of events) and risks as well as multiple future supply portfolios and demand levels and configurations.
- Use multiple years of historic weather to estimate wind and solar production capabilities and duration of low and high wind and solar production and ramp requirements (but not necessarily historical probabilities).
- Monte Carlo analysis that combines many (100s to 1,000s) combinations of portfolios and risks to identify performance, problems and costs of each combination.
- Do NOT aggregate using averages, but look at ranges and frequency distributions of the Monte Carlo simulation outcomes.

Sources & resources

See NERC, "Probabilistic Fundamentals & Models in Generation and Bulk Power Reliability Evaluation" (2017) and ESIG, "Redefining Resource Adequacy for Modern Power Systems" (2021)

Examples – see Draft 2021 Northwest Power Plan and planning process, "PJM's Evolving Resource Mix and System Reliability" (2017), and "Fuel Security Analysis: A PJM Resilience Initiative" (2018)

Resource adequacy metrics

ERCOT currently looks at Planning Reserve Margin and Economically Optimal Reserve Margin (see e.g., Astrape Study for ERCOT) but doesn't use a specific reliability standard.

Common reliability metrics (see next slide) reveal different facets of the same events, to reveal the depth, duration and economic costs of customer impacts

- Planning reserve margin
- LOLE (Loss of Load Expectation)
- LOLH (Loss of Load Hours)
- EUE (Expected Unserved Energy)
- LOLEv (Loss of Load Events)

No one metric is sufficient

Event Characteristic	Metric Affected	California Aug 2020	Texas Feb 2021	Delta
Number of Days	LOLE	2 days	4 days	+200%
Number of Events	LOLEv	2 events	1 event	-50%
Number of Hours	LOLH	6 hours	71 hours	+1200%
Unserved Energy	EUE	2,700 MWh	990,000 MWh	+36,700%
Max Shortfall		1,072 MW	20,000+ MW	+1,766%

Source: Stenclik, , "Redefining Resource Adequacy for Modern Power Systems," (11/16/21)

Resource Adequacy metrics details

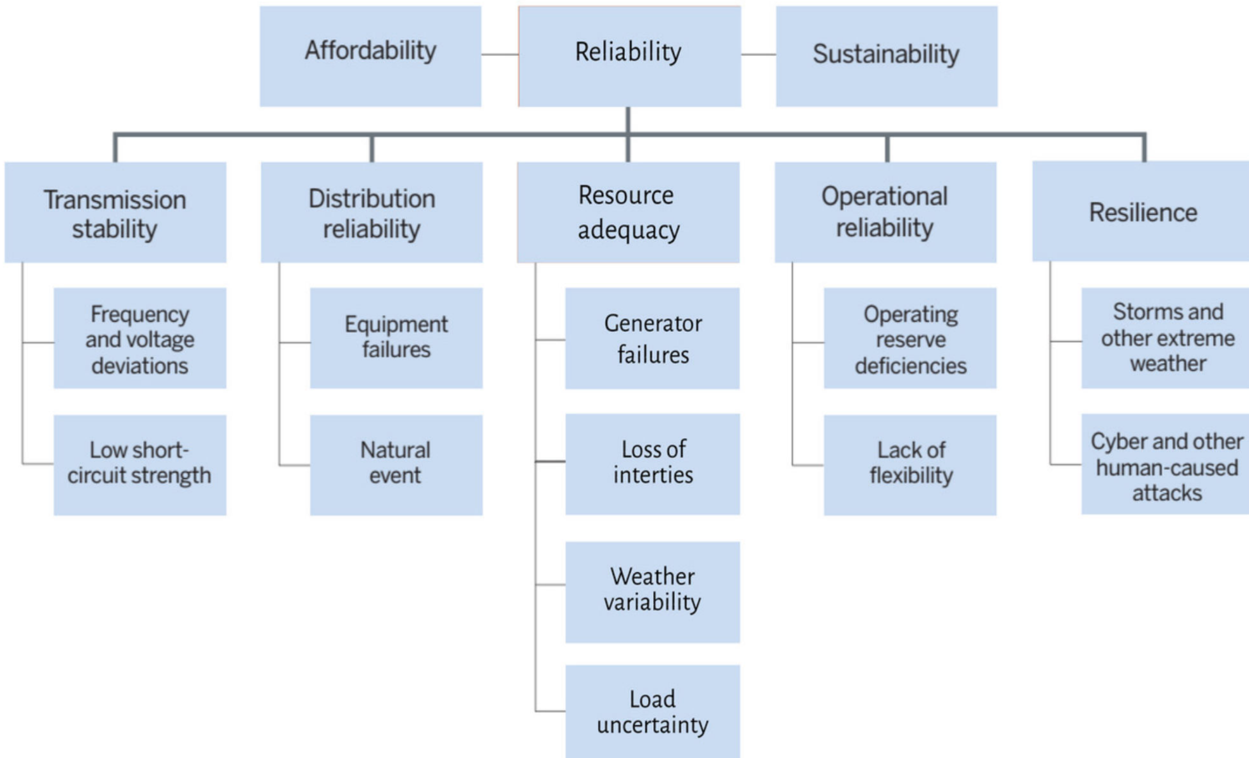
Refresher on Existing RA Metrics

Metric	Description	Limitations
Loss of Load Expectation (LOLE) days/year	Counts the number of loss of load **days** across all the random samples simulated. The total number of days with a shortfall is then divided by the number of samples to give an average days per year with a shortfall.	Quantifies the frequency of shortfalls, but does not provide information of size, duration or timing.
Loss of Load Events (LOLEv) events/year	Counts the number of loss of load **events** each year. Where an event is characterized as consecutive hours of a shortfall. Where one day may have multiple events, or one event may span multiple days.	Evaluates shortfall events based on consecutive duration, but does not provide information of size, duration or timing.
Loss of Load Hours (LOLH) hours/year	Counts the number of loss of load **hours** across all of the random samples simulated. The total number of hours with a shortfall is then divided by the number of samples to give an average hours per year with a shortfall.	Provides some insight into duration when combined with LOLE (LOLH/LOLE = hours/day) but does not provide insight into size of events.
Loss of Load Probability (LOLP) % of Days	Calculates a **probability** of a shortfall loss of load event occurring, between 0 and 1, often calculated as the number of days with a shortfall, divided by the total number of days sampled.	Similar to LOLE.
Expected Unserved Energy (EUE) MWh/year	Calculated the average amount of unserved **energy**, in MWh, in a given year. Unserved energy can be calculated as either the number of operating reserves not provided, or involuntary curtailed load.	Quantifies the size (magnitude) of loss of load, but does not provide information on the frequency or duration of the events.
Normalized Expected Unserved Energy (NEUE) % of load/year	Provides the same information as expected unserved energy but reports shortfalls as a percentage of system load as opposed to MWh to provide a relative risk level across different systems or load years.	Similar to EUE.

From Derek Stenclik, "Beyond 1-day-in-10 – Four Recommendations for Improved Use of Resource Adequacy Metrics,"(10/7/21)

Supplemental information

Elements of grid reliability



Source: ESIG, "Redefining Resource Adequacy for Modern Power Systems" (August 2021)

EPRI recommendations & observations

from "Exploring the Impacts of Extreme Events, Natural Gas Fuel and Other Contingencies on Resource Adequacy" (1/28/21)

The electric industry systematically understates the probability and depth of many high impact common mode events. Extreme weather events are rising in frequency, intensity, geographic scope, and duration; the impact of weather is non-linear and rising much faster than frequency.

Due to the rising trend in disruptive events and common mode outages, the traditional approaches to ensure resource adequacy need to evolve:

- To project disruptive event probabilities moving forward, the historical probabilities for the frequency, intensity, geographic scope, and duration of weather events need to be adjusted upwards to take recent climate trends into account. Probabilistic weather forecasts are another tool that can help deal with rising frequency, intensity, and duration of extreme weather events.
- The resource adequacy framework needs to be modified to reflect the depth, duration, and economic costs of unserved energy, and supplemented to account for common mode events. Scenario planning for high impact common mode outages should be included in resource planning. Such planning should include scenarios that are relevant to the specific region, and consider both investments and potential operational responses.
- The interaction between the natural gas and electric power markets needs to be restructured to remove the operational inefficiency that exists today due to the nonalignment of the daily and longer market cycles of the two industries.
- Planning in the power industry needs to evolve to acknowledge the stochastic realities brought about by variable resources, increased variability in weather, and changing consumer behavior. These changes can be addressed by the development of probabilistic metrics and analytic / modeling systems that can measure, probabilistically, the economic impacts of these changes beginning with the development of scenario planning methods of extreme events.

The authors' key recommendations are to:

- Develop scenarios by region of high impact, common mode events, and estimate the probability distributions of the scenario's physical impacts and associated economic costs.
- Develop regional Value of Loss Load (VOLL) studies that update and extend the available estimates of customer outage costs.
- Develop a modeling framework to combine an operational model of the natural gas pipeline network with a production costing power system model.
- Develop a disruptive weather classification system including intensity, geographic coverage, and duration directly targeted for use by the US Electricity Market.
- Develop Value of Load at Risk as a conceptual framework to address the shortcomings of the current resource adequacy metrics.
- Develop a stochastic mathematical programming model for resource planning and pricing resource scarcity.

NERC on reliability planning

From State of Reliability Report, 2021

The risk of resource shortfalls is no longer restricted to the summer peak demand periods and must now be anticipated during shoulder months or even winter.

The ERO and industry should continue improving their ability to model, plan, and operate a system with a significantly different resource mix. Priority should be given to understanding the implications of the following:

- Frequency response under low inertia conditions
- Contributions of inverter-based resources to essential reliability services
- Increasing protection system and restoration complexities with increased inverter-based resources
- With the transformation of the resource mix towards one that can exhibit energy limitations during wide-spread, long-duration extreme events, application of energy planning approaches, including expected unserved energy metrics should be used alongside traditional capacity planning approaches that highlight the implications of the planned resource mix on the sufficiency of energy. Application of energy metrics can lead to a resource mix that can be more resilient to widespread, long-duration extreme events.
- System planners should evaluate the need for flexibility as conventional generation retirements are considered by industry and policymakers. Retirement planning studies should consider Interconnection-level impacts and sensitivity assessments associated with the loss of critical transmission paths and the loss of local generation in larger load pockets.
- The ERO and industry should develop comparative measurements and metrics to understand the different dimensions of resilience (e.g., withstanding the direct impact, managing through the event, recovering from the events, preparing for the next event) during the most extreme events and how system performance varies with changing conditions.

From "2021 ERO Reliability Risk Priorities Report" (August 2021)

The traditional methods of assessing resource adequacy (i.e., by focusing primarily on generating capacity, transmission and pipeline capacity, and fuel availability at traditional peak load times) may not accurately or fully reflect the ability of the new resource mix to supply energy and reserves for all operating conditions. Historic methods of assessing and allocating ancillary services (e.g., regulation, ramping, frequency response, voltage support during transient, recovery, follow through) may no longer ensure that sufficient essential reliability services and contingency reserves are available at all times during real time, next hour, and next day operations. Balancing and ramping concerns that up to now have been largely confined to limited locations will likely expand regionally as solar and wind generation continues to grow and provides a larger portion of the energy mix. Changes in resources will increasingly challenge concepts of available capacity in traditional integrated resource planning models and methods; this will likely lead to a need to revise resource adequacy, energy adequacy, and transmission adequacy concepts to assure reliability of the BPS in near-term to long-term planning horizons.

Ensure sufficient operating flexibility at all stages of resource and grid transformation: System operators and planners should ensure that sufficiently flexible ramping/balancing capacity is available as a tool to meet the needs of changing patterns of variability and new characteristics of system performance. Traditional concepts of resource adequacy may need to evolve to consider adequacy and flexibility during all hours, including consideration of correlated outages, transmission availability, and common-mode fuel supply dependencies.

Energy efficiency for ERCOT reliability

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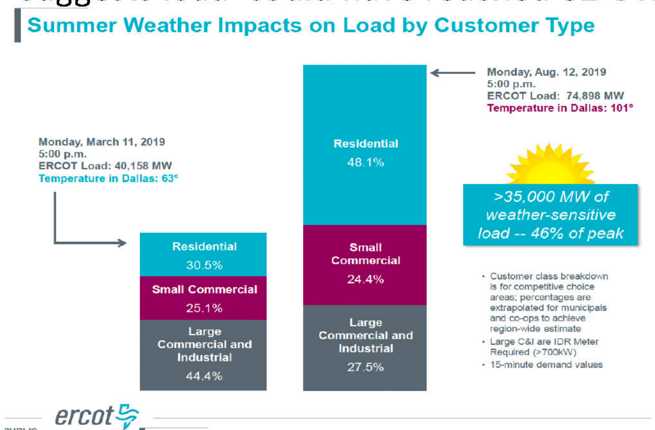
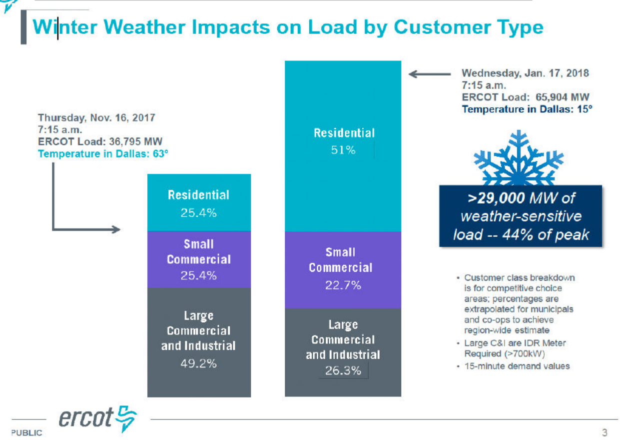
The big picture:

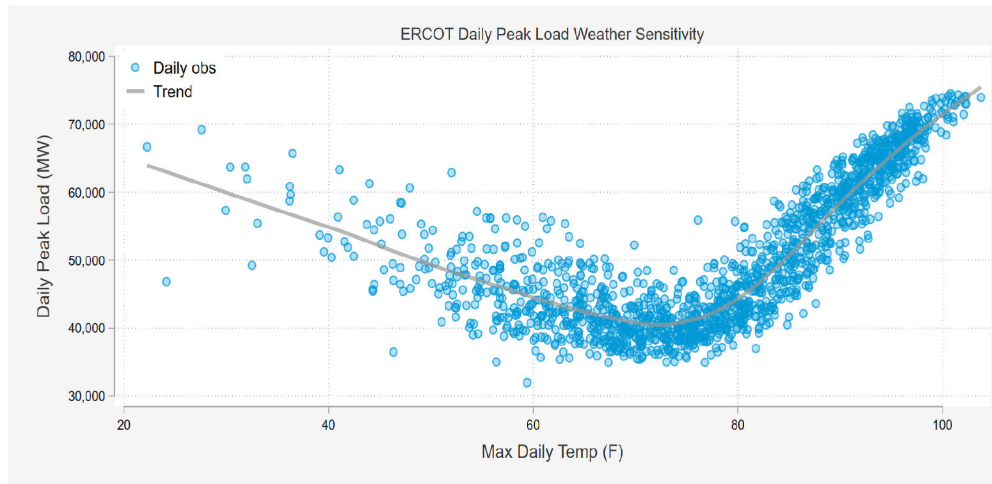
Resource adequacy and reliability require meeting demand with adequate supply – which means managing demand as well as supply. The Commission and ERCOT need to use energy efficiency and demand response more effectively for grid reliability and affordability.

Why residential EE & DR? ERCOT peaks dominated by weather-sensitive loads

ERCOT estimates that w/o Uri load-shed, customer load would have peaked at 76.8 GW on 2/15/21; another estimate suggests load could have reached 82 GW (22% over ERCOT forecast) but for the load-shed.







Resources and sources

- Alipour et al, "Assessing climate sensitivity of peak electricity load for resilient power systems planning and operation: A study applied to the Texas region" (July 2019)
- Davis, "Can Energy Efficiency Help Avoid Blackouts?" *Energy Institute Blog*, UC Berkeley (5/24/21)
- Josh Bode, Demand Side Analytics, ERCOT 2017-2021 load data
- Lee & Dessler, "The Impact of Neglecting Climate Change and Variability on ERCOT's Forecasts of Electricity Demand in Texas" (9/16/21)

Texas keeps growing, and so will electric peak demand

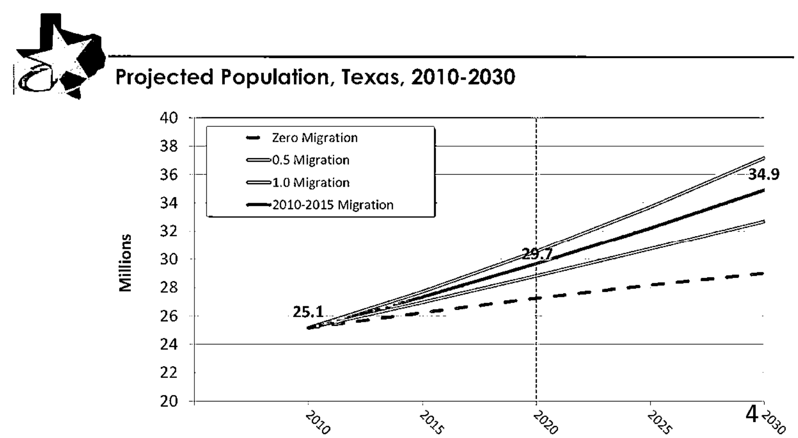
Relentless load growth:

- ERCOT peak demand grew 6.4% between 2015-2020
- ERCOT energy use grew by 10% between 2015-2020
- TX population growth up 16.8% (4.2 million people added, to reach 29+ million people) 2010-2020, adding 1.5 million new housing units
- Projected Texas population up to 34.9 million by 2030

We can't build our way out of this growth challenge using only electric generation & trtansmission without imposing major costs on consumers.

Sources & resources

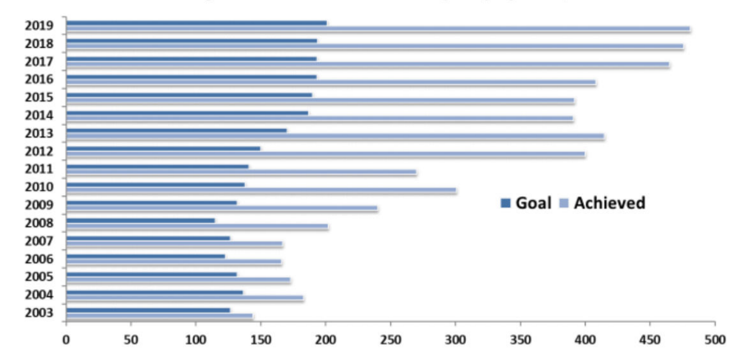
- "Demographic Trends and Population Projections for Texas and the North Texas Region", Texas Demographic Center (1/15/21)
- Davis, "The Texas Power Crisis, New Home Construction, and Electric Heating" *Energy Institute Blog,* UC Berkeley, (2/22/21)

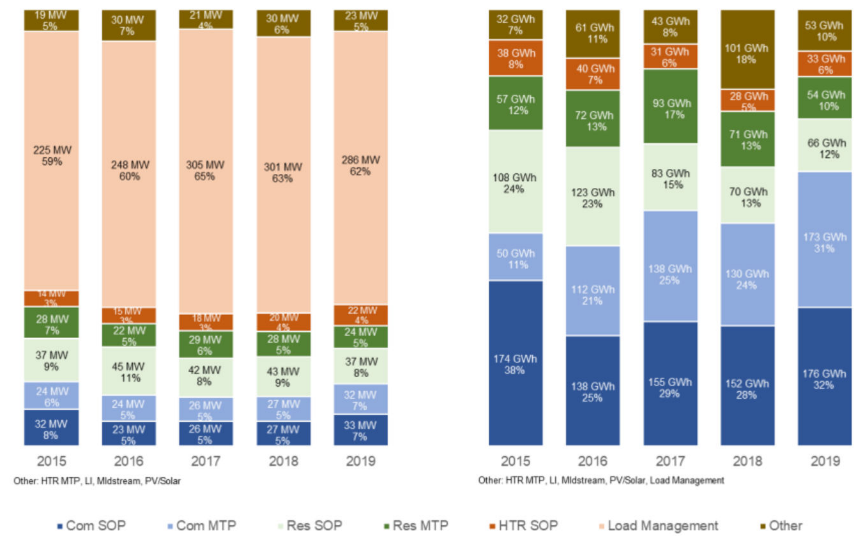


Texas TDUs have been making EE and DR work

- In 2019, the Texas IOUs have delivered 654 GWh of energy savings and 480 MW of peak demand reduction goals under the PUC's EERS program, for a cost of $126 million.
- The Texas EERS has been designed to achieve summer peak reductions and energy savings.
- Over 60% of the demand reduction savings came from commercial and load management programs rather than from residential programs.
- Texas TDU EE-DR programs delivered demand reductions at a lifetime savings cost of $16.94/kW and energy savings at a lifetime cost of $0.01/kWh.
- All TDU EE-DR portfolios have benefit-cost ratios >= 2.2

Figure 1. Demand Reduction (MW) by IOUs, 2003-2019





Sources & Resources

- EUMMOT, "[Energy Efficiency Accomplishments of Texas Investor-Owned Utilities, Calendar Year 2019]"
- Public Utility Commission of Texas, "[Volume 1. Statewide Energy Efficiency Portfolio Report Program Year 2019]" Tetra Tech (7/30/30)

But residential EE and DR are under-utilized resources

- There are 11.3 million homes in Texas (as of 2019), most of which were built before Texas adopted minimum energy efficiency building standards
  - 3.8 million, or 41% are low-income households with an average energy burden of 10%
  - About 2/3 of all Texas housing units are single-family homes and 1/3 are multi-family homes or manufactured homes
- Since the TDU EE-DR programs reach 0.4% of annual kWh sales, few homes in Texas have been touched by formal energy efficiency programs (even after 20 years)
  - TDU EERS – no clear data found on number of households served
  - Federal weatherization funds – TDHCA reports in its latest report that a total of 2,916 low-income households received weatherization using DOE and LIHEAP WAP funds in 2018.
- Other states use utility EE targets of 0.7% up to 3% of electricity sales or incremental electricity savings each year, so TX's EERS goal is far below the 1.2% average.
- The proposed ACEEE EE-DR program aims to reach 9.8 million Texas households in 6 years

Sources and resources

- Texas Energy Poverty Research Institute, "Low Income Community Profile Series, Part 1. Texas Overview" (June 2019)
- U.S. Census Bureau, Quick Facts Texas
- Texas A&M University Texas Real Estate Research Center, "Tracking Texas Housing Trends" (9/6/19)
- ACEEE, "The 2020 State Energy Efficiency Scorecard," (December 2020)

Making residential EE and DR work for Texas
-- Action plan and rationale

ERCOT Stakeholder Group EE & DR action plan

1) Start implementation of ACEEE EE-DR recommended measures immediately to begin moderating growth of electric load
2) Reform Texas' energy efficiency resource standard (EERS) and increase goal to at least 1% of retail sales annually. Let utilities trade savings credits
   - Target both summer and winter peak reductions
   - Increase energy efficiency cost recovery factors to support utility efforts
   - Increase program budget allocations for low-income households to 20%
3) Set LSE demand response goals to acquire residential DR at 10% of peak load by 2027
4) Set market rules for compensation and aggregation to better enable residential demand response
5) Commission EE & DR potential study to determine how much more peak reduction and energy savings are technically and economically feasible and determine best programs to achieve fast peak reductions and reliability impacts; modify TDU EE-DR program later based on study results.

Which EE and DR?

Invest in EE and DR targeted specifically to reduce summer and winter peak loads, not just traditional EE to reduce kWh usage

- More EE enables homes and buildings to offer more DR
- ACEEE-recommended EE and DR measures

Energy efficiency programs

- Electric furnace replacement program (with Energy Star heat pumps)
- Attic insulation and duct sealing incentive program
- Smart thermostat incentive program
- Heat pump water heaters incentive program

PLUS, analyzed expected savings from federal incandescent lighting phaseout – FREE SAVINGS!

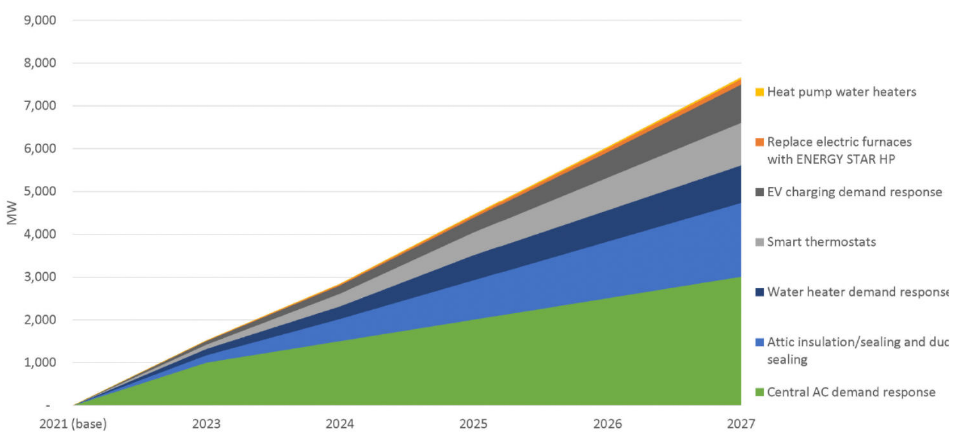
Demand response programs

- Central air conditioner demand response program (with smart thermostat control)
- Electric vehicle managed charging program
- Water heater demand response program

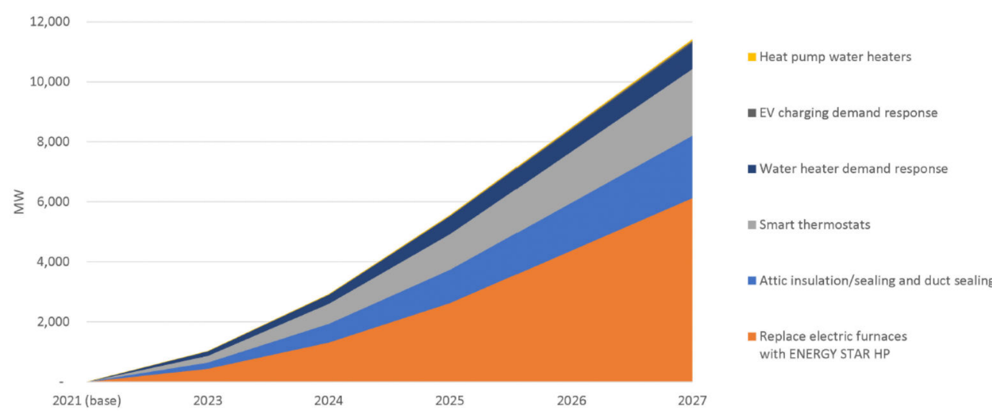
EE-DR can be increased quickly

Potential peak-reducing impacts of ACEEE-recommended EE-DR measures
Planning & implementation in 2022, full delivery 2023-2027

Summer peak load reductions: 7,650 MW



Winter peak load reductions: 11,400



- Around-the-clock energy savings that reduce net peak load gap and create automated dispatchable demand flexibility.
- Cost of saved energy = $0.056/kWh – way cheaper than new gas generation resources
- Lowers customer bills, improves customer health, raises property values
- Creates customer and community resilience against future outages

Reasons for more energy efficiency and demand response

- EE & DR recommended by FERC-NERC Winter Storm Uri Investigation Report
- EE & DR effectively reduce peak load and thereby stretch supply reserves further
- EE & DR can be increased quickly
- EE & DR are more cost-effective than most other resources
- DR can provide a variety of dispatchable grid flexibility and ancillary services
- EE & DR improve reliability, reduce risk from poor ERCOT forecasting and have low probability of failure compared to generation and transmission
- EE & DR lower total system cost and customer bills to buffer against supply-side cost increases
- Residential EE and DR resource is under-utilized
- Wasting energy does not benefit customers or the Texas economy

EE-DR recommended by FERC-NERC Winter Storm Uri Investigation Report

- Key Recommendation 16: “Balancing Authorities should have staff with specialized knowledge of how weather impacts load, including the effects of heat pump backup heating and other supplemental electric heating. ... Electric heat pumps provide a significant portion of the residential heating load in the southern U.S. Heat pumps have a rated outdoor operating temperature, which is the minimum temperature at which the unit will efficiently operate. As temperatures drop, the heat pump is able to extract less heat from the ambient air, requiring more electricity to generate the quantity of heat (BTUs) it would at warmer temperatures. During severe cold weather, heat pumps become ineffective and those homes must rely on auxiliary (aux.) electric resistance heating instead.” (p. 224)
- Key Recommendation 18: “… public utility commissions should consider providing incentives for additional demand-side management resources that could be deployed in a short period of time (i.e., 30 minutes or less), especially to replace unplanned outages or derates of generating units, and where resources are most likely to be needed during times of short supply….” (p. 226)
- Key Recommendation 19: “State public service/utility commissions or legislatures should consider retail-level incentives for energy efficiency improvements. Such incentives could include energy efficiency audits and subsidizing energy efficiency measures with public funds. … One way to reduce load during extreme cold weather is to increase the ability of the housing stock to withstand the ambient temperatures through energy efficiency measures such as increased insulation, weather-stripping, energy-efficient windows and doors, etc.” (p. 227)

EE-DR enhance reliability and resource adequacy

- By lowering load and shifting the net load curve, EE and DR reduce the probability of load exceeding generation for those hours when generation availability is lower and load is relatively high -- as in peak hours, shoulder months when thermal plants take maintenance outages, and evening PV ramp-downs. This enhances reliability and resource adequacy, reduces the need for additional supply capacity and ancillary services, and slows the need for new and supplemental transmission and distribution facilities.
- EE and DR are reliable, predictable, long-term and measurable.
- EE and DR have low probability of failure compared to generation and transmission and reduce risk from poor ERCOT forecasting.
- Many aggregated DR programs, including smart thermostat controls and vehicle charging, can provide dispatchable, fast-ramping ancillary services.
- NREL finds that by lowering load, building energy efficiency investments can reduce the need for long-duration storage in high-renewables grids.
- The Northwest Power & Conservation Council's regional power and resource plans, aimed at "least cost with acceptable risk," consistently find that under a wide range of future conditions, EE supplemented by DR consistently proved to be the least expensive and least economically risky resource options to provide new peaking capacity.

Sources and resources

- Northwest Power & Conservation Council, Seventh Power Plan and draft 2021 Northwest Power Plan
- ACEEE, "Keeping the Lights on: Energy Efficiency and Electric Reliability" (October 2018) and "Demand-side Solutions to Winter Peaks and Constraints" (April 2021)
- Lawrence Berkeley National Lab, Frick et al., "Quantifying grid reliability and resilience impacts of energy efficiency: Examples and opportunities" (preprint November 2021), Frick et al., "Peak Demand Impacts from Energy Efficiency Programs" (November 2019)
- Houssainy & Livengood, "Optimal strategies for a cost-effective and reliable 100% renewable electric grid," Journal of Renewable & Sustainable Energy (11/21)

EE-DR are more cost-effective than competing resources

- Among EE programs now in effect across the U.S., about half of all program demand savings are available at a levelized cost of saving peak demand of < $100/kW, and three-quarters of all demand savings (including residential consumer programs) are available at < $200/kW. In contrast, Lazard estimates the capital cost of conventional new gas generation from $700 – 1,300/kW.
- All U.S. utility EE programs had a levelized program cost of saved energy of $0.024/kWh in 2018. ACEEE estimates that its recommended Texas EE programs would cost $0.056 /kWh of saved energy with a benefit/cost ratio of 2.7 for EE and 1.2 for DR measures. Current TX TDU EE-DR portfolios have a benefit-cost ratio >= 2.2.
- EE-DR lower total system cost and customer bills to buffer against supply-side cost increases. DOE-NREL estimated in 2017 that cost-effective residential energy efficiency measures could save 21% of the energy used in Texas single-family homes and create $2.7 billion per year in utility bill savings.

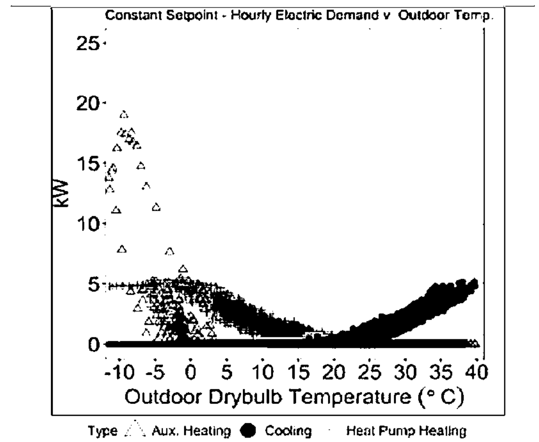
Sources & resources

- LBL, Frick et al., "Peak Demand Savings Opportunities and Practices" (12/23/20)
- ACEEE, "The Cost of Saving Electricity for the Largest U.S. Utilities: Ratepayer-funded Energy Efficiency Programs in 2018" (June 2021)
- EIA, Annual Energy Outlook 2021, "Cost and performance characteristics of new central station electricity generating technologies" (February 2021) – used for PUCT Project # 38578
- Lazard, "Lazard's Levelized Cost of Energy Analysis, Version 15.0" (October 2021)

Extra credit – resistance heating is bad news

From Mitsubishi Project 52373 comments and the FERC-NERC Uri Investigation report:

- The FERC-NERC February 2021 Cold Weather Outages in Texas… Report notes in Recommendation 16 that electric heat pumps operate less efficiently at temperatures below freezing, and require auxiliary heating [which is even less efficient, particularly in poorly insulated homes] at lower temperatures. (see diagram)
- Mitsubishi Electric Trane HVAC's comments in Project 52373 note that 61% of Texas homes use electric heating, much of which is inefficient resistance heating. Mitsubishi recommends converting existing residential electric heating to high efficiency (200 – 400% more efficient) inverter compressor heat pumps and incentivizing these also for new home construction, to reduce both winter and summer energy use at temperature extremes. ACEEE affirms this recommendation.
- Demand response programs are rarely able to manage baseboard heating, plug-in heaters, or window air conditioners.
- Recall AEP Texas engineers saying load volatility in the LRGV reflects electric resistance heating. (PUCT 7/26/21 Work Session)



"BA staff, especially those in southern areas with substantial electric heat pump load, need to understand how changes in weather can be reflected in the above-illustrated auxiliary heating demand characteristics as supplemental heating sources are used during cold weather."

AMERICAN ELECTRIC POWER
BOUNDLESS ENERGY

Texas Valley Area Winter Peak Demand at Varying Probability Intervals

2019 Load Forecast