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ENERGY RESEARCH

Texas Competitive Transmission Study

September 29, 2026

Prepared for Texans for Affordable Transmission

Final Report

Context for this report

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- This report, prepared for Texans for Affordable Transmission, is an assessment of competitive procurement outcomes for large transmission projects across major U.S. power markets, and their implications for ERCOT's Sustainable, Transmission, and Economic Program (STEP) buildout. It evaluates cost, schedule, and innovation outcomes for competitively procured versus non-competitive transmission projects, including an estimate of the potential ratepayer savings from applying competitive procurement to STEP.
- The study includes a comparative analysis of completed transmission projects across six U.S. markets: SPP, MISO, CAISO, PJM, NYISO, and ERCOT's own CREZ[1] initiative, reflecting each region's distinct approach to transmission procurement.
  - Markets were classified as either "procurement model" (the RTO defines the project and developers compete head-to-head to build it) or "sponsorship model" (developers propose their own customized solutions), to assess how market structure affects outcomes.
  - Aurora selected a representative sample of competitive and non-competitive projects, comparable across length, terrain, and voltage class, to isolate cost and schedule differences attributable to the procurement method.
- Aurora further explored the potential impact of applying competitive procurement principles to ERCOT's STEP program on key retail rate outcomes, including CAPEX reduction, Transmission Cost Recovery Factory (TCRF) bill impact, and lifetime residential savings.

Disclaimer

- **This analysis rests on a limited sample of completed competitive transmission projects.** Few competitively procured projects have been completed since FERC Order 1000[2], and cross-market comparisons are affected by small sample sizes and, particularly for non-competitive projects, incomplete public cost and schedule data; findings should be read as directional rather than precise point estimates.
- **Retail rate impact figures are indicative,** based on preliminary STEP cost estimates and modeling assumptions (a 6.6% WACC,[3] a 40-year asset life, and benchmark savings drawn from SPP/MISO outcomes), not final CCN filings.
- **This report does not advocate for any specific policy or market design change** but rather aims to evaluate the potential impact of applying competitive procurement to ERCOT's STEP program.

1) Competitive Renewable Energy Zones (CREZ). 2) Requires public utility transmission providers to participate in regional planning, allocate costs in rough proportion to benefits, and eliminates the federal right of first refusal for certain new regional projects.
3) Weighted Average Cost of Capital (WACC).

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Executive Summary | Texas could reduce transmission costs through competitive procurement, provided strong market safeguards are built in

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1 Competition builds new transmission projects on schedule, at lower cost, and more innovatively

- Competitive projects finished on time or early in most markets studied, while also cutting costs. In two states, bidding lowered costs by about 19%.
- Competition also improved accountability, with problems caught and addressed sooner, and encouraged new engineering approaches and equipment that pushed down costs further.

2 Applying competition to future 765kV lines in Texas could cut costs by an estimated $2 to $7 billion, saving ratepayers up to $482 per household

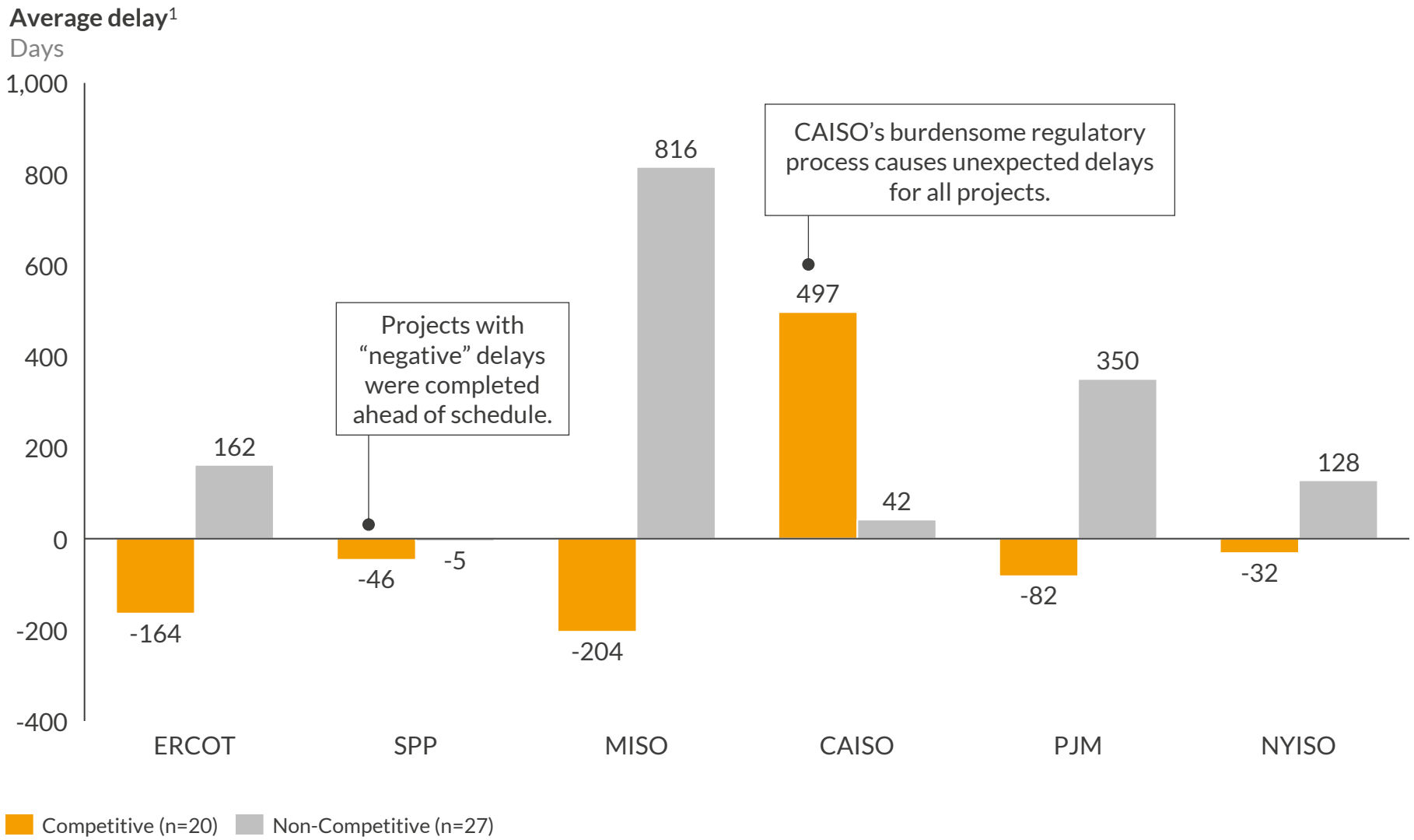
- Applying the same competitive approach to ERCOT's upcoming high voltage lines could lower costs by an estimated $2 to $7 billion.
- Over time, those savings could add up to $5 to $16 billion for all ratepayers, translating to $150 to $482 per household.

3 Savings can only be realized when the right safeguards work in combination: procurement, binding cost caps, and public accountability

- The biggest savings came from binding cost caps paired with real financial penalties for missing them, not competition alone.
- Public reporting of a developer's cost and schedule commitments adds another layer of accountability, making it easier to catch problems early and hold developers to their promises.

Sources: Aurora Energy Research

Competitive transmission projects have stayed on schedule across most markets, while non-competitive projects tend to face delays



1) Delays are defined as the difference between a project's actual in-service date and initially promised in-service date.

Sources: Aurora Energy Research, PUCT, FERC, SPP, MISO, CAISO, PJM, NYISO

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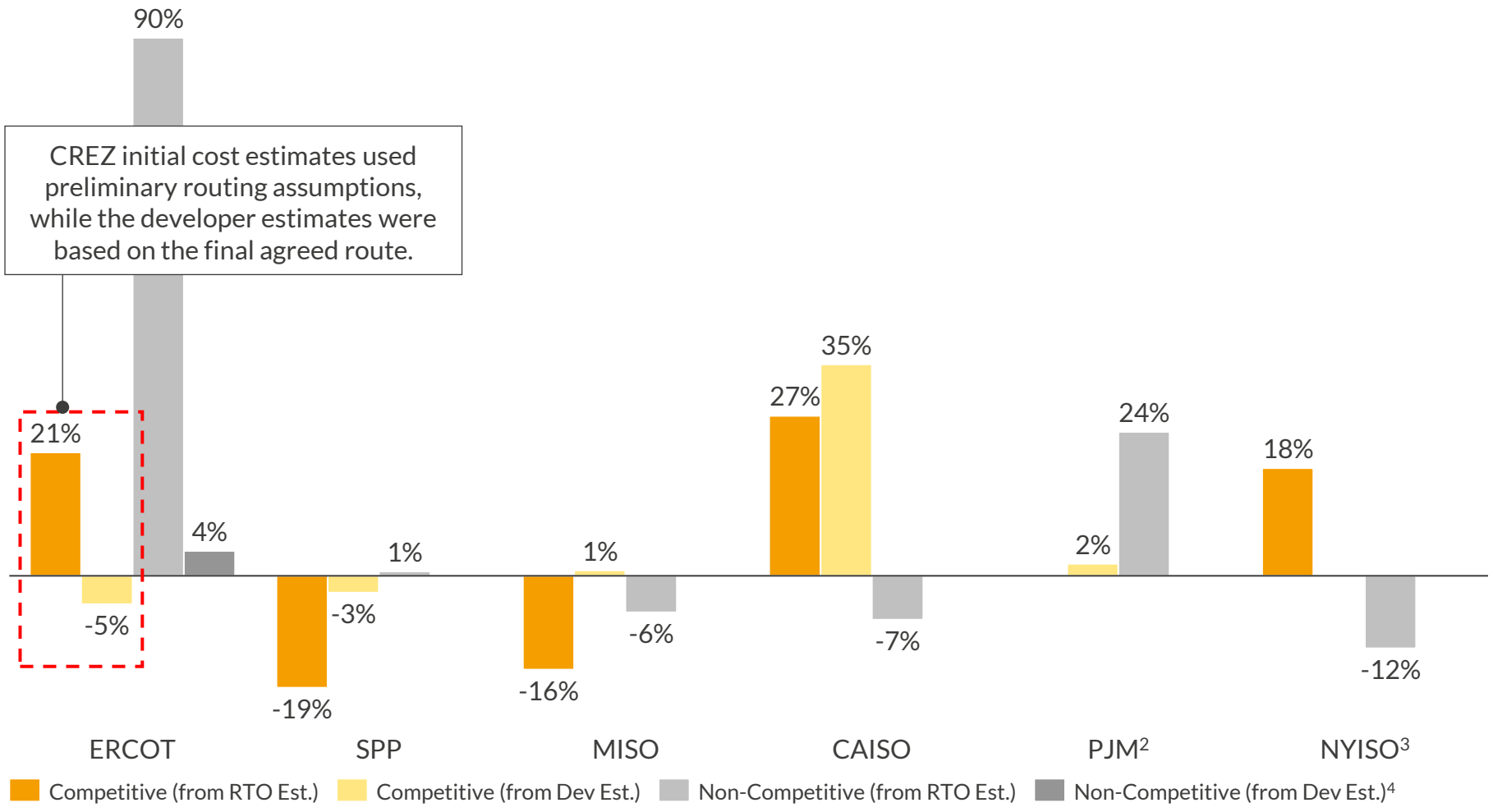
The average competitive projects have finished ahead of schedule in 5 of 6 markets

- Although unforeseeable delays can occur, non-competitive projects have been consistently delayed in nearly every market, as there are limited incentives to ensure proposed in-service dates are met.
- Meanwhile, competitive solicitation processes incentivize developers to complete projects on-time in order to win future projects. Some developers even commit to a Return on Equity (ROE) deduction punishment if their project is delayed to secure winning bids.

In 3 of 6 markets, competitive projects were successful at staying on or under-budget

Average project cost escalation[1]
% (initial to final cost)



1) Total project cost used, including any substations or other grid components. Final cost is the gross plant in-service cost of the project reported after energization. Aurora is tracking only the initial cost estimates from the RTO and the developer as well as the final cost. 2) No RTO estimates found for PJM competitive projects. 3) No developer estimates found for NYISO competitive projects. 4) Only the CREZ incumbent projects are included in the initial developer estimate for ERCOT. Sources: Aurora Energy Research, FERC, PUCT, SPP, MISO, CAISO, ERCOT, NYISO, PJM.

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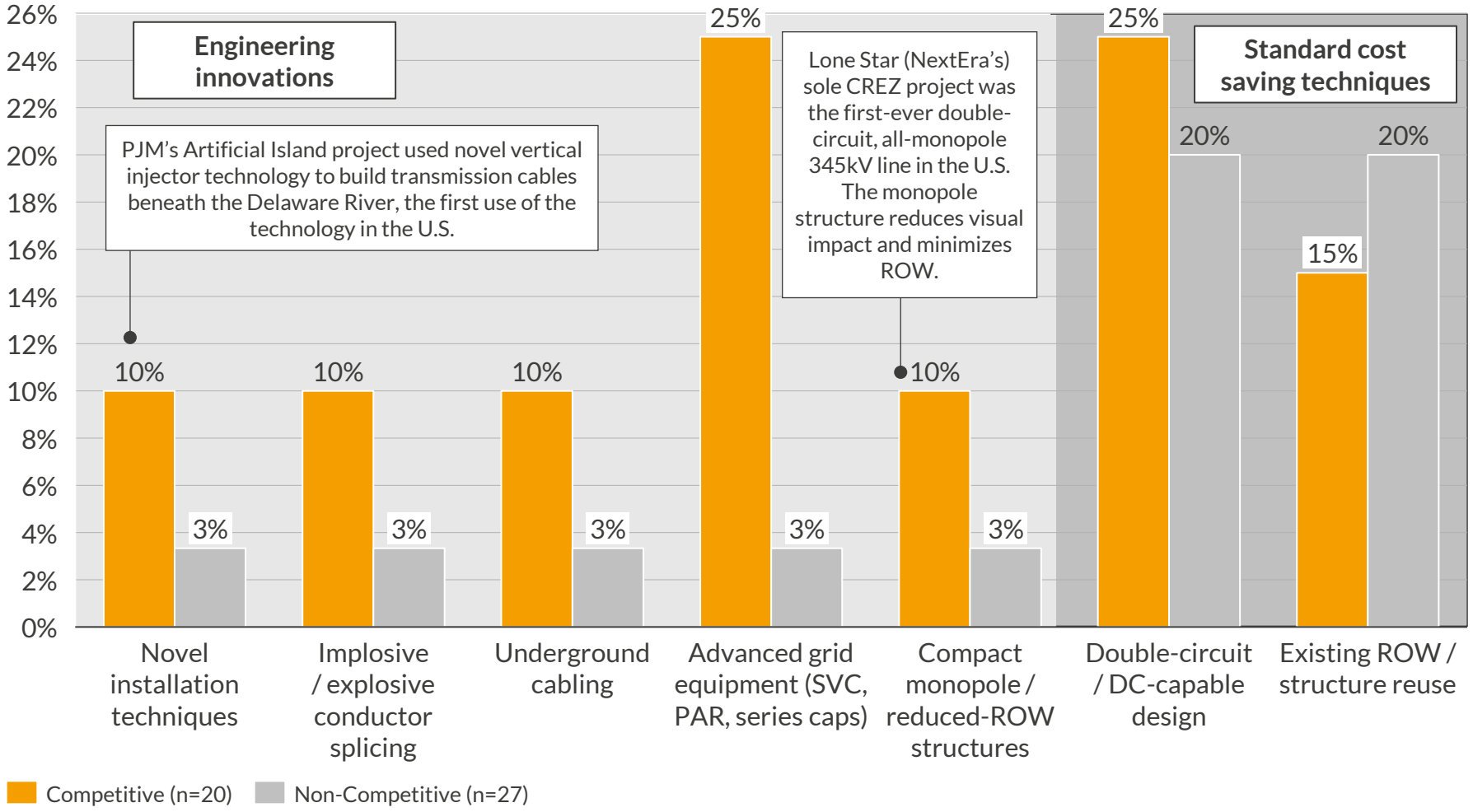
Competitive developers adhere to their initial cost estimates in SPP, MISO, and ERCOT

- SPP has shown the best cost outcomes from introducing competitive processes. The final costs were on average 19% lower than the RTO estimate, and 3% lower than the winning developer's estimate.
- CAISO has seen the highest cost escalations among competitive projects, driven by major route changes and multi-year permitting delays.
- The RTO estimates for CREZ project costs were based on straight-line distances between substations. Thus, the 21% cost escalation stems from inaccurate initial RTO estimates.
- Among competitively procured ERCOT CREZ projects, final costs came in 5% below developer estimates.

Competitive projects have been more likely to use advanced engineering and innovative techniques compared to non-competitive

Project design and construction innovations
Percentage of projects (%)[1]



1) Projects are assigned to any number of innovation categories. Some projects studied did not exhibit any innovations.

Sources: Aurora Energy Research, PUCT, FERC, SPP, MISO, CAISO, ERCOT, NYISO, PJM

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- Competitive projects have exhibited a **higher frequency of engineering innovations**, such as more novel conductor splicing, underground cabling, and never-before-seen designs and installation in the U.S..
- Non-competitive project developers, meanwhile, leverage their advantages:
  - They utilize **already-acquired Right-of-Way (ROW)** to minimize land acquisition, cutting costs, and lowering the risk of court challenges.
  - Their cables cross through existing double-circuit-capable towers, **reducing the number of new towers that need to be constructed.**

Across CREZ transmission projects, new entrants outperformed incumbents on final cost and cost escalation, with a similar performance on schedule

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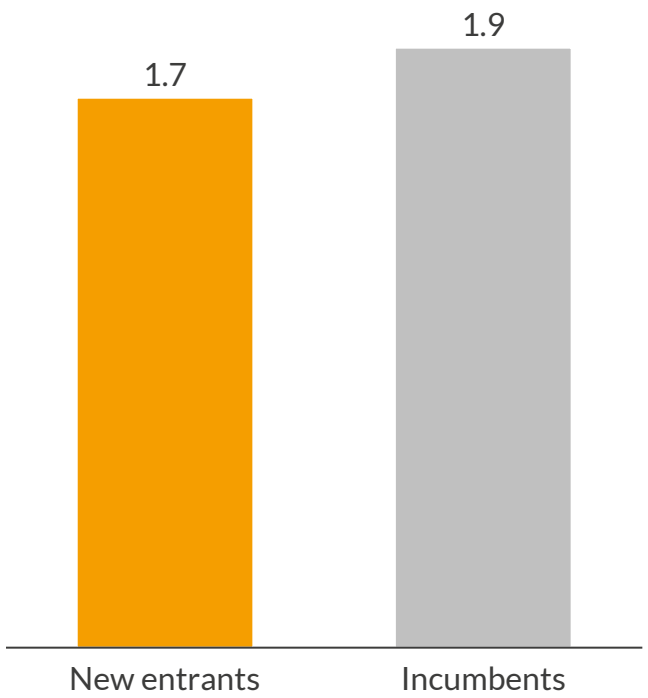
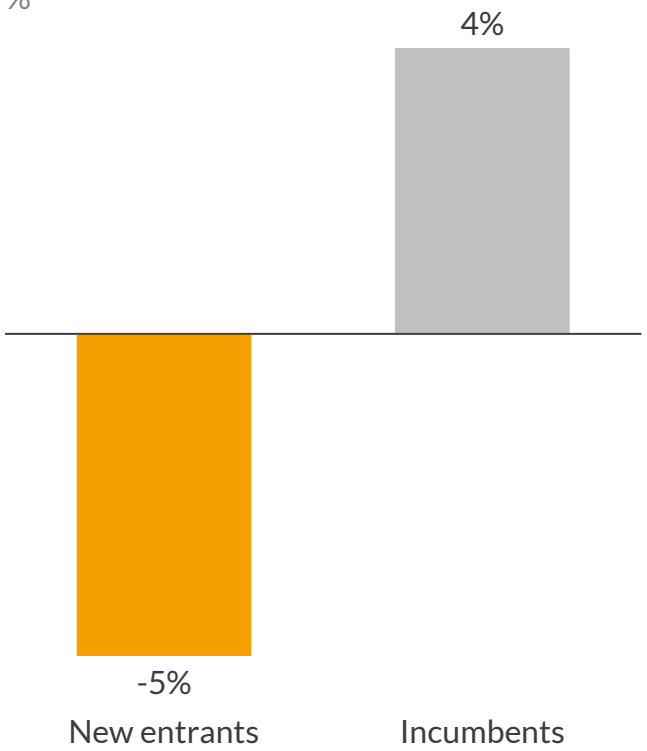
Project cost per mile, CREZ[1]
$ mn/mile (real 2025)



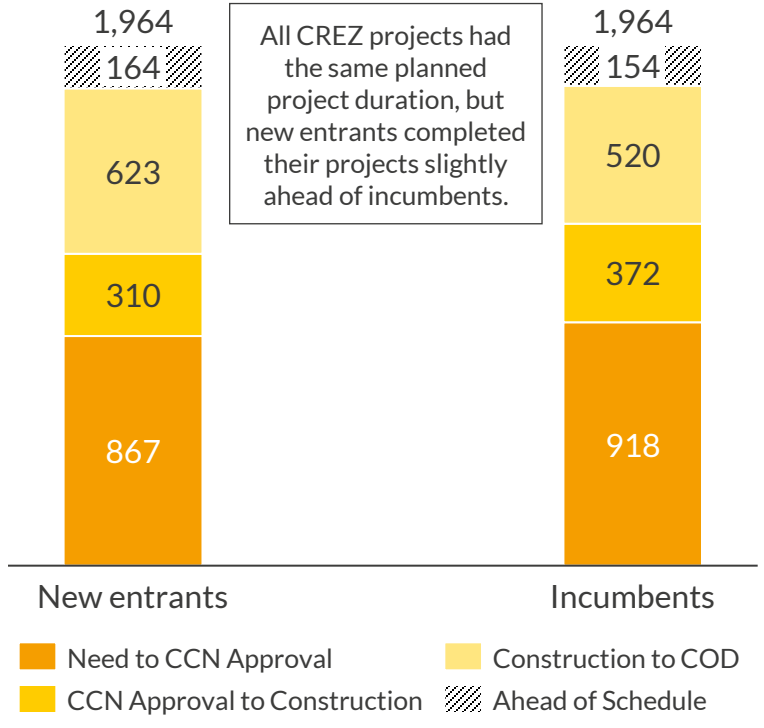
- Accounting for project scope, all CREZ projects saw relatively low costs, resulting from ERCOT's more relaxed regulatory environment and lower supply chain costs in the early 2010's.
- Nevertheless, new entrant project costs were ~$150k per-mile less, on average.

Cost escalation from initial dev. est, CREZ[2]
%



- 5 of 8 new entrant projects showed a negative cost escalation; in particular, WETT's Panhandle A D-Central B showed a 25% cost decrease.
- No incumbent projects exhibited cost decreases, demonstrating that incumbents have less incentive to cut costs than new entrants.

Planned and actual project duration, CREZ[3]
Days



- While nearly all CREZ projects met the scheduled completion of year-end 2013, new entrants completed projects slightly faster, despite larger scope (Lone-Star's 330-mile line[4]).
- New entrants exhibited faster CCN[5] acquisition, despite a more burdensome regulatory process.[6]

1) Line-only final cost, excluding substation costs. 2) Initial developer estimate defined as initial cost given in final Certificate of Convenience and Necessity (CCN) order. 3) Project duration defined as days between 8/15/2008 (date CREZ designated and approved) and project energization. 4) Lone Star Transmission is an indirect wholly-owned subsidiary of NextEra Energy, Inc. 5) Certificate of Convenience and Necessity (CCN). 6) While incumbents building CREZ projects had to merely amend their existing CCNs, new entrants had to file entirely new CCNs. Sources: Aurora Energy Research, PUCT, ERCOT

To realize the benefits of competitive transmission, key elements of success have appeared to be critical

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Markets with the following characteristics have shown **average savings of 19%** from the RTO estimate for a competitive project.[1]

1

"Procurement" model

Used in SPP, MISO, CAISO, and ERCOT's CREZ initiative, this model, where developers compete to win the bid on predefined projects on price, timeline, etc., demonstrates stronger competitive outcomes across costs and time.

2

Binding cost caps with ROE penalties

SPP and MISO select developers that promise hard cost caps and schedule commitments, with punishments for not meeting them.

3

Regulatory transparency

By making public the winning developer's cost and schedule commitments, SPP holds the developer accountable to deliver on their commitments.

1) This number is calculated by averaging the percent change in project cost, from initial RTO estimate to final, for all completed competitive projects in SPP and MISO.

Sources: Aurora Energy Research, FERC, PUCT, SPP, MISO, CAISO, ERCOT, NYISO, PJM

Retail Rate Impact | Competitive bidding on Texas's largest transmission projects could save households up to $482 each

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Texas is planning over $36 billion in new 765kV transmission lines, therefore controlling costs is a major issue

- Texas is planning over $36 billion in new 765 kV transmission lines, in addition to the larger investment in the transmission infrastructure taking place. Transmission charges already make up 15% of a typical Texas power bill and have risen 34% in just two years.
- Four major 765kV projects, the Permian Basin Reliability Plan, the Eastern Backbone, the Western Loop, and the Central Texas project, could be candidates for competitive bidding due to their high-voltage greenfield lines and interregional benefits.

If the major 765kV projects are bid competitively, all ratepayers could save $5 to $16 billion, translating to $150 to $482 per household, over the life of the projects

- Based on savings seen in other states, competitive bidding could lower construction costs by $2 to $7 billion, save all ratepayers $5 to $16 billion and individual households $150 to $482 over the life of the projects.
- Competitive bidding shifts the risk of cost overruns from ratepayers to the developer and requires more upfront transparency about pricing.

Sources: Aurora Energy Research

ERCOT's future high voltage projects are potential candidates for competitive processes, due to their high-voltage greenfield lines and interregional benefits

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1 Permian Basin Reliability Import Paths

765kV | AEP / CPS / Oncor / LCRA

~$13.8bn | ~810 mi | ISD[2]: 2029-30

Developer selection status: CCNs opened for 5 of 5 lines by incumbent utilities, and three CCNs have been approved to finalize the developers as of September 16, 2026.

Regional benefits: Sends power to the Permian Basin to meet increased demand due to oil & gas electrification.

Notes:
- $9.1bn estimate from 765kV lines and substations only, $4.7bn estimate of lower-voltage grid components.
- Endorsed by ERCOT.

2 Western Loop

765kV | TSP Not yet confirmed[1]

~$0.7bn | ~161 mi | ISD[2]: 2030

Developer selection status: No developers selected and no CCNs filed.

Regional benefits: Complements the Permian Basin Reliability Plan by allowing bulk power flow across the Basin, not just to and from.

Notes:
- Standalone extension of the Permian Basin import paths, first presented in the July 2025 RPG meeting.
- Endorsed by ERCOT.
- As of September 16, 2026, no lower voltage supporting lines have been announced.

3 Eastern Backbone

765kV | TSP not yet confirmed[1]

~$20.5bn | ~1.1k mi | ISD[2]: 2030-32

Developer selection status: No developers selected and no CCNs filed.

Regional benefits: Reduce congestion and serve demand driven by population growth, electrification, and data centers in the Texas Triangle.[4]

Notes:
- $8.1bn estimate in 2024 RTP for 765kV lines only, updated to $9.4bn estimate in 2025 RTP.
- $11.1bn estimate in 2024 RTP for lower-voltage grid components.
- Endorsed by ERCOT.

4 Central TX (Euclid-Hillje)

765kV | TSP not yet confirmed[1]

~$1.4bn[3] | ~130 mi | ISD[2]: 2031

Developer selection status: No developers selected and no CCNs filed.

Regional benefits: Relieve the constrained Central Texas import corridor from the Gulf Coast.

Notes:
- Standalone of the Eastern Backbone project, first presented in the November 2025 RPG meeting.
- Endorsed by ERCOT.
- In August 2026, ERCOT filed additional details, including a supporting 345kV line from Euclid-Misty, though cost breakdowns are not currently available.

1) Final transmission service providers for these projects have yet to be assigned by the PUCT, though ERCOT has proposed various TSPs in its endorsement of each project. 2) Stands for in-service dates. In-service dates are preliminary and pending additional market stakeholder updates, given recent developments and the suspension of Permian transmission plan CCNs. 3) Estimated cost prior to inclusion of Euclid-Misty line, though if an extra line is opened to competition, cost savings could improve. 4) The Texas Triangle refers to the megaregion bounded by Dallas–Fort Worth, Houston, San Antonio, and Austin. Sources: Aurora Energy Research, ERCOT, ERCOT 2024 RTP, ERCOT 2025 RTP, PUCT

Savings for residential ratepayers could become meaningful if a large portion of planned high voltage projects were to be competitively procured

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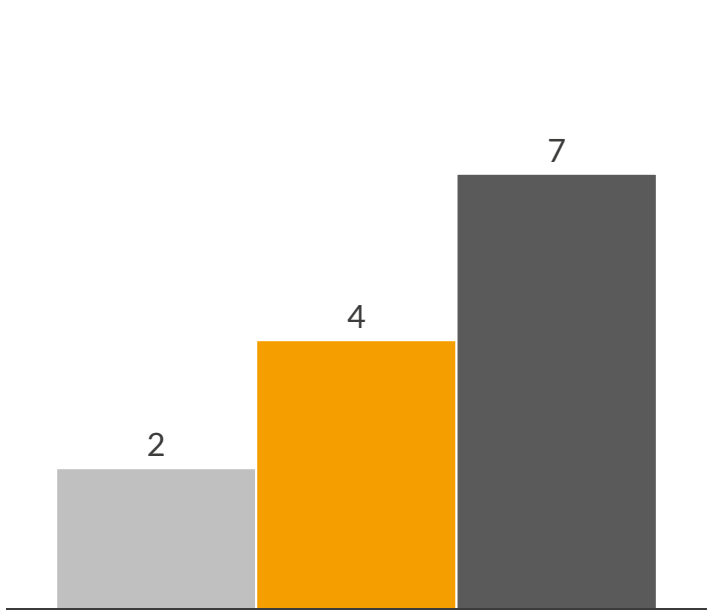
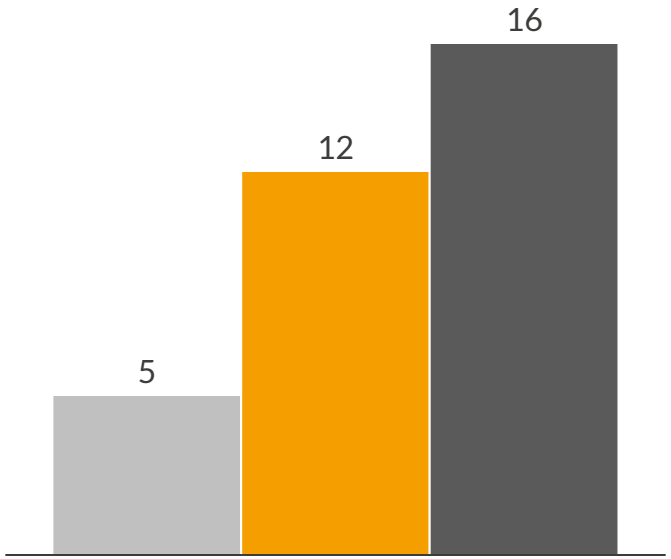
Upfront CAPEX Savings

$bn (real 2025)



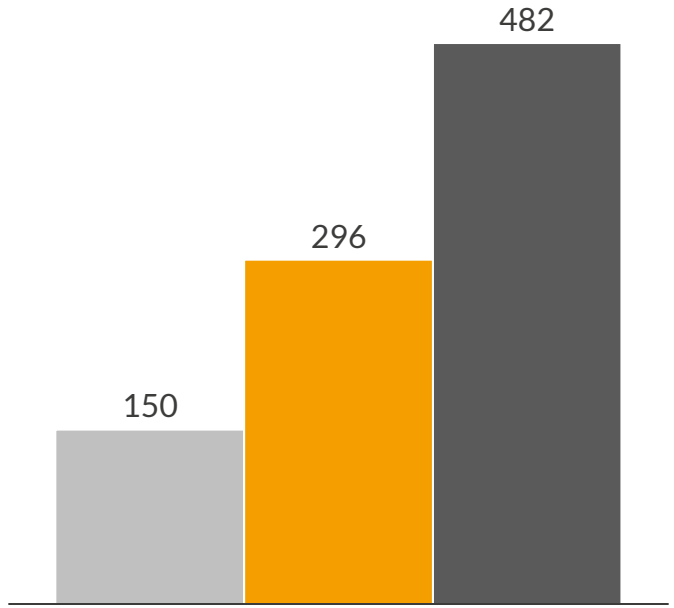
Total Lifetime Ratepayer Savings

$bn (real 2025)



Total Lifetime Savings per Household

$/residential account (real 2025)



765kV only, Permian excluded | 765kV and all 345kV upgrades, Permian excluded | Complete STEP Allocation

- The 2024 and 2025 ERCOT RTP's outlined $36 billion in allocated costs for the entire STEP Program. Excluding the Permian import path projects leaves $13.8 billion and further excluding all lower-voltage lines and upgrades leaves ~$9.1 billion. Reconsideration of Permian 765kVs for competitive allocation has the potential to contribute nearly $3 billion to upfront CAPEX savings.
- Consideration of all unallocated lines alone (765kV only, Permian excluded) provides a potential opportunity to achieve ~$5 billion in lifetime ratepayer TCRF[1] savings.

1) Transmission Cost Recovery Factory (TCRF).

Sources: PUCT, AEP , ERCOT, CNP, Oncor, Aurora Energy Research

Competition on future high voltage lines could significantly reduce CAPEX and help offset rising transmission charges for ERCOT residential ratepayers

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~19%
CAPEX savings assumption
Successful competitive projects average

~$7 billion
Potential STEP capex reduction
~$36.4bn to ~$29.6bn

~$16 billion
Lifetime total ratepayer savings
If eligible STEP programs are built collectively

~$482
Lifetime savings per household
Service-area-wide estimate

1 Procurement design determines who bears risk

- Non-competitive projects are assigned to incumbents
- Cost overruns can flow through regulated rates
- Competitive bids add price discovery, caps and disclosure

2 Transmission charges already matter on bills

- TCRF contributes 5-15% of a typical bill
- Representative TCRF is ~2.19¢/kWh
- TCRF increased ~34% over the last two years

3 These lines are a natural target for savings

- Competitive path implies ~$36.4bn vs ~$29.6bn baseline
- Rate model indicates up to -0.21¢/kWh residential impact in a single year[1]
- Maximum 5-year residential savings of ~$116 per customer[1, 2]

Introducing competition for eligible STEP projects can transfer performance risk to developers, create cost discipline, and convert CAPEX savings into direct TCRF relief for customers[3].

1) All figures indicative and based on current benchmark assumptions, filed ROEs, Aurora rate model inputs and preliminary STEP cost estimates. 2) 5-year period is 2032-2036. 3) 2033.

Sources: Aurora Energy Research, PUCT, AEP , ERCOT, CNP, Oncor

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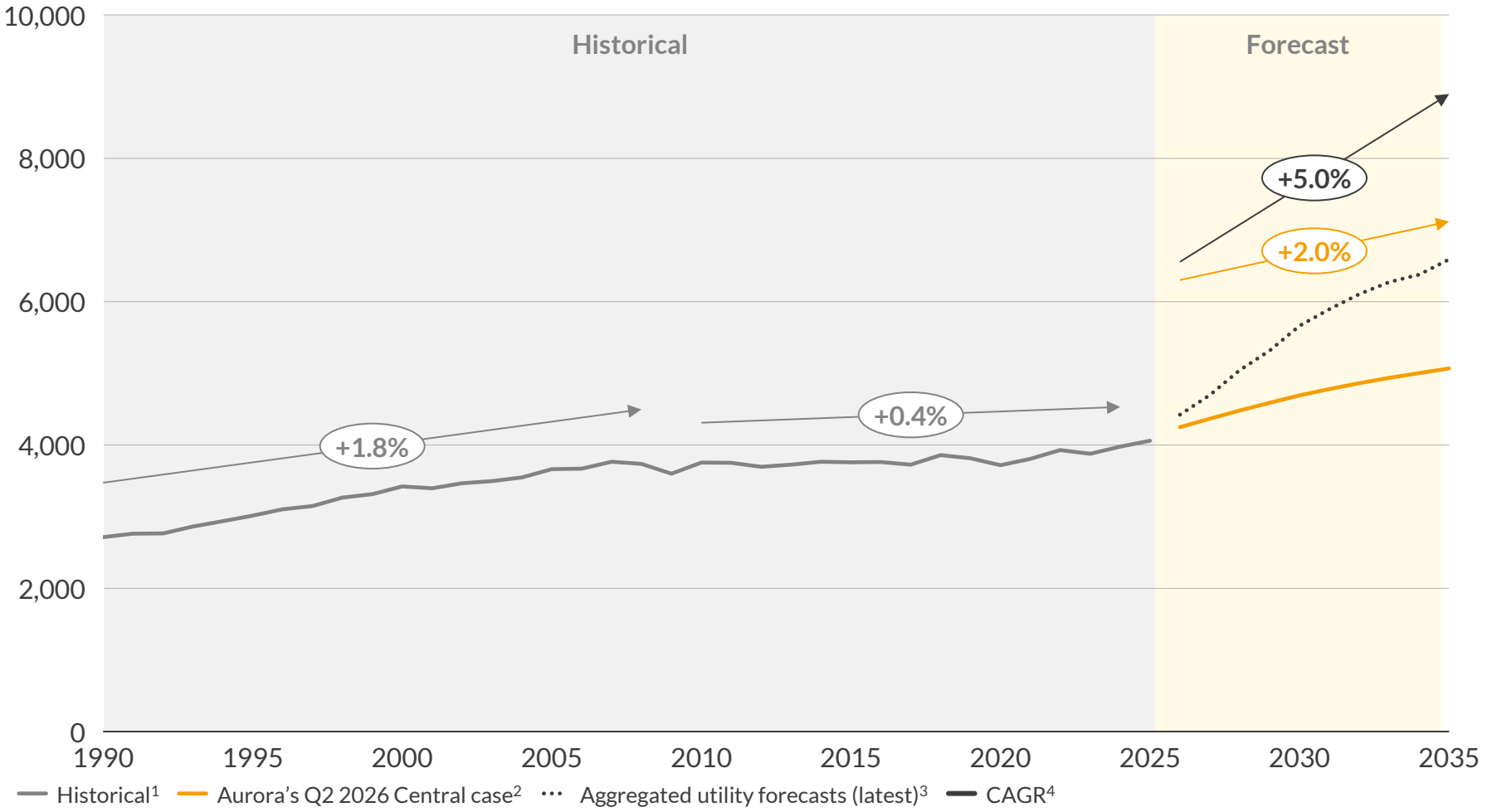
U.S. power demand is accelerating after years of flat growth, with structural load drivers supporting a higher-growth outlook

Historical and forecasted U.S.-wide load
TWh



1) Historical data from EIA Monthly Energy Review Electricity overview. 2) From Aurora's Q1 2026 Central scenario. 3) ISO-NE, MISO, NYISO, and PJM forecasts are from 2026; CAISO, ERCOT, and SPP from 2025. WECC and SERC are aggregated from individual BA IRPs (publication dates range from 2023–2026). 4) Compound Annual Growth Rate.
Sources: Aurora Energy Research, Individual ISOs and BAs, Brattle, EIA, Utility Dive

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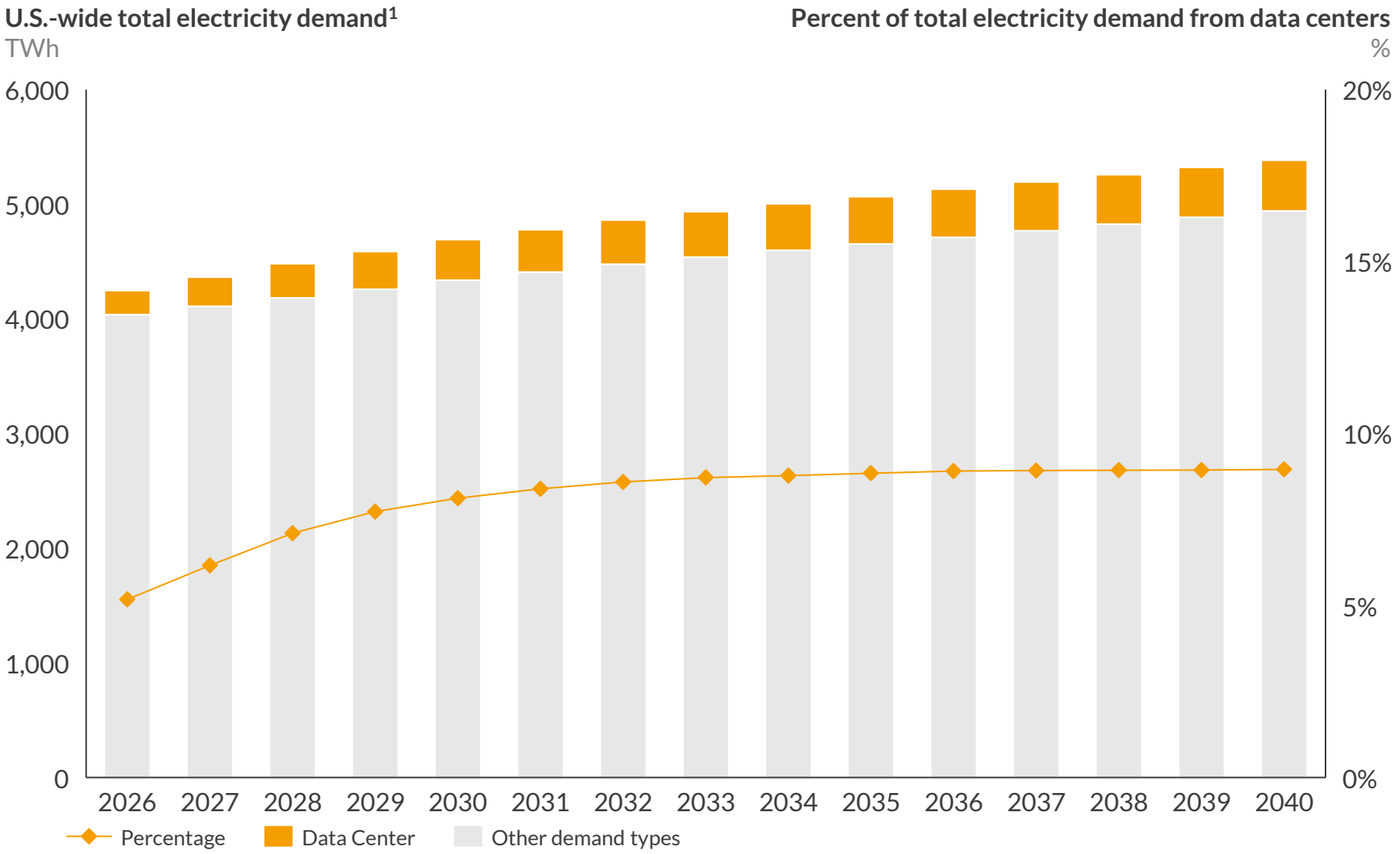
Structural load growth is reshaping long-term power system planning

- **U.S. load growth slowed materially from 2010–25**, averaging +0.4% per annum compared with +1.8% per annum from 1990–2010.
- **Load growth is now accelerating again**, driven by structural demand from data centers, bitcoin mining, reshored manufacturing, and electrification rather than traditional drivers such as population growth and weather.
- **Utility forecasts show U.S. load growing at +5.0% per annum through 2035**, nearly doubling demand and pulling forward the need for new generation and transmission infrastructure.

Data centers are emerging as a primary driver of electricity demand growth



1) U.S.-wide electricity demand accounts for markets across CAISO, ERCOT, ISO-NE, NYISO, MISO, PJM, SPP, SERC, and WECC.

Sources: Aurora Energy Research

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- **Data centers have emerged as a primary driver of electricity demand growth**

  Aurora projects total U.S. power demand rising from ~4,247 TWh in 2026 to ~5,384 TWh by 2040, with data centers taking a growing share of that increment.

- **Data center demand is expected to nearly double over the forecast period**

  Data center demand grows from 209 TWh in 2026 to 443 TWh by 2040, a ~2x rise that drives most net new load.

- **Without data center growth, the demand curve would be comparatively flat**

  Baseline load grows only from 4,038 TWh to 4,941 TWh, making data centers the critical swing factor for transmission planning.

ERCOT faces the largest large load queue among major markets in the U.S. and is quickly catching up to installed data center capacity in Northern Virginia

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Market	Large loads and data center queues			Large loads interconnection status and reform overview		
	Large load queue,[1] GW	Data center capacity by status,[2] GW	Median data center size by status, MW	Overview of load interconnection reform and other new requirements for load	ISO-wide study deposit[3]	ISO-led large loads tariff rate reform
ERCOT	115	42	9 / 50	**SB 6** sets a deposit, requires backup power disclosure, and authorizes ERCOT to curtail power to large loads with ≥50% backup generation during emergencies. NPRR1234 and PGRR115 update modeling, interconnection, and data requirements for loads ≥75MW.	$100k	SB 6 directs the PUCT to update the current 4CP cost allocation methodology for transmission costs.
PJM	114	94	17 / 50	PJM launched a Critical Issue Fast Path for Large Load Additions in August 2025; the latest proposal includes i) an **Expedited Interconnection Track** for new loads compliant with **BYONG**[5], and ii) a **Connect and Manage** program for curtailment.	None	Many undergoing reform, expect further reform with BYONG.
SPP	30	20	7 / 65	FERC approved **HILL/HILLGA** for large loads on January 14, 2026. CHILL/CHILLS was approved by SPP's Markets and Operations Committee on January 13, 2026, and is awaiting board approval before being submitted to FERC.	None	N/a
CAISO	Unavailable	4	6 / 30	No reform underway.	None	SB57 enacted in July 2025 to prevent rate-payers shouldering costs of large load interconnection.
MISO	64[4]	21	2 / 50	MISO is considering a 'zero-injection' GIA type to allow generators to locate at the same POI as large load without injecting into the grid. State PSCs have approved rate settlement agreements for Ameren and Consumers Energy large load customers.	None	N/a
NYISO	12	1	3 / 38	No reform underway.	$150k	No reform underway.
ISO-NE	Unavailable	1	3 / 26	No reform underway.	None	N/a

Operational data centers Data centers in interconnection queue

1) Large load queue data based on Baxtel data, not ISO-reported queues. 2) Represents total power draw, meaning IT load + cooling + lighting + backup. 3) DOE order may create a standard study deposit across all regions overseen by FERC. 4) From their large load pilot study from entities representing 74% of MISO's total energy 5) Bring Your Own New Generation.

Sources: Aurora Energy Research, Baxtel, NERC, LBNL, individual ISOs

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ERCOT forecasts total annual load to hit ~980TWh in 2030 with peak load at ~139GW, driven by population, economic, and industrial growth

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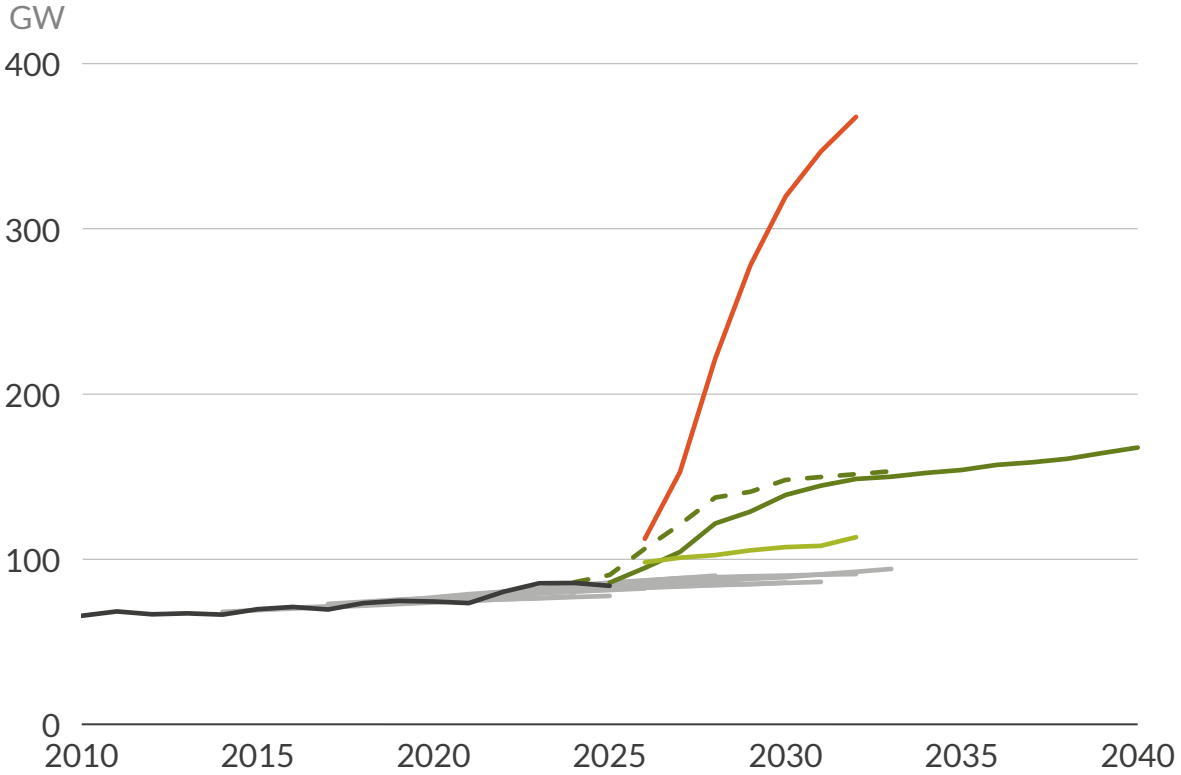
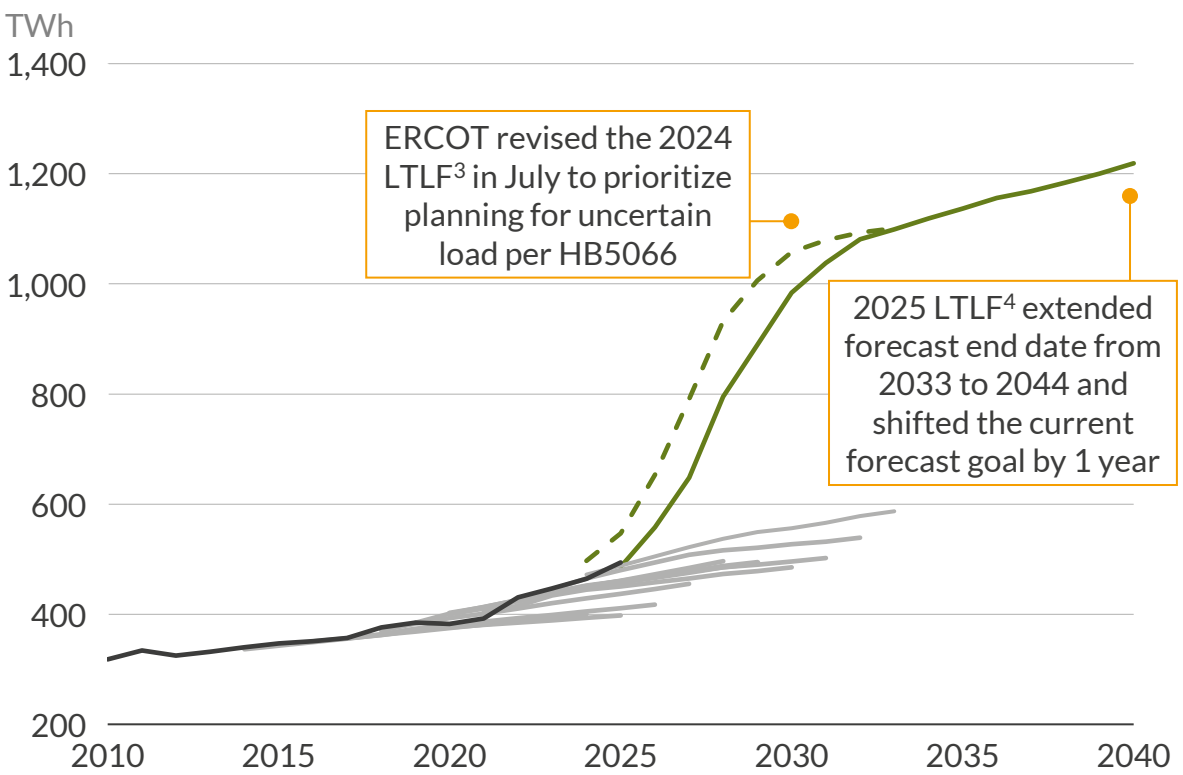
ERCOT peak load[1]



- Aurora assumes a peak load forecast reaching 109GW by 2030, compared to 107GW from ERCOT's 2026 LTLF less queued medium and large loads.
- Future peak and annual demand growth are driven by economic growth, data centers, industrial development, and HVAC.

ERCOT total annual load[2]



- Annual energy demand is set to increase alongside peak demand and reaches 984TWh in ERCOT's 2025 LTLF.
- Beyond 2030, demand growth is driven by population, industrial and data center growth, and transport electrification, offsetting efficiency gains.

Historical — ERCOT 2025 LTLF[4] — Revised ERCOT 2024 LTLF[3] — Previous ERCOT forecasts — 2026 LTLF - Forecast[5] — 2026 LTLF - Forecast + Medium + Large loads[5]

1) Summer peak demand. 2) ERCOT 2026 total annual load forecast not yet released. 3) Revised 2024 Long-Term Load Forecast, released July 2024. 4) 2025 Long-Term Load Forecast, released April 2025. 5) ERCOT 2026 LTLF displayed both with and without inclusion of all medium and large loads in the interconnection queue.

Sources: Aurora Energy Research, ERCOT

Electricity generation and demand are increasingly separated from one another in ERCOT, driving transmission constraints in key corridors

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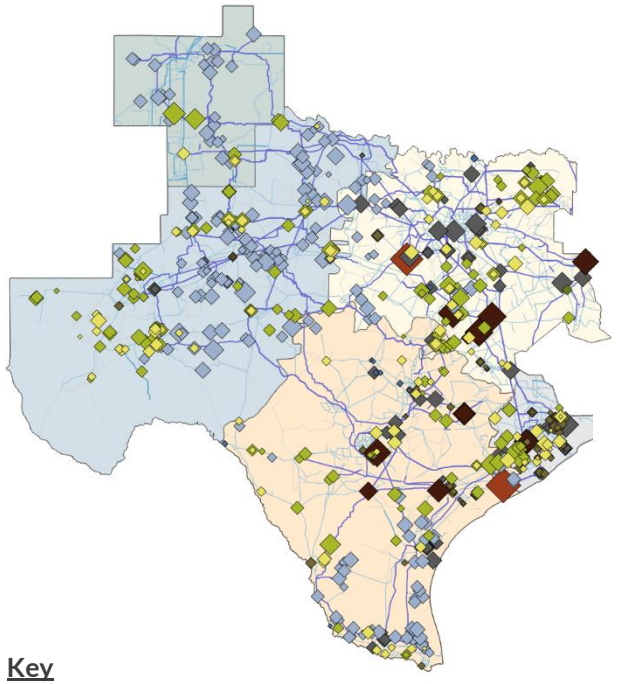
1 In and near the Permian Basin, solar and BESS capacity have grown in recent years

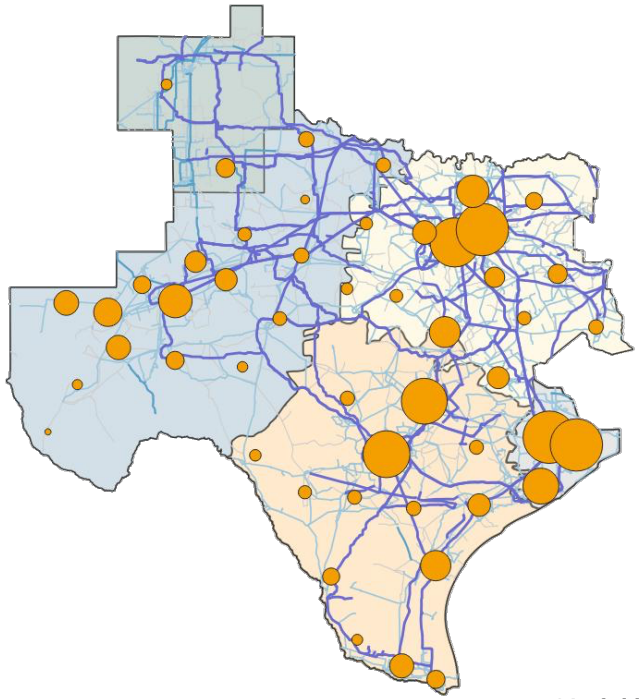
2 Driven by rising electrification, load across Far West Texas is rapidly growing

3 Transmission lines were often overloaded as local generation could not meet demand

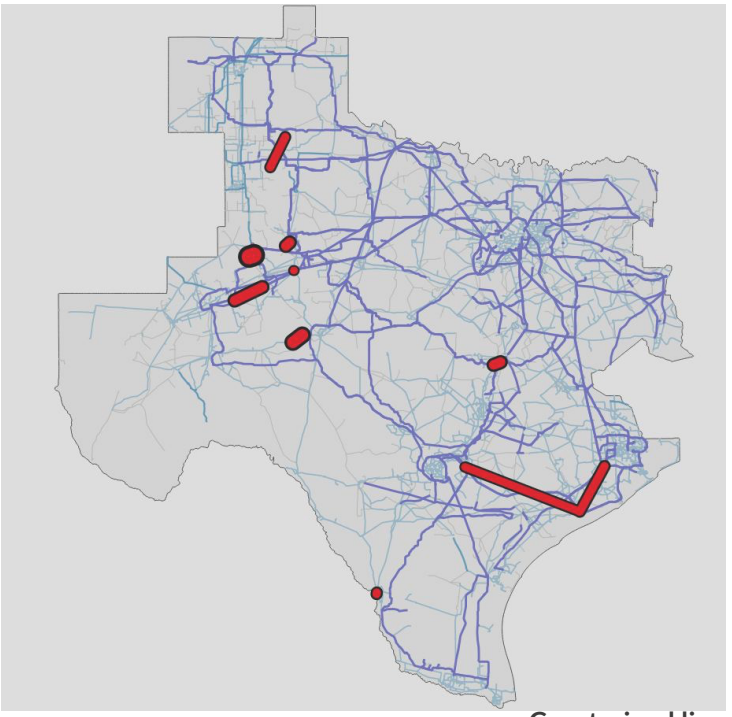
ERCOT installed capacity,[1] 2025[2]



ERCOT nodal demand,[3] 2025



Top severe and chronic constraints, ERCOT, 2025[4]



Key

Technology

- Gas CCGT
- Coal/Lignite
- Solar
- Onshore Wind
- Peaking
- Battery Storage
- Nuclear
- Other thermal
- Hydro

Network

- Existing <100kV lines
- Existing 100+kV lines
- Existing 345kV lines

Nodal load

Increasing load

Constrained lines

Increasing magnitude

1) Locations are approximate, and some projects are overlapping. Only generation assets above 10MW nameplate are shown. 2) 2025 data until December, using 2026 January EIA 860 report. 3) Demand aggregated using 2025 Summer Base case ERCOT 2024 SSWG nodal snapshot. 4) As reported in the Chronic and Severe Congestion and Constraints monthly reports.

Sources: Aurora Energy Research, ERCOT, EIA, Baxtel

ERCOT's growing transmission needs are driving a $32 billion buildout, increasing the importance of cost- and time-efficient delivery

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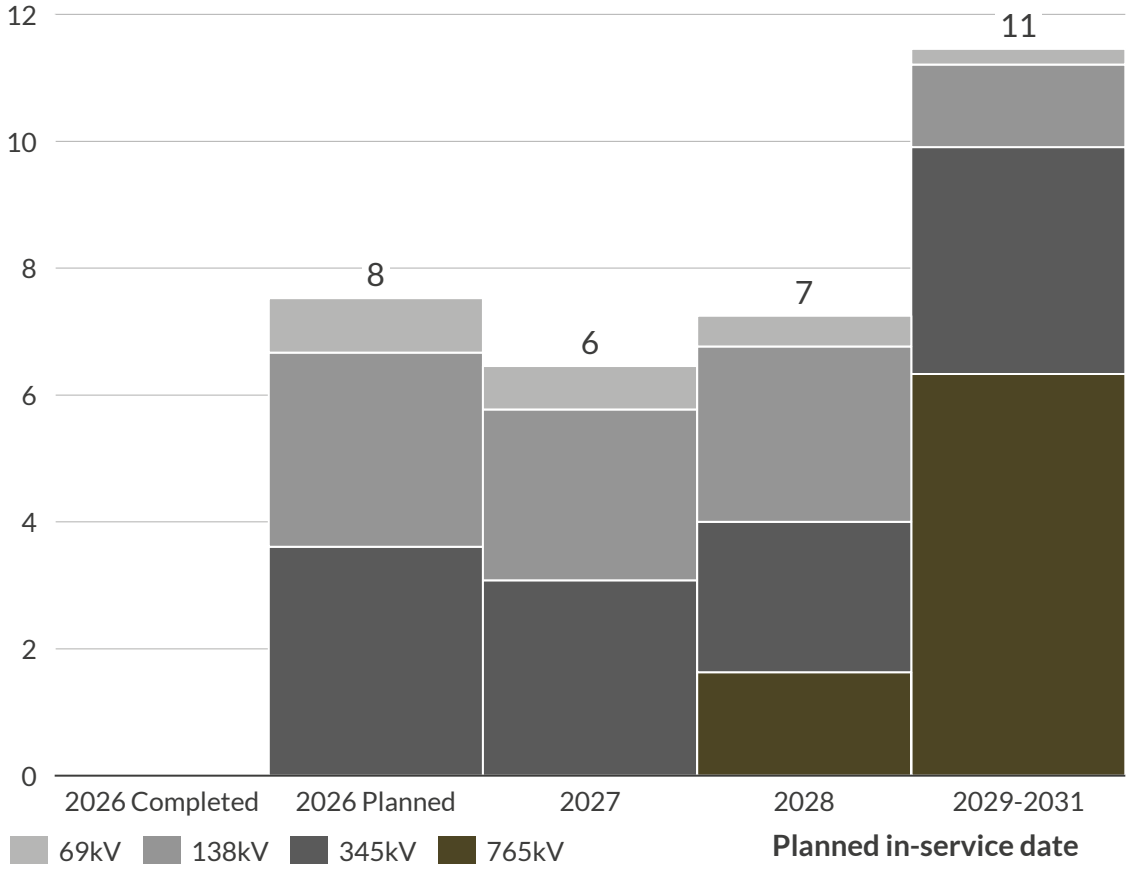
1 Rapid load growth is driving a major transmission buildout

Cumulative cost of scheduled transmission projects by voltage
$bn (nominal)



2 As ERCOT's transmission buildout accelerates, how projects are developed will increasingly shape costs and timelines

$32bn
in planned transmission upgrades from 2026-2031

$14bn
in expenditures expected 2026–27

- ERCOT is planning ~$32bn of transmission investment over the next half decade, including nearly $14bn in 2026–27 alone, reflecting the scale and near-term pace of system buildout.
- This total could rise even higher with the full inclusion of the Eastern Backbone package of transmission projects.
- Transmission investment has already risen materially, from ~$2bn in 2013 to nearly $5bn in 2024, while congestion costs increased from ~$6/MWh to greater than $10/MWh over the same period.[1]
- With significant capital deployment ahead, delivering transmission on time and at an efficient cost is increasingly important for ERCOT and ratepayers.
- Competitive transmission offers an alternative development model, allowing developers to compete on cost, cost containment, technical design, schedule, and execution.

1) From ERCOT Report on Existing and Potential Electric System Constraints and Needs, Dec 2025.

Sources: Aurora Energy Research, ERCOT

With rising demand in Far West Texas, ERCOT has identified elevated risks of load shed due to low local generation and lacking transmission import capacity

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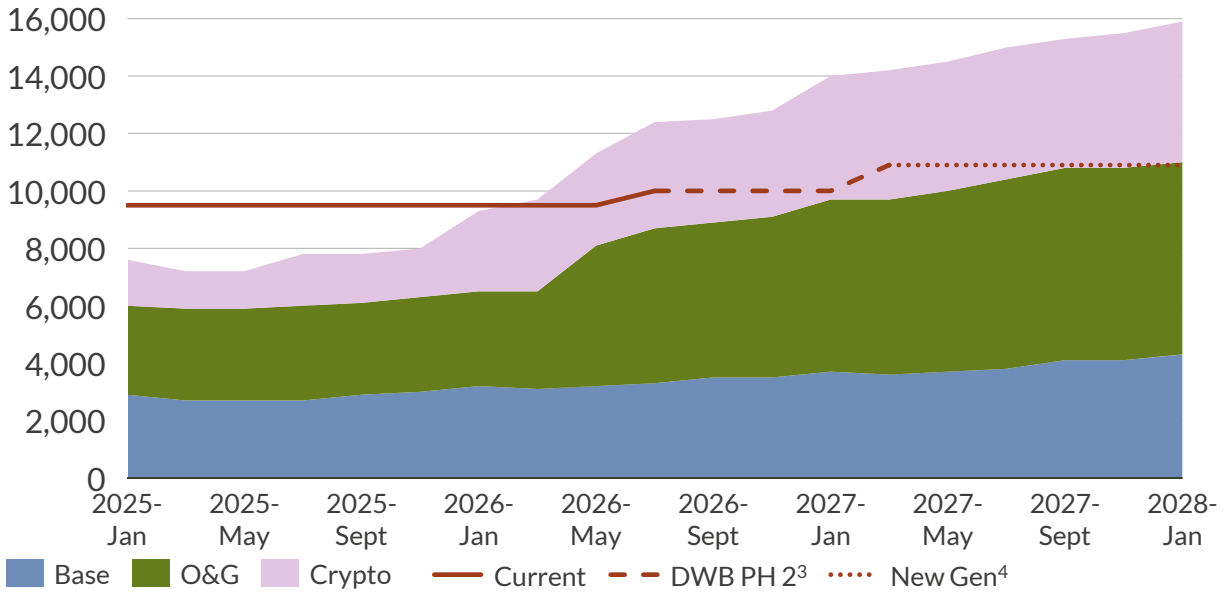
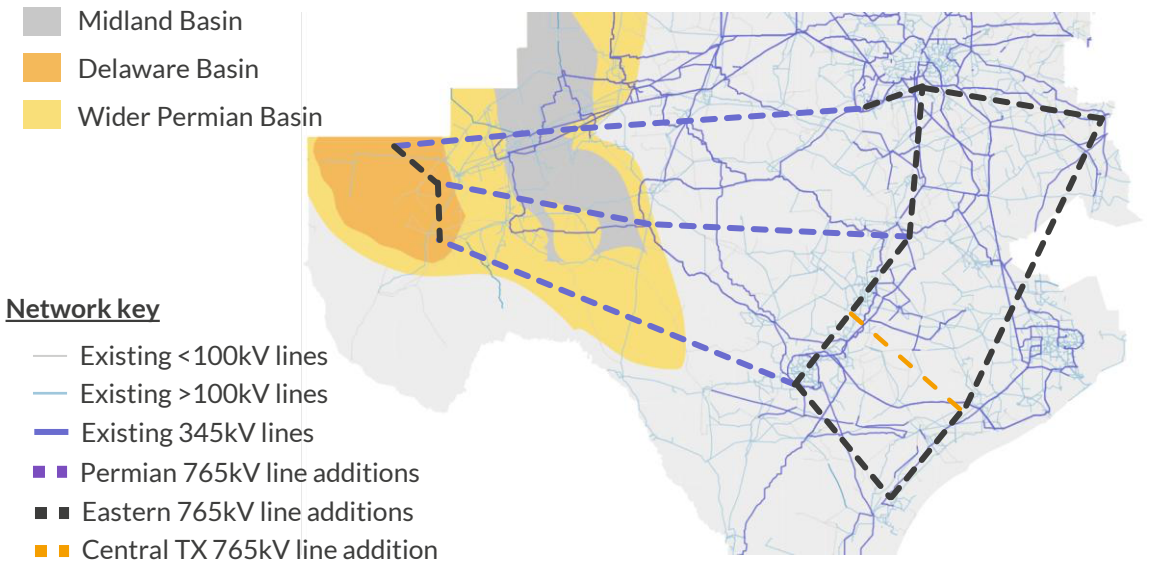
1 ERCOT identified potential load serving issues in Far West Texas, due to rising demand, the local generation mix, and limited power import capacity

ERCOT's Far West Load Forecast with load serving capability in low solar/wind conditions,[1] MW



2 As a solution to load serving capability shortfalls, market stakeholders have proposed a buildout of large transmission projects across the state

Proposed 765kV lines across ERCOT, including Permian and Eastern segments[2]



Key Trends:

- Changing business practices, increased extraction, new technologies, and relatively low power costs have led to an electrification of oil and gas activities in the Permian and Delaware Basins, increasing electricity demand in a low baseload generation area.
- ERCOT released materials in February 2026 highlighting the risks of local load shed in Far West Texas, which are greatest in overnight periods of low local wind and once local BESS have spent their state-of-charge.
- These risks demonstrate the growing need for improvements in the transmission system, especially in areas of mismatched power generation and demand.

1) Per ERCOT, load serving capability assumes "no transmission/generation outages, no solar generation, 1GW of local wind generation, and no BESS/ESR discharge though [BESS would be] providing voltage support." 2) From 2024 Regional Transmission Plan (RTP) 345-kV Plan and Texas 765-kV Strategic Transmission Expansion Plan (STEP) Comparison. The most recent 2025 RTP did not change or remove any element of the 765-kV STEP. 3) Represents increase in load serving capability with completion of Delaware Basin (DWB) transmission projects. 4) Represents increase in load serving capability from COD of the 224MW Tolivar Power Plant in Q2 2027. Sources: Aurora Energy Research, ERCOT

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FERC Order 1000 opened transmission development to competition, driving adoption across multiple U.S. markets

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Pre-Competitive

Pre-2011 | Incumbent-led transmission model

Regional transmission was historically developed primarily by incumbent utilities, with limited opportunities for non-incumbent developers.

CAISO, PJM, and MISO

2013 and 2014 | Competitive frameworks take shape

CAISO and PJM established competitive processes allowing incumbent and non-incumbent developers to propose solutions for regional transmission needs.

Competitive Projects Awarded

2015 – Today | Ongoing competitive solicitations

Competition solicitations across U.S. markets have allowed ISOs to compare developers on proposed cost, cost containment, technical design, schedule containment, and execution.

Duff to Coleman Transmission Line

June 2020 | First Order 1000 competitive project energized

The Duff–Coleman 345-kV project, connecting southern Indiana and western Kentucky, became the first competitively selected transmission project under FERC Order 1000 to enter service in the U.S.

2011 — 2014 — 2019 — 2026

FERC No.1000

July 2011 | FERC Order 1000

FERC issued Order 1000, requiring removal of federal rights of first refusal (ROFR) for certain regional projects across FERC-jurisdictional markets, including PJM, MISO, SPP, CAISO, ISO-NE, and NYISO, opening eligible projects to non-incumbent developers.

Deep dive on the following slide

SPP

2015 | First competitive RFP process

SPP implemented its Transmission Owner Selection Process, requiring competitive RFPs for eligible transmission projects approved after January 1, 2015.

Qualified developers can compete to construct, own and operate these facilities.

Texas SB1938

2019 | Texas reinforces incumbent ROFR

Texas enacted SB 1938, effectively limiting transmission development to incumbent utilities and restricting non-incumbent competition.

Competitive Transmission Process Today

Today | Competitive transmission landscape

~19 competitively bid transmission projects have entered service across U.S. markets, with dozens more in development or solicitation.

Competitive transmission is now established across multiple RTO/ISO markets.

Despite significant transmission needs, ERCOT remains largely ROFR-based and incumbent-led.

Sources: : Aurora Energy Research, FERC, CAISO, PJM, MISO, SPP, Texas State Legislature

FERC Order No. 1000 established competitive regional transmission across FERC-jurisdictional U.S. markets

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No. 1000 sought to improve regional transmission planning and increase competition by reforming planning, cost allocation, and developer eligibility across FERC-jurisdictional regions, including PJM, MISO, SPP, CAISO, NYISO, and ISO-NE.

1 Regulation | What FERC Order No. 1000 requires?

- **Regional planning:** Transmission providers must participate in regional planning and evaluate transmission needs and potential solutions on a regional basis.
- **Non-incumbent participation:** Removes the federal ROFR for certain transmission facilities selected in regional plans for cost allocation, allowing non-incumbent developers to compete with incumbents.
- **Cost allocation:** Requires regional and interregional methodologies for allocating transmission costs, with costs generally tied to project beneficiaries.

2 Criteria | What qualifies for competition

- **Project eligibility:** Applies to eligible facilities selected through the regional transmission planning process for purposes of regional cost allocation.
- **Developer qualification:** Regions establish non-discriminatory qualification criteria for incumbents and non-incumbents, including the financial resources and technical expertise needed to develop, construct, own, operate and maintain transmission projects.
- **Regional variation:** Each RTO/ISO tariff ultimately determines which projects are eligible and how developers qualify.

3 In Practice | Competitive transmission process

1. **Need identified**
   RTO/ISO planning process identifies a regional need.
2. **Eligibility screened**
   Project meets the region's qualification and cost-allocation rules.
3. **Solicitation opened**
   Qualified incumbent and non-incumbent developers submit solutions.
4. **Proposal selected**
   Proposals are evaluated on cost, technical merit, schedule, and execution.

Track Record | Competitive transmission today

- ~19 competitively developed projects have entered service across U.S. RTO/ISO markets.
- Additional projects remain in solicitation or development, with competitive procurement continuing across major markets.
- MISO alone has 7 competitive projects in its LRTP Tranche 2.1 portfolio; developers had been selected for five as of May 2026.

Sources: Aurora Energy Research, FERC

The main competitive models are "Procurement", where developers bid on the same project, and "Sponsorship", where they propose their own projects

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1 *Procurement model*

- **Definition:**
  - The exact project (e.g., new lines, substations, etc. to be built) decided by ISO, not by developers proposing to build it.
  - After a project is chosen by ISO, developers then bid to build it via a competitive proposal.
  - The ISO then assigns the project to the developer that is best for building the project, considering cost, timing, and quality of work.
- **Markets:** SPP Powering Progress, MISO, CAISO
- **Example:** Sooner-Wekiwa (SPP)
  - SPP identified need to build 345kV line between Sooner and Wekiwa substations.
  - 10 developers proposed to build the project; SPP chose Transource Energy.

2 *Sponsorship model*

- **Definition:**
  - Developers propose customized projects to meet generic needs identified by ISO. They can propose building any line, substation, or other grid component that meets this need.
  - The ISO then awards a developer the right to build their proposed project. Ideally, this project meets the need effectively and efficiently, given cost and duration.
- **Markets:** pjm, New York ISO Independent System Operator
- **Example:** Artificial Island (PJM)
  - PJM identified need to improve system performance in area of Hope Creek and Salem nuclear plants in New Jersey.
  - Winning developer LS Power proposed to build line under Delaware River to connect system to Delaware.

Sources: Aurora Energy Research, SPP, MISO, CAISO, NYISO, PJM

In Texas[1], incumbent utilities and ERCOT propose transmission development; only incumbent utilities may current build projects due to ROFR[2] policy

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Planning and Approval

Regional Transmission Plan

ERCOT identifies transmission needs through the RTP[3], an annual six-year planning process developed with utilities and stakeholders through the RPG[4], which evaluates both long-term and near-term transmission needs. Other market participants, usually incumbent utilities, may also propose transmission projects.

- ERCOT's RTP evaluates system reliability and economic needs over a six-year planning horizon to identify where transmission expansion may be required.
- The RTP identifies proposed transmission projects, including new lines and upgrades to existing infrastructure, needed to address projected system constraints and support future load and generation.
- ERCOT develops the RTP through the RPG[4], incorporating input from transmission service providers, utilities, and other market stakeholders. RPG also evaluates projects recommended outside of RTP process.

Project Assignment

Project assignment process: Incumbent owner model

Once approved, construction is assigned to the incumbent transmission owner serving the project endpoints.

- ERCOT determines the transmission needs and evaluates the proposed solutions.
- The incumbent transmission owner is responsible for developing, permitting, financing, constructing, and operating.
- Texas's ROFR framework limits competitive procurement, with CREZ as the exception.
- Limited competitive procurement vs. most other U.S. electricity markets

Why it Matters Now

Rapid load growth challenges the status quo

ERCOT's transmission investment needs are accelerating as demand surges from data centers, electrification, oil & gas, hydrogen, and other large loads.

- Transmission capex is stepping up sharply to keep pace with new large loads.
- ERCOT has widened its planning scope, but the development framework is unchanged.
- The scale of future transmission investment has brought increased focus to the existing transmission development framework.

1) On referring to policy within ERCOT territory of Texas, which serves ~90% of the state. 2) ROFR: Right of First Refusal. 3) Regional Transmission Plan . 4) Regional Planning Group.

Sources: Aurora Energy Research, PUCT

By comparing competitive and non-competitive completed projects, Aurora assessed the performance of both structures

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The analysis compares competitive and non-competitive projects using a consistent three-step screening framework across all U.S. markets.

1 Define project type

Definitions

Competitive: developer selected through a formal solicitation:
- Incumbents and new entrants may participate
- ERCOT CREZ new-entrant projects treated as competitive examples

Non-competitive: project assigned directly to incumbent owner:
- No competitive bidding process
- Traditional transmission development model

2 Measure outcomes

KPIs

Cost / mile
construction efficiency

Cost escalation
budget performance

Duration
delivery speed

Delay / variance
schedule performance

3 Control for comparability

Selection controls

- ✓ High-voltage facilities
- ✓ Greenfield new-build lines
- ✓ Similar project vintage
- ✓ Comparable terrain / complexity
- ✓ Representative U.S. market sample

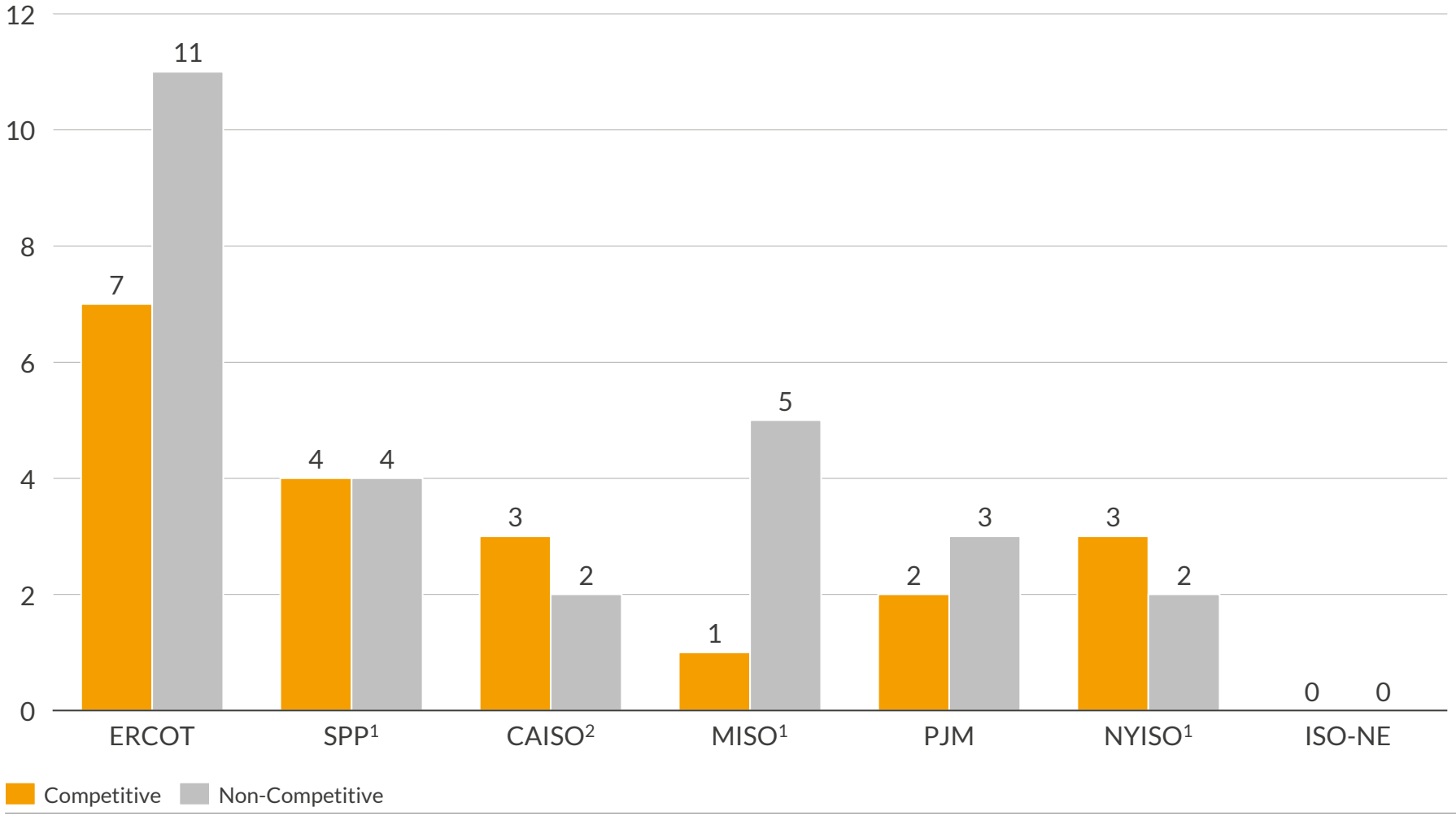
Aurora evaluated projects using common cost and schedule metrics while controlling for scope, terrain, voltage class, and development characteristics.

Sources: Aurora Energy Research, PUCT, FERC, SPP, MISO, CAISO, ERCOT, NYISO, PJM

Aurora has analyzed 47 representative competitive and non-competitive completed transmission projects across U.S. markets

Completed transmission projects analyzed by Aurora

Project count



1) All completed competitive projects in this market included in Aurora's analysis. 2) Difficulties finding project-specific final-cost data for incumbent projects is why we chose not to study any non-competitive CAISO projects. 3) To-date, the Competitive Renewable Energy Zones (CREZ) Transmission Project (which itself consists of multiple projects), completed in 2014, is the only example of competitive transmission in ERCOT. 4) ERCOT is the only U.S. market not subject to FERC Order 1000. Source: Aurora Energy Research

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The Aurora Team has conducted an extensive review of historic transmission data:

- Non-competitive projects were selected to reflect the range of transmission investments historically eligible for competitive solicitation under FERC Order 1000, providing a representative basis for evaluating competitive versus non-competitive outcomes across U.S. markets.[4]
- Projects are benchmarked using common cost, schedule, and delivery metrics to enable consistent cross-market comparisons.
- The study is designed to identify where competitive procurement creates measurable value and where results remain market- or project-specific.
- Interim results point to an emerging competitive transmission story, with early evidence of both cost and schedule advantages.

Competitive and non-competitive projects were selected to obtain a representative and comparable sample across lengths, terrain, and voltage

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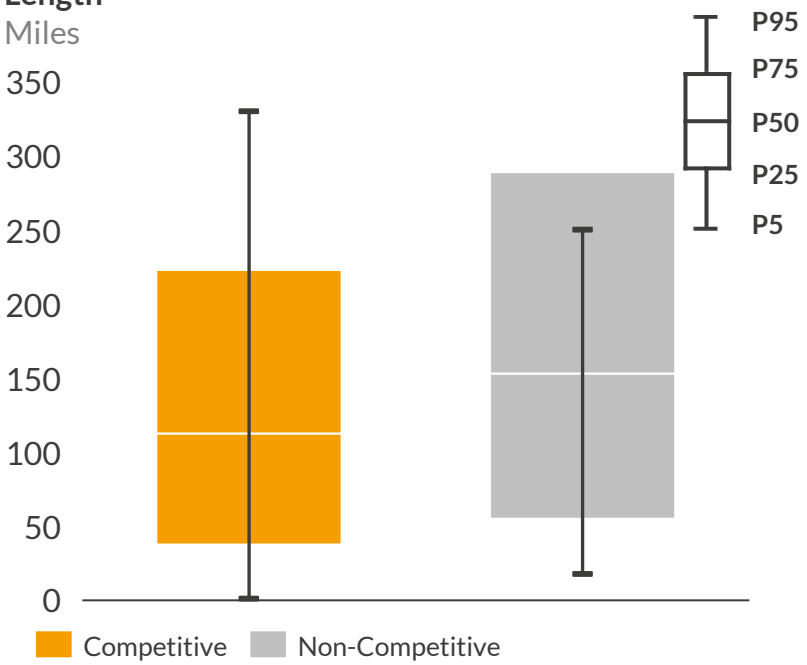
1 Competitive projects are on-average shorter than non-competitive projects

Length

Miles

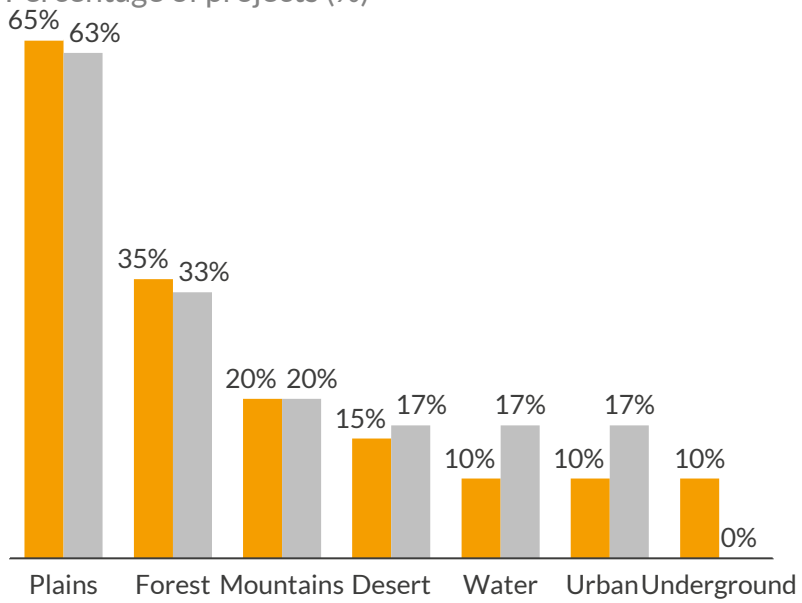


- The distribution of competitive project lengths gives shorter lengths overall than the non-competitive distribution.
- Despite the requirement for competitive projects in FERC to have region-wide benefits, state ROFR laws drive the average competitive project length down.

2 Projects cross a variety of terrains regardless of type

Project terrain

Percentage of projects (%)[1]

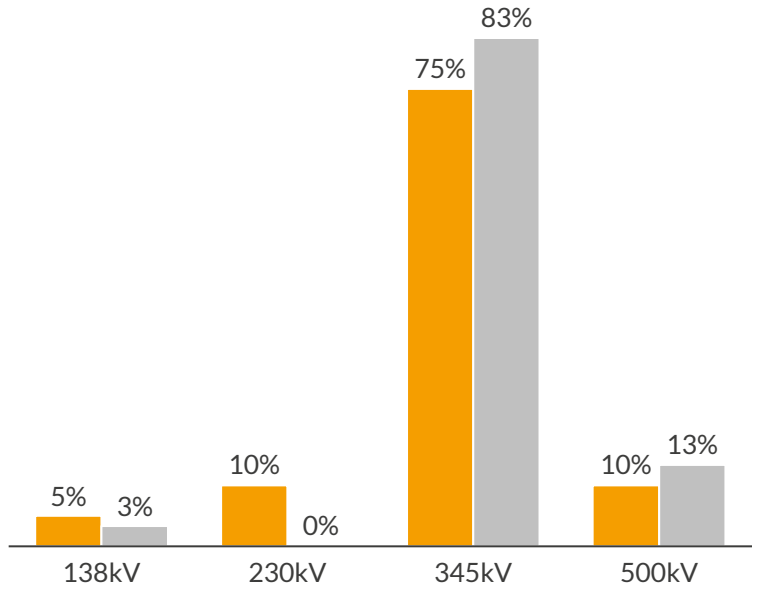


- Most projects in SPP, MISO, and ERCOT fall into the "Plains" category, whereas "Mountains" and "Desert" are present frequently in CAISO projects.
- "Mountains" and "Underground" projects are more difficult to build, exhibiting higher costs-per-mile than "Plains" and "Desert" projects.

3 Most projects studied are 345kV, regardless of type

Project voltages

Percentage of projects (%)



- Most competitive projects are 345kV; thus, most non-competitive projects chosen for study are also 345kV.
- Only two 500kV completed competitive projects exist, both in CAISO.

1) Percentages across a project type can sum to above 100%, because projects that cross multiple terrains are counted multiple times.

Sources: Aurora Energy Research, FERC, ERCOT, SPP, MISO, CAISO, ERCOT, NYISO, PJM

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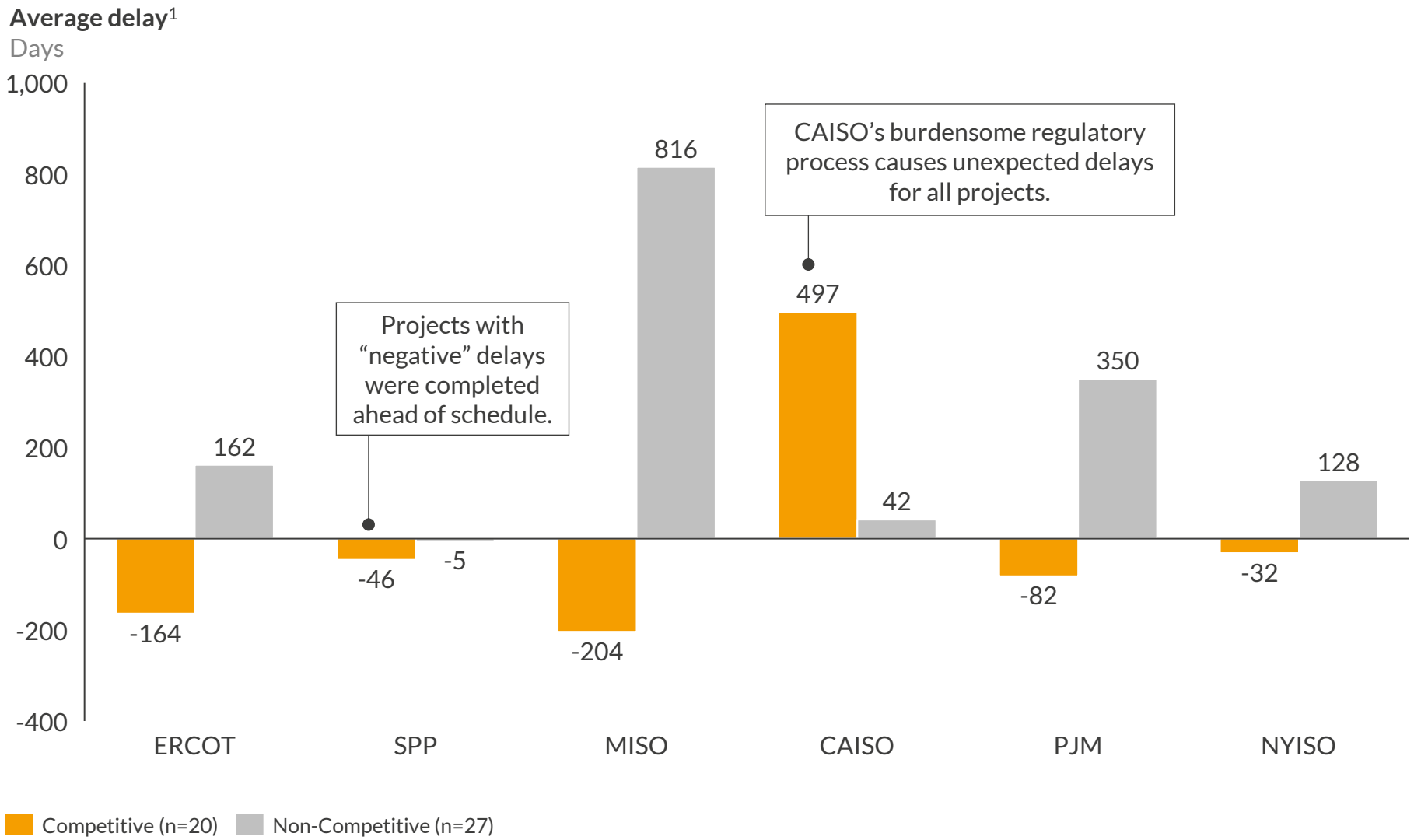
Competitive transmission projects have stayed on schedule across most markets, while non-competitive projects tend to face delays



1) Delays are defined as the difference between a project's actual in-service date and initially promised in-service date.

Sources: Aurora Energy Research, PUCT, FERC, SPP, MISO, CAISO, PJM, NYISO

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The average competitive projects have finished ahead of schedule in 5 of 6 markets

- Although unforeseeable delays can occur, non-competitive projects have been consistently delayed in nearly every market, as there are limited incentives to ensure proposed in-service dates are met.
- Meanwhile, competitive solicitation processes incentivize developers to complete projects on-time in order to win future projects. Some developers even commit to a Return on Equity (ROE) deduction punishment if their project is delayed to secure winning bids.

Competition has improved reporting and accountability when delays happen

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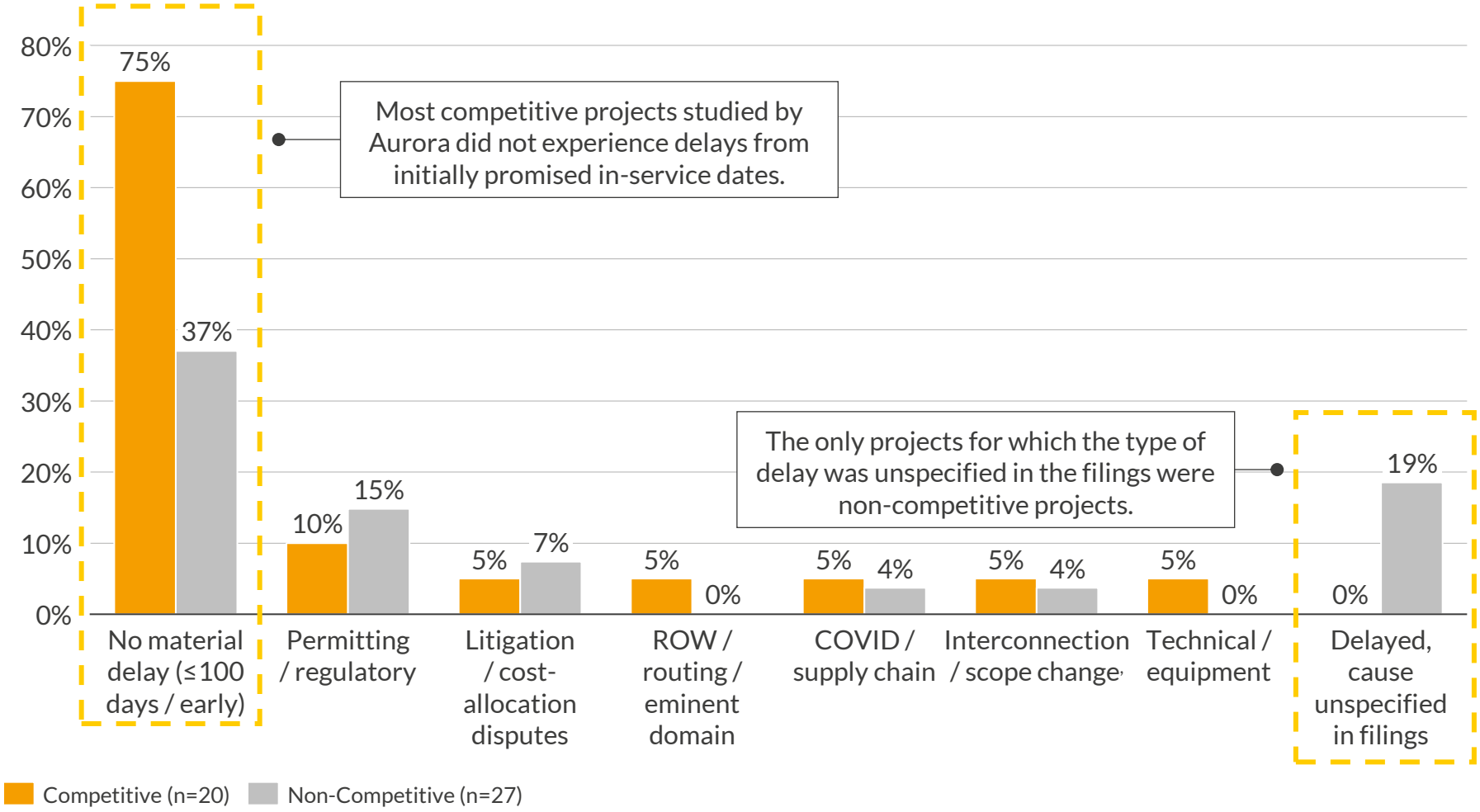
Delay attributions
Percentage of projects (%)[1]



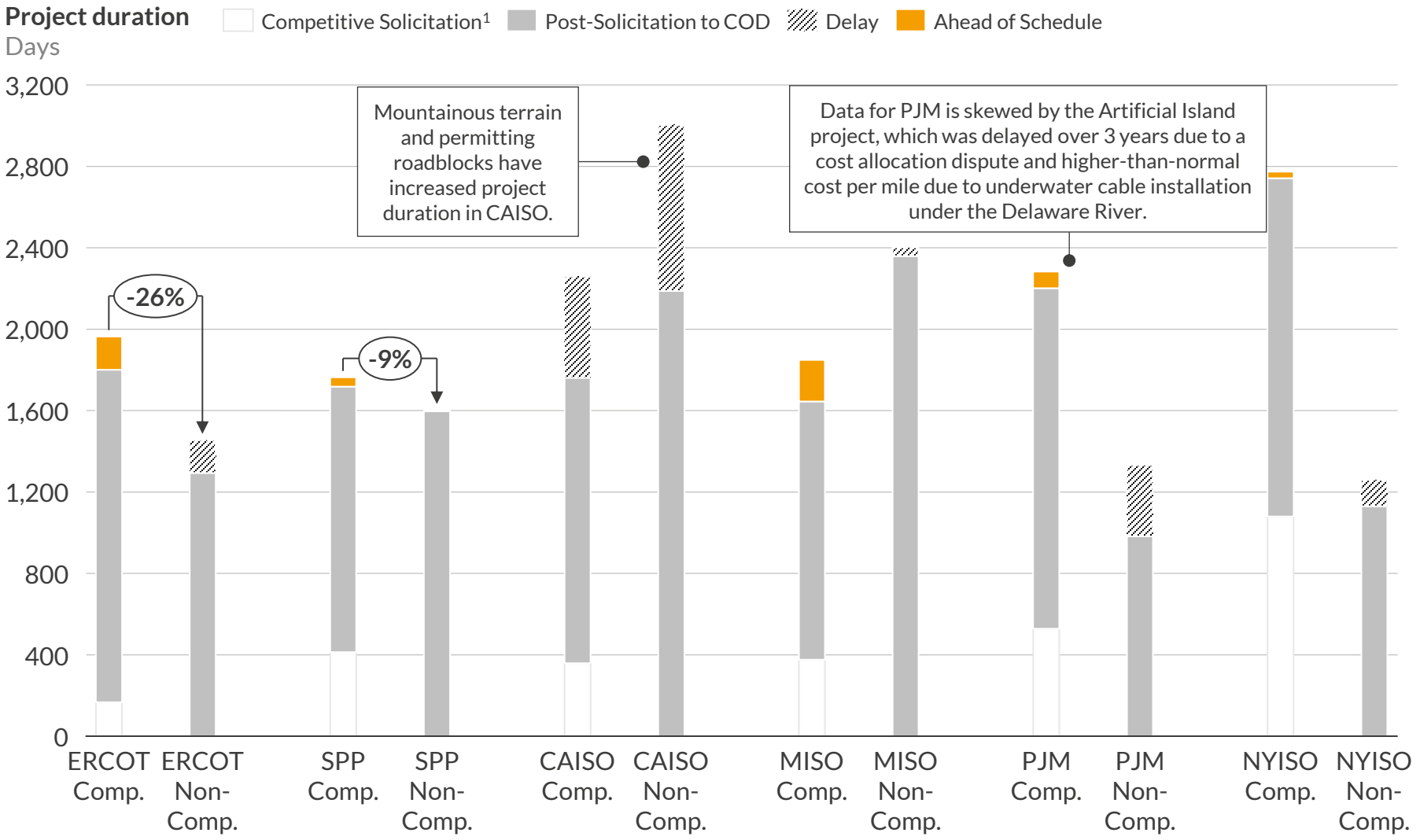
1) Projects assigned to any number of delay attribution categories. The same project can appear on multiple categories. Category types are non exhaustive.

Sources: Aurora Energy Research, PUCT, FERC, SPP, MISO, CAISO, ERCOT, NYISO, PJM

- **75% of competitive projects (15 of 20) had no material delay** vs. 37% of built non-competitive projects (10 of 27)**, the single most decisive gap in studied metrics.**
- When competitive projects did slip, causes were external and documented (**permitting, cost-allocation disputes, routing, COVID) and were not construction underperformance.**
- **5 of 27 delayed non-competitive projects reported no cause for delay in public filings, a real transparency gap compared to competitive projects**.

Time added by competitive solicitation contributes to competitive projects taking longer than non-competitive projects in 4 of 6 markets

Project duration
Days



1) Competitive solicitation is defined as the time between a need being identified and the developer being selected to meet the need. In this time, the ISO solicits proposals from developers and considers which proposal to move forward with.
Sources: Aurora Energy Research, PUCT, FERC, SPP, MISO, CAISO, NYISO, PJM

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- For all markets with competitive and non-competitive projects analyzed, **total project duration has been greater, on average, for competitive projects than non-competitive counterparts**.
- **NYISO** is the most striking example, in which competitive projects have taken 4 years longer than non-competitive projects.
- However, **MISO competitive projects** have been completed 3.4 years earlier, on average, than non-competitive projects. **CAISO competitive projects** have been completed 2 years earlier, on average.
- **SPP sees the most parity** in duration, suggesting that although a speedup in construction time occurred in competitive projects, the speedup was offset by the time spent in competitive solicitation.

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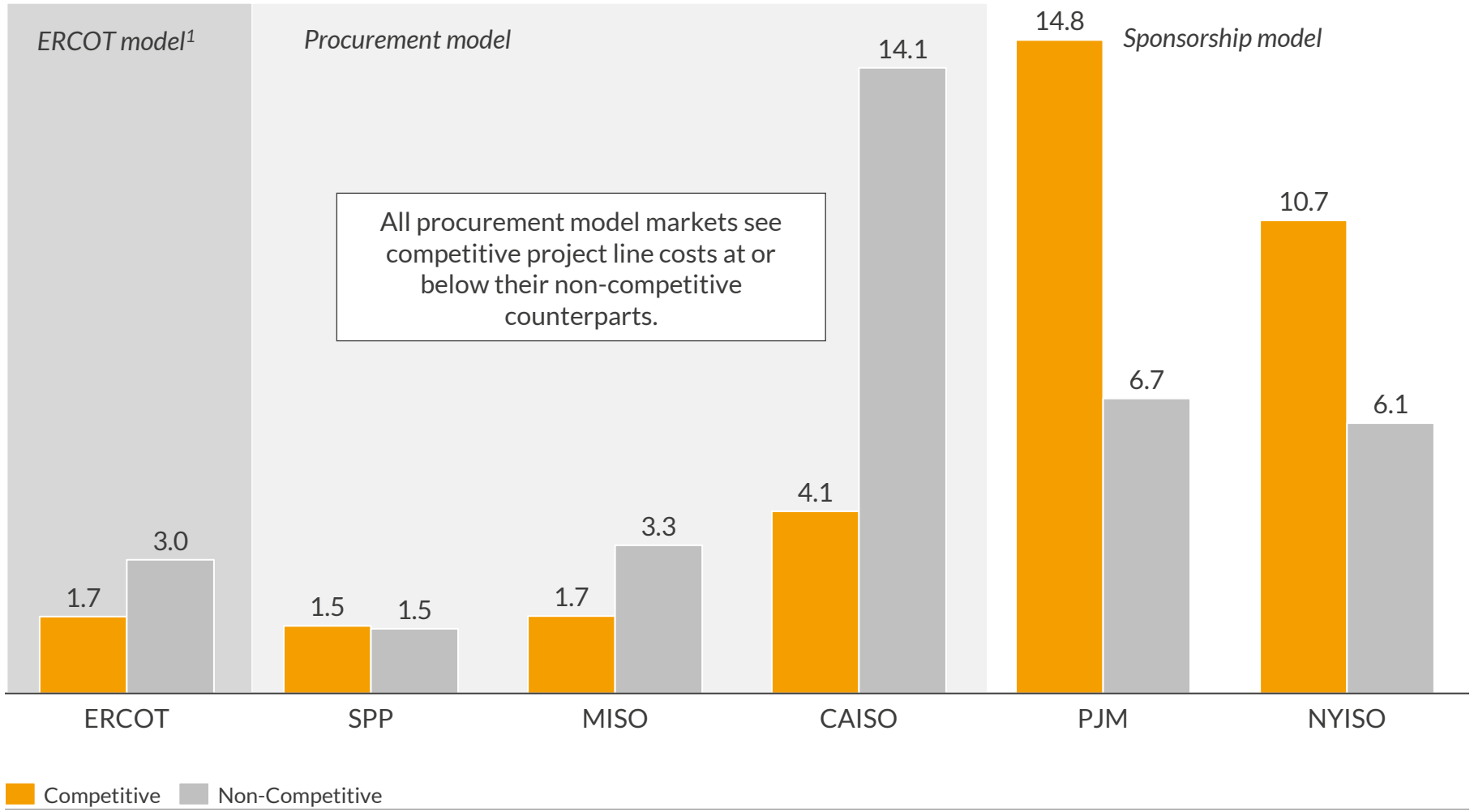
Competition has often lowered line per-mile costs, but outcomes depend on market design and local policy frameworks

Line cost per-mile
$ mn/mile (2025 real)



1) While ERCOT is not a competitive market, the CREZ new entrant developers followed a procurement model to win construction rights. Developers submitted proposals to build lines already selected for construction by the PUCT and ERCOT.
Sources: Aurora Energy Research, FERC, PUCT, SPP, MISO, CAISO, ERCOT, NYISO, PJM

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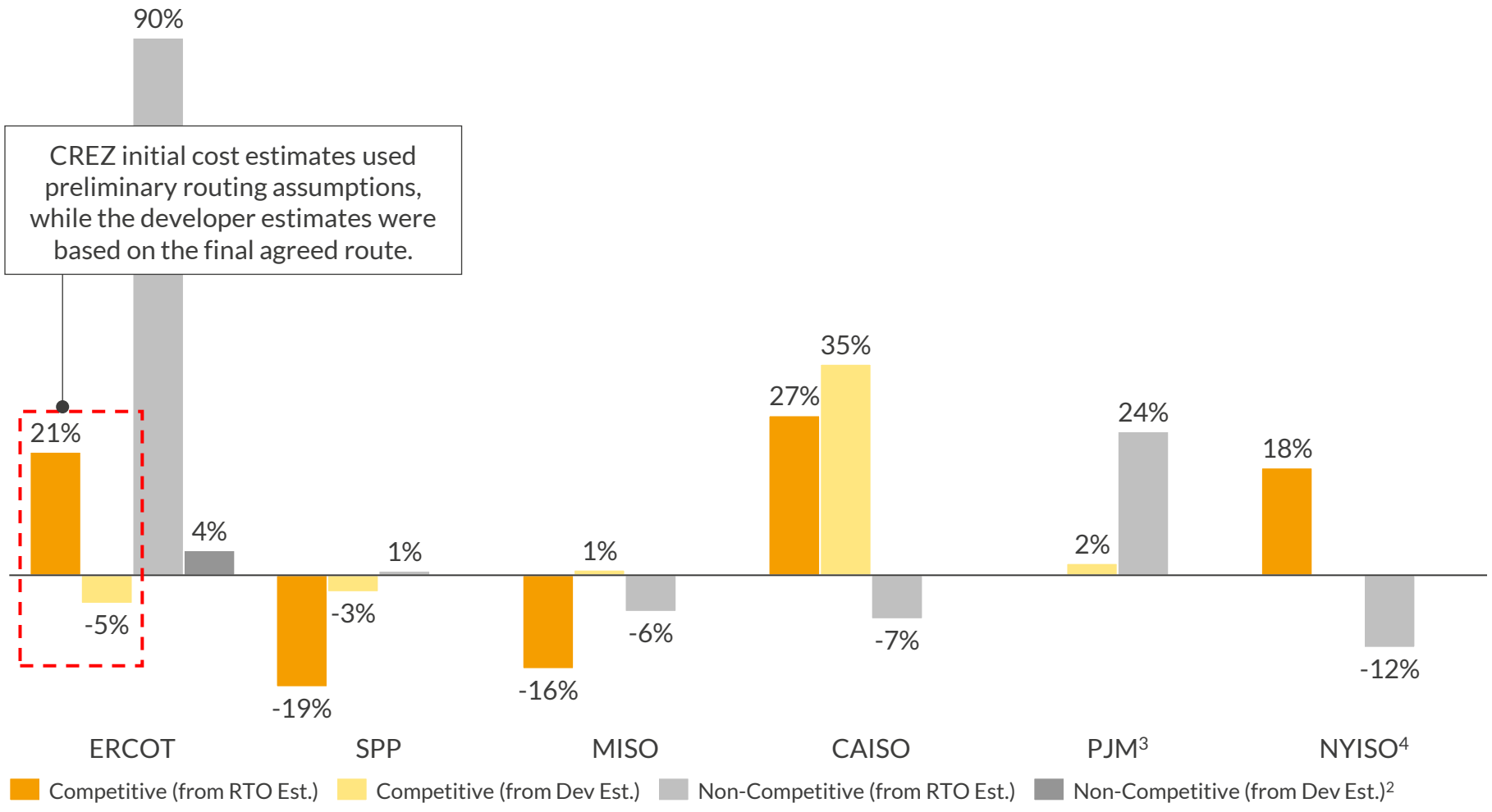
Competitive projects have demonstrated the ability to build with lower line costs when done using the procurement model

- The average cost of a mile of a greenfield line in MISO, CAISO, and ERCOT was lower among competitive projects. In SPP, competition did not meaningfully change the cost. These markets use the procurement-model, in which potential developers of competitive projects strive to offer minimized costs to win bids.
- Meanwhile, PJM and NYISO have seen higher line costs among competitive projects. These markets' sponsorship model may play a factor, since competitors suggest different projects to meet a need, rather than competing on lowering costs for the exact project.

In 3 of 6 markets, competitive projects were more successful at staying on or under-budget

Average project cost escalation, initial to final cost[1]

%



1) Total project cost used, including any substations or other grid components. Final cost is the gross plant in-service cost of the project reported after energization. Aurora is tracking only the initial cost estimates from the RTO and the developer as well as the final cost. 2) Only the CREZ incumbent projects are included in the initial developer estimate for ERCOT. 3) No RTO estimates found for PJM competitive projects. 4) No developer estimates found for NYISO competitive projects. Sources: Aurora Energy Research, FERC, PUCT, SPP, MISO, CAISO, ERCOT, NYISO, PJM

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Competitive developers adhere to their initial cost estimates in SPP, MISO, and ERCOT

- SPP has shown the best cost outcomes from introducing competitive processes. The final costs were on average 19% lower than the RTO estimate, and 3% lower than the winning developer's estimate.
- CAISO has seen the highest cost escalations among competitive projects, driven by major route changes and multi-year permitting delays.
- The RTO estimates for CREZ project costs were based on straight-line distances between substations. Thus, the 21% cost escalation stems from inaccurate initial RTO estimates.
- Among competitively procured ERCOT CREZ projects, final costs came in 5% below developer estimates.

Terrain is a complicating factor when analyzing project performance, impacting total and per-mile costs, making direct comparison difficult

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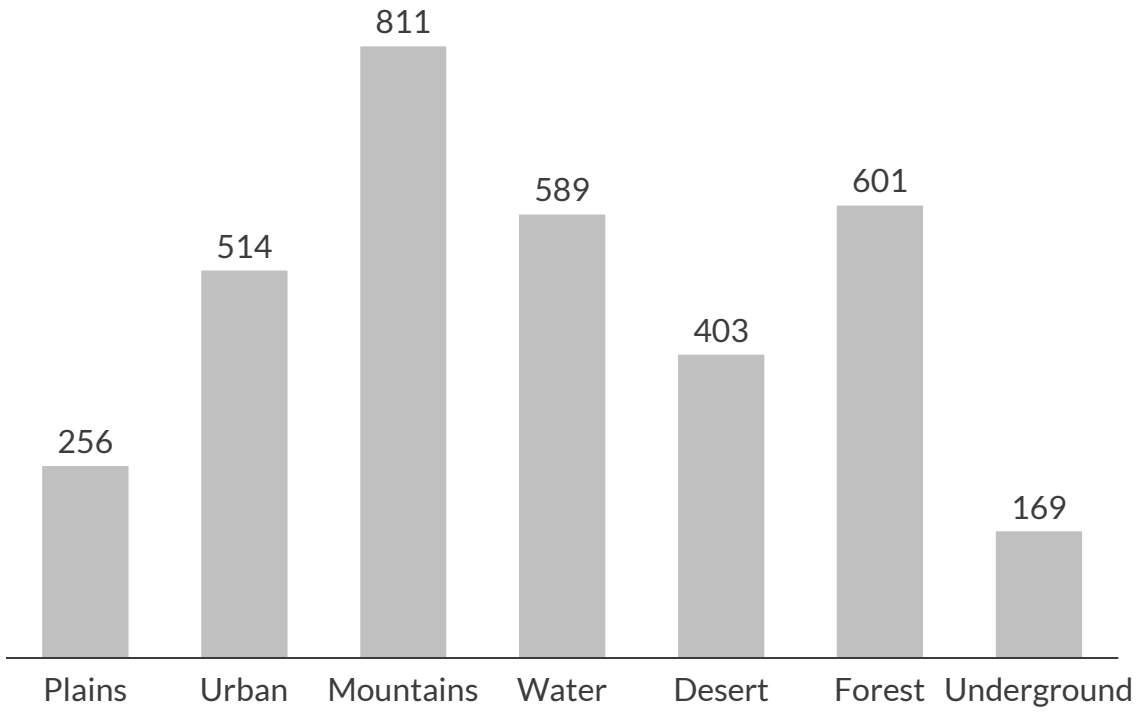
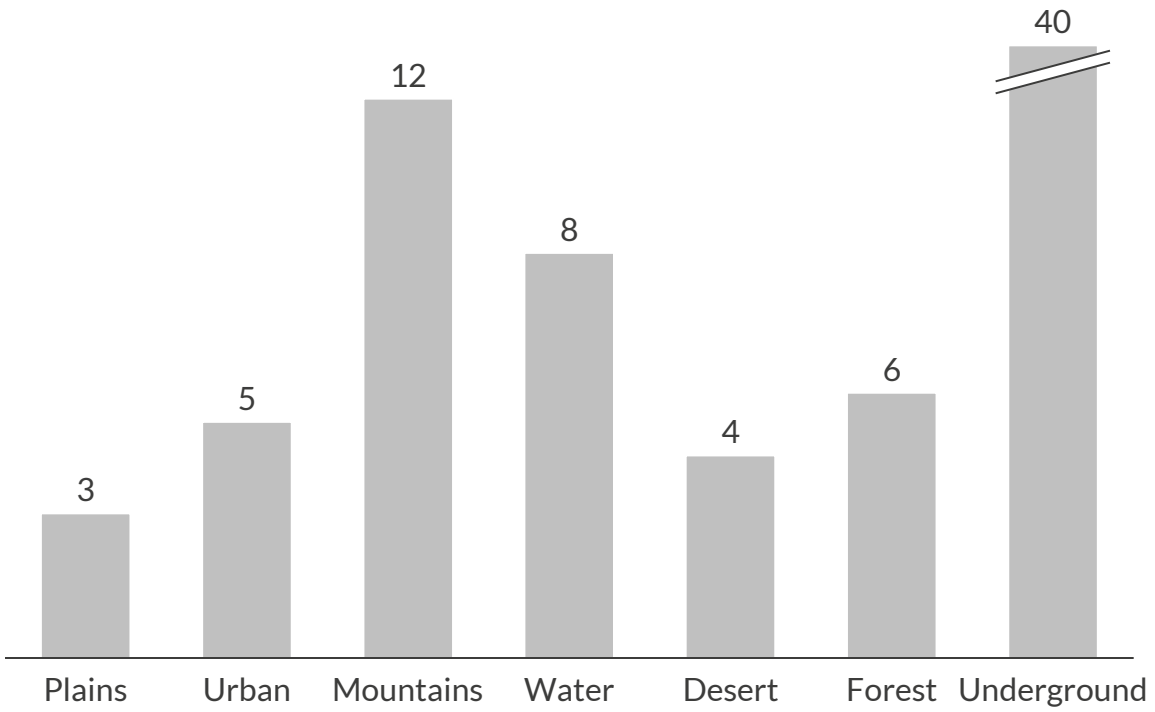
Total project cost
$mn (2025 real)



- Projects in the mountains have seen the highest average costs of any terrain. Building towers on steep, hard-to-reach slopes drives up costs and slows work progress.
- Underground projects have seen the lowest average total costs, which is primarily due to these projects' short lengths, biasing the results.

Line project cost per mile
$ mn/mile (2025 real)



- Normalizing on a per-mile basis yields similar results. However, underground projects, due to costly subterranean infrastructure, have the highest costs.
- Differing project costs across various terrain types makes direct comparison across geographies more difficult, amplifying the importance of context and transparency into processes and outcomes in evaluating competitively bid transmission projects.

Sources: Aurora Energy Research, FERC, PUCT, SPP, MISO, CAISO, ERCOT, NYISO, PJM

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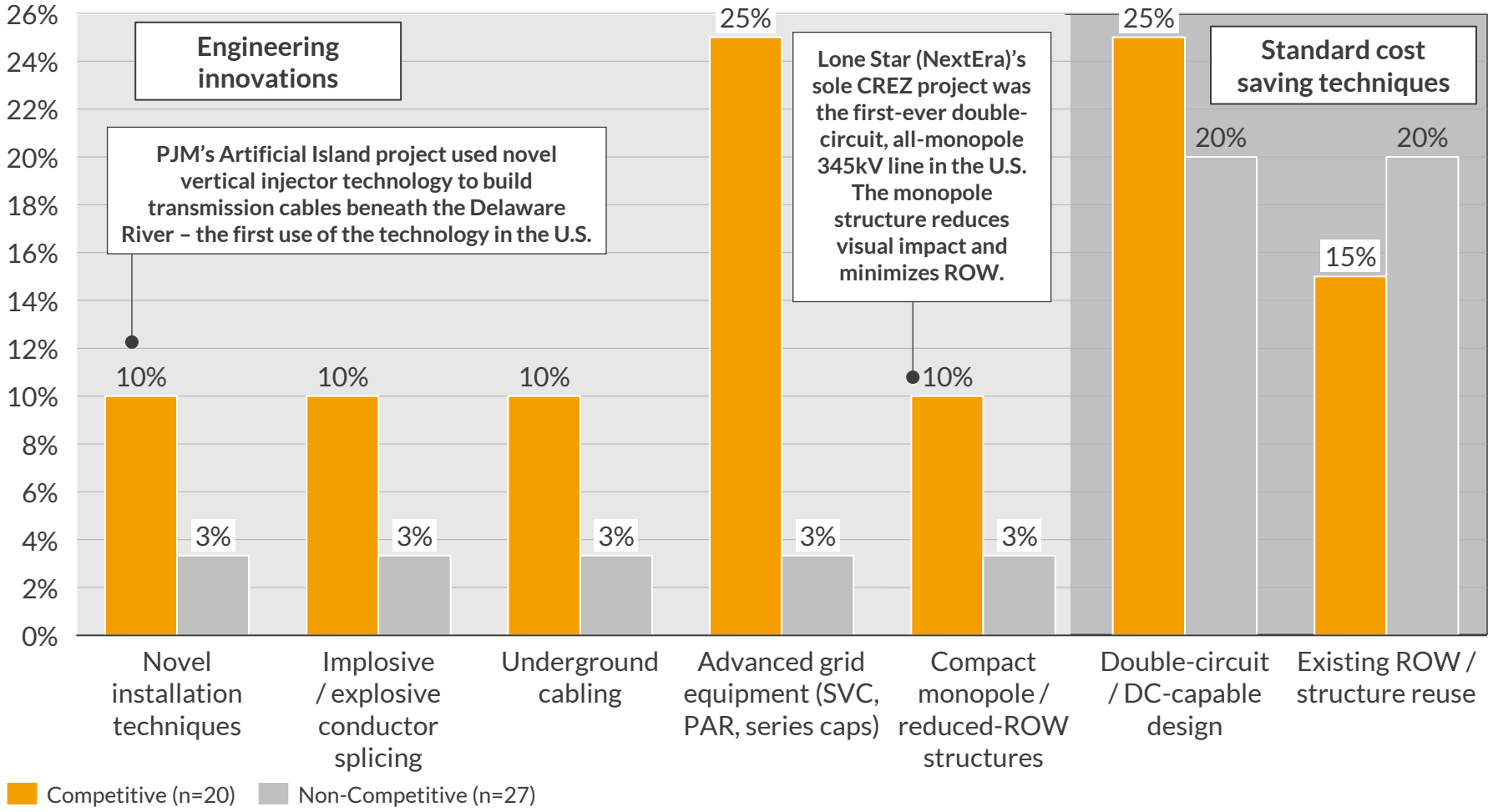
Competitive projects have been more likely to use advanced engineering and innovative techniques compared to non-competitive

Project design and construction innovations
Percentage of projects (%)[1]



1) Projects are assigned to any number of innovation categories. Some projects studied did not exhibit any innovations.

Sources: Aurora Energy Research, PUCT, FERC, SPP, MISO, CAISO, ERCOT, NYISO, PJM

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- Competitive projects have exhibited a **higher frequency of engineering innovations**, such as more novel conductor splicing, underground cabling, and never-before-seen designs and installation in the U.S..
- Non-competitive project developers, meanwhile, leverage their advantages:
  - They utilize **already-acquired Right-of-Way (ROW)** to minimize land acquisition, cutting costs and lowering the risk of court challenges.
  - Their cables cross through existing double-circuit-capable towers**, reducing the number of new towers that need to be constructed.**

Notable engineering innovations related to tower and cable infrastructure were developed across several studied competitive projects

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Innovations Underground routing technology, compact structures, and advanced conductor installation were side effects of competitively procured projects across markets.

Artificial Island - PJM

Underground delivery

Developer	Silver Run Electric (LS Power)
Innovation	Vertical injector technology for a 6-mile underground cable beneath the Delaware River.
Roadblocks	Cost allocation dispute; project suspension and early operational issue

Central A-Central C-Sam Switch-Navarro - ERCOT

Structure design

Developer	Lone Star Transmission (NextEra)
Innovation	100% compact monopole 345kV line, reducing ROW needs and visual impact.
Roadblocks	No major roadblocks identified in project notes

Harry Allen-Eldorado - CAISO

Construction technique

Developer	Desert Link (LS Power)
Innovation	Implosive conductor splicing to reduce towers across mountainous, desert terrain.
Roadblocks	Route changes, regulatory delays and COVID; cost-cap exemption dispute

Sources: Aurora Energy Research, PUCT, FERC, SPP, MISO, CAISO, ERCOT, NYISO, PJM

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ERCOT's CREZ program built ~3,600 miles of transmission lines, some competitively awarded, to unlock West Texas wind power for the grid

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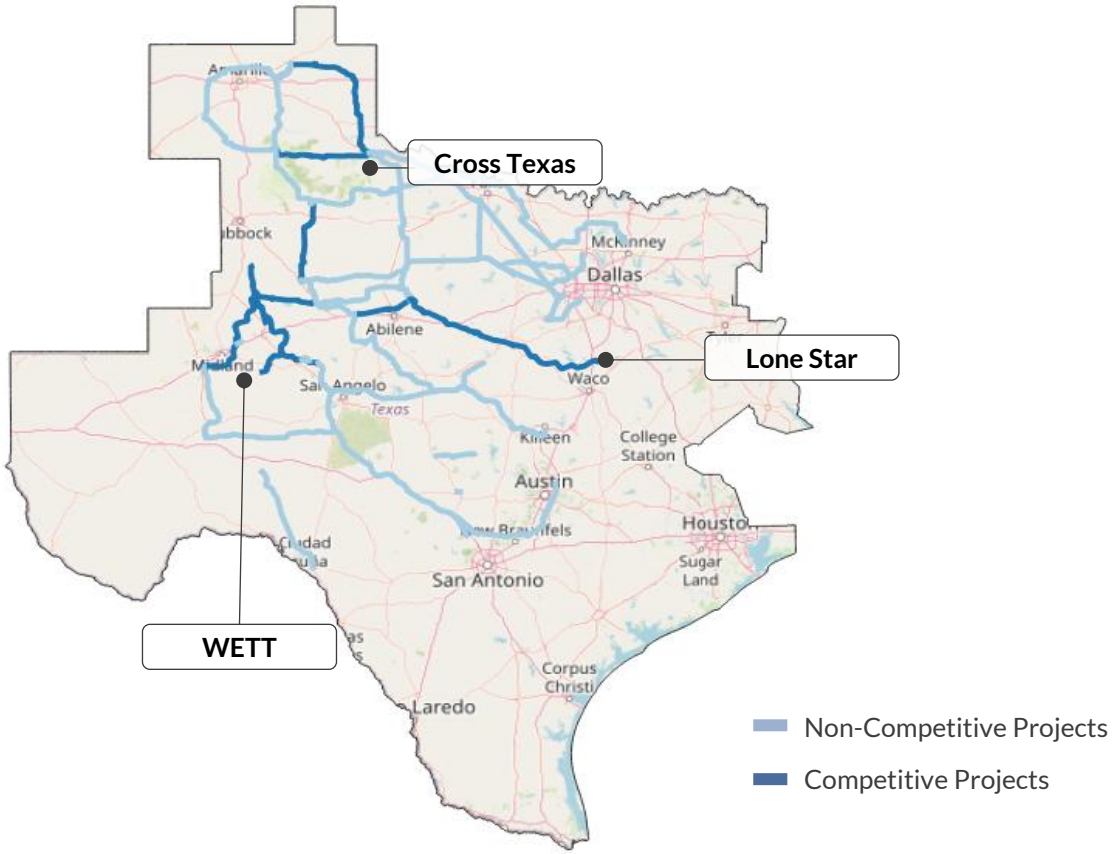
The Competitive Renewable Energy Zones (CREZ) project provides a precedent for opening transmission upgrades to competitive solicitation processes in Texas.

CREZ Projects in ERCOT



How Texas Opened Transmission Development Beyond Incumbent Utilities

1 Shifting generation

Generation moved faster than transmission buildout
West Texas offered strong wind resources, but developers needed confidence that transmission would exist while TSPs needed confidence that generation would materialize.

2 Legislative action

SB20 enabled transmission to be planned ahead of generation
The Legislature directed PUCT to designate renewable energy zones and develop the transmission needed to deliver their output to Texas customers beneficially and cost-effectively.

3 Broader participation

The PUCT selected both incumbents and new-entrant TSPs
CREZ did not use a pure lowest-price auction, but its hybrid provider-selection process introduced contestability rather than making incumbency the sole basis for project assignment.

Why it Matters Today | **CREZ outcomes demonstrate that Texas can plan for major grid needs while opening transmission development beyond incumbent utilities.**

Sources: Aurora Energy Research, Texas Legislature, ERCOT

Across CREZ transmission projects, new entrants outperformed incumbents on final cost and cost escalation, with a similar performance on schedule

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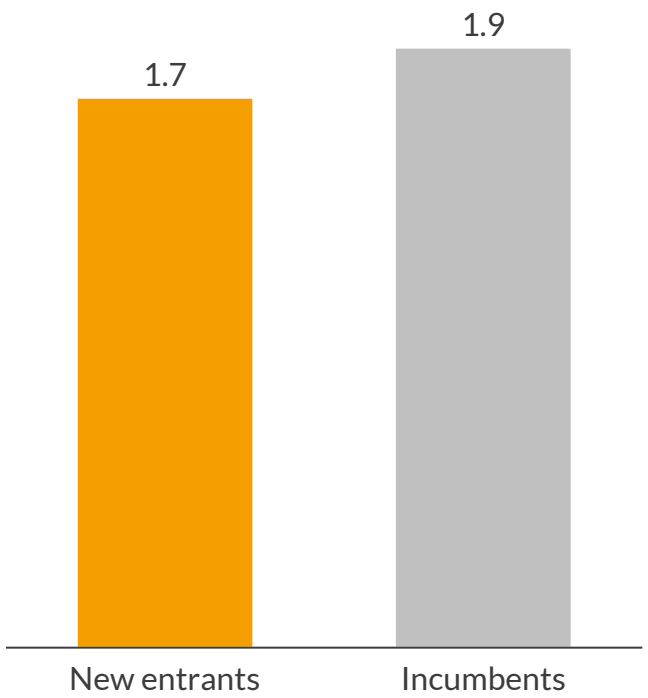
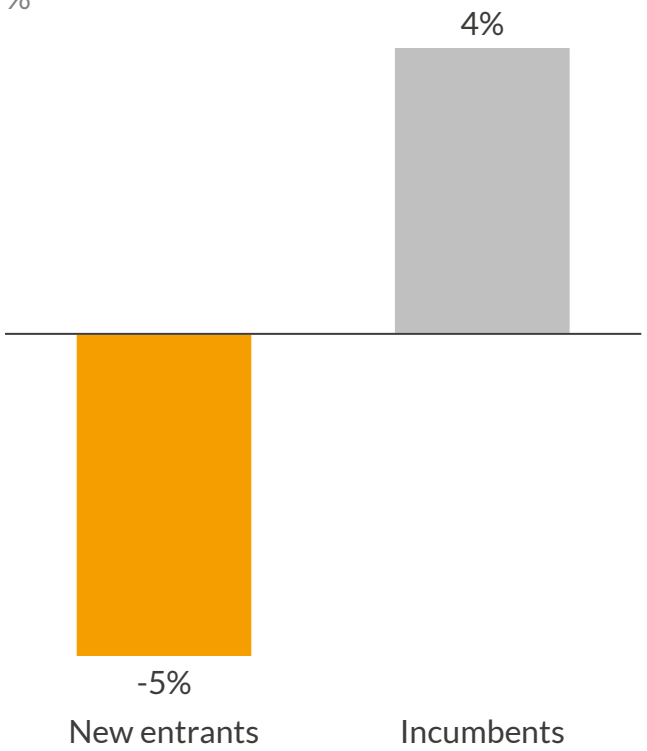
Project cost per mile, CREZ[1]
$ mn/mile (2025 real)



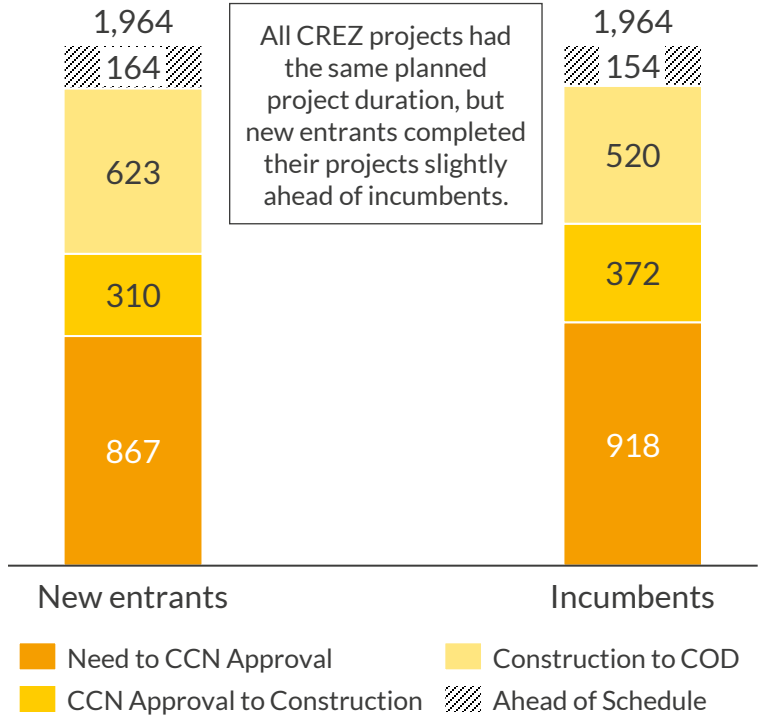
- Accounting for project scope, all CREZ projects saw relatively low costs, resulting from ERCOT's more relaxed regulatory environment and lower supply chain costs in the early 2010's.
- Nevertheless, new entrant project costs were ~$150k per-mile less, on average.

Cost escalation from initial dev. est, CREZ[2]
%



- 5 of 8 new entrant projects showed a negative cost escalation; in particular, WETT's Panhandle A D-Central B showed a 25% cost decrease.
- No incumbent projects exhibited cost de-escalation, demonstrating that incumbents have less incentive to cut costs than new entrants.

Planned and actual project duration, CREZ[3]
Days



- While nearly all CREZ projects met the scheduled completion of year-end 2013, new entrants completed projects slightly faster, despite larger scope (Lone-Star's 330-mile line[4]).
- New entrants exhibited faster CCN acquisition, despite a more burdensome regulatory process[5].

1) Line-only final cost, excluding substation costs. 2) Initial developer estimate defined as initial cost given in final CCN order. 3) Project duration defined as days between 8/15/2008 (date CREZ designated and approved) and project energization. 4) Lone Star Transmission is an indirect wholly-owned subsidiary of NextEra Energy, Inc. 5) While incumbents building CREZ projects had to merely amend their existing CCNs, new entrants had to file entirely new CCNs.

Sources: Aurora Energy Research, PUCT, ERCOT

ERCOT Case Study | As an example, Lone Star delivered the first CREZ project on schedule and 7% under its developer cost estimate

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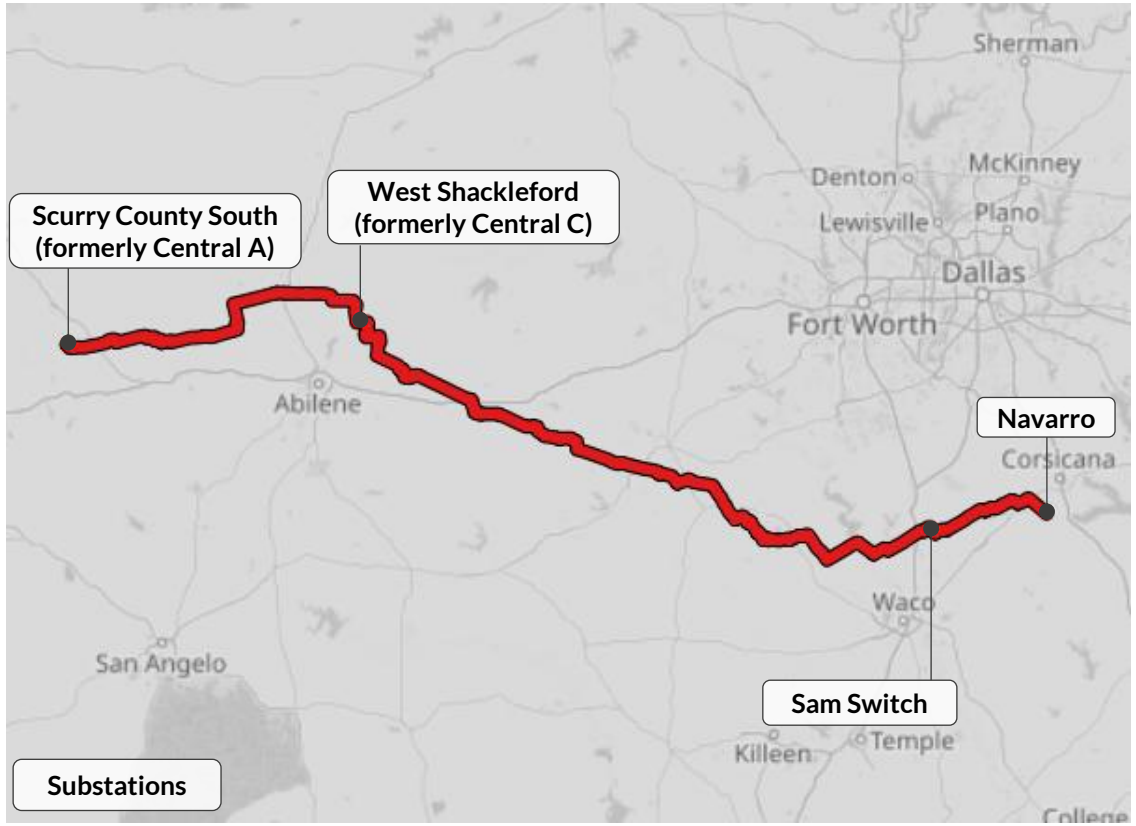
Map of Central A-Central C-Sam Switch-Navarro Line



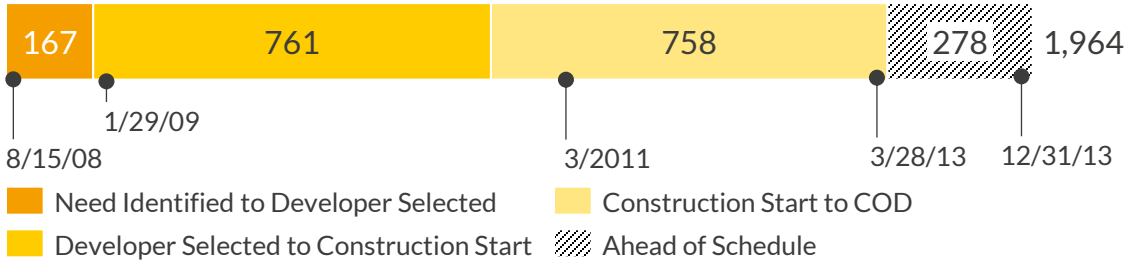
Project Scope

- 330 miles of single-circuit, double-circuit-capable 345kV greenfield line
- 2 new substations, 2 new shunt reactors

Developer: LONEstar

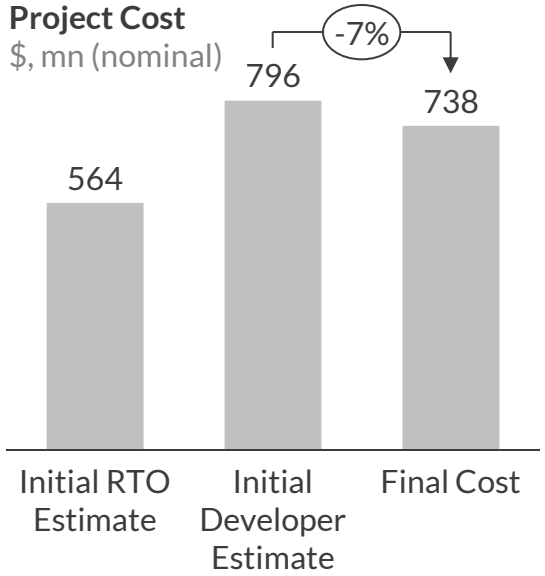
Project duration

Days



Project Cost

$, mn (nominal)



Project Context

- Part of the CREZ initiative, project designed to deliver wind power from the Central zone to eastern load centers in Texas.
- First CREZ project completed.
- First double-circuit, all-monopole 345kV line built in the U.S.
- Cost reductions from developer estimate cited due to construction contract costs, AFUDC,[1] and property taxes.

1) Allowed funds used during construction.

Sources: Aurora Energy Research, FERC, PUCT, Lone Star Transmission

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The procurement model for competitive transmission has reduced project duration and lowered average project costs

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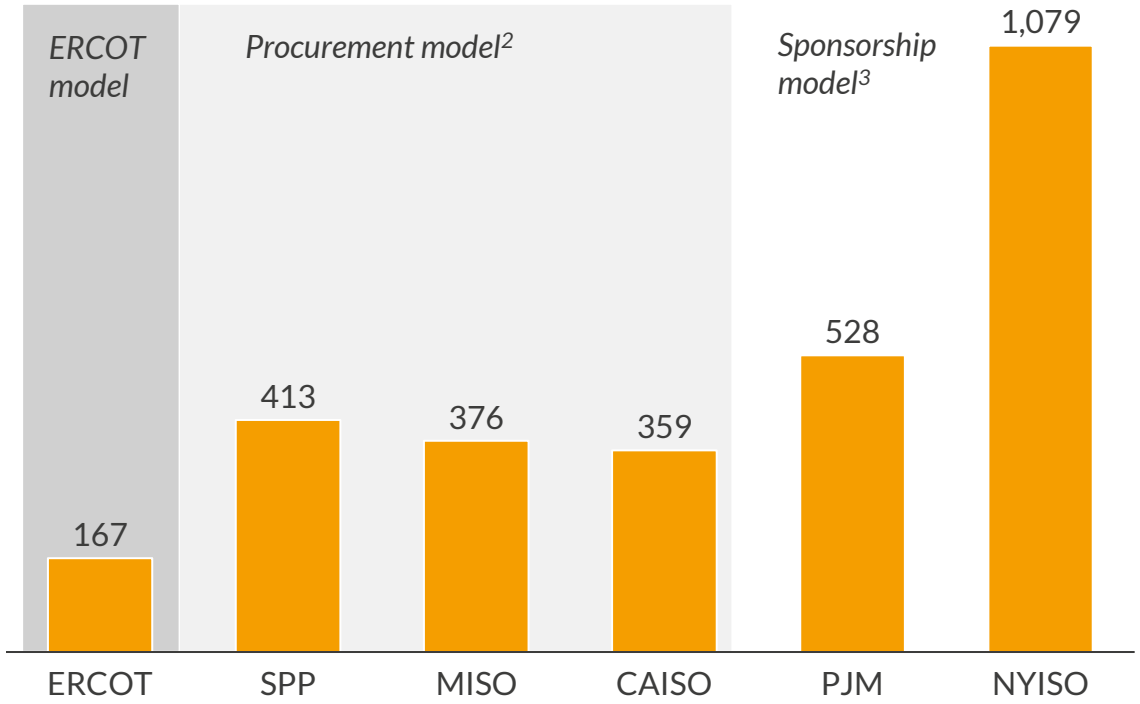
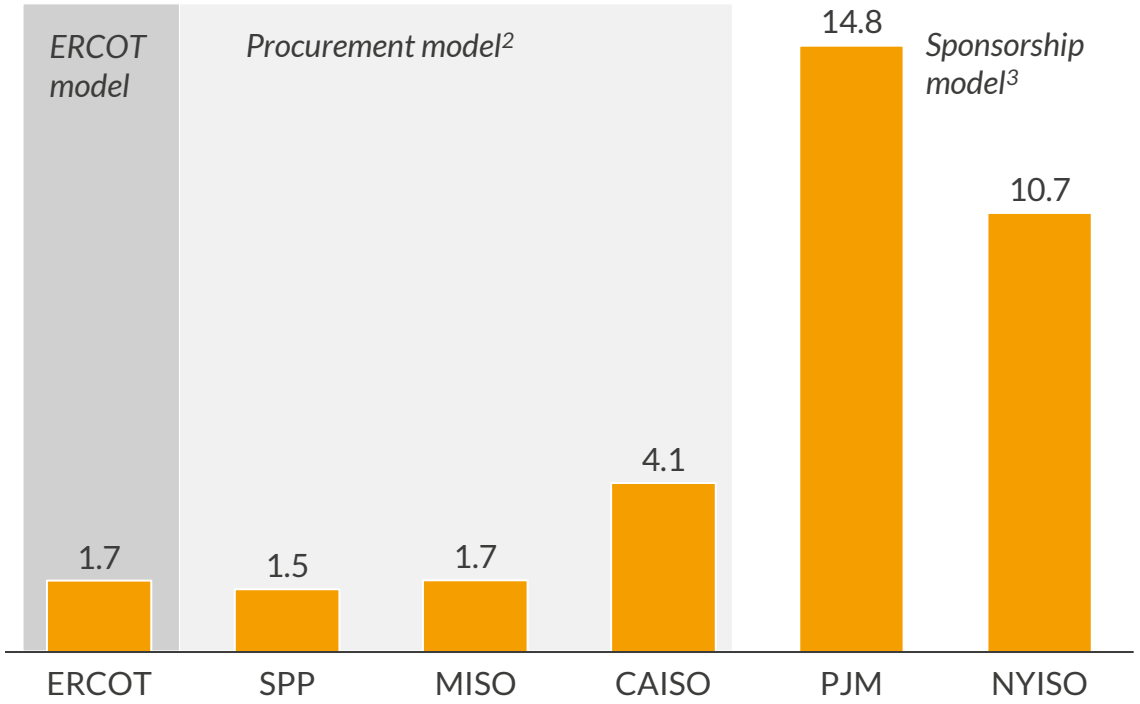
Competitive solicitation duration[1]
Days



- Competitive projects in markets with a procurement model spend less time in the solicitation phase than projects in markets with a sponsorship model.
- With a procurement solicitation process, competitive solicitations have moved faster, as there are fewer different variables among bids, simplifying RTO decision-making.

Competitive project cost per mile
$ mn/mile (2025 real)



- In a procurement model, since developers compete for the same project, there are more common elements for developers to compete on, driving further efficiency as well as incentivizing innovation.

1) Measured as time between the need identified to developer selected. 2) Procurement model for competitive transmission solicitation is defined as one where developers will bid on a pre-decided project. 3) Sponsorship model for competitive transmission solicitation is defined as one where developers will propose their own project routes meeting a more general suggested need of transmission from stakeholders.
Sources: Aurora Energy Research, PUCT, FERC, SPP, MISO, CAISO, NYISO, PJM

Winning proposals to build competitive projects often come with cost and schedule commitments, but their effectiveness varies

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Definition **Competitive contracts typically include cost containment terms, schedule commitments, and defined exceptions.**

Cost containment

- Commitment by a developer to keep their transmission project's costs within set limits, made before commencing the project.
- Common types:
  - **Hard cost cap:** no costs above this cap can be passed on to customers.
  - **Soft cost cap**: only a pre-set fraction of costs above this cap can be passed on to consumers.
  - **ROE cap:** ceiling on project's return on equity.

Schedule commitment

- Commitment by a developer to deliver a project on-time, or face punishments:
  - **ROE punishment:** developer lowers their ROE on a project if delayed from their promised COD, scaled by the length of delay.

Exceptions

- Scenarios laid out by the developer that allow them to break their commitments.
- Common types:
  - **Force majeure:** unforeseeable events, such as natural disasters
  - **Policy changes:** government-enforced adjustments to project scope
  - **AFUDC:** Allowed funds used during construction.

Examples **These examples show real cost caps, ROE caps, and schedule penalties across MISO, PJM, and SPP projects.**

Project Name	Region	Commitments
Duff-Coleman	MISO	▪ $47 million hard cost cap ▪ ROE cap at 9.8% ▪ Equity cap at 45%
Artificial Island	pjm	▪ $166.3 million cost cap, with AFUDC exception
Wolf Creek-Blackberry	SPP Powering Progress	▪ $55 million hard cost cap ▪ 1.5 basis point deduction in ROE for every month delayed from promised COD date of 1/1/26

Sources: Aurora Energy Research, FERC, T&D World

Of the 12 studied competitive projects featuring cost caps, 6 projects' final costs remained at or below the cap

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Project	Market	Hard cost cap?	Soft cost cap?	AFUDC exception?	Schedule commitment?	Final cost at or below cost cap?	On time?
Duff-Coleman[1]	MISO	✓				✓	✓
Sooner-Wekiwa[2]	SPP	✓		✓			
Wolf Creek-Blackberry	SPP	✓			✓	✓	✓
Minco-Pleasant Valley-Draper	SPP	✓			✓	✓	✓
Crossroads-Hobbs-Roadrunner	SPP	✓			✓	✓	✓
Suncrest SVC	CAISO		✓		✓	✓	
Ten West Link	CAISO	✓		✓			
Harry Allen-Eldorado	CAISO	✓		✓	✓		
Artificial Island[3]	PJM	✓				✓	
Thorofare Creek-Goff Run-Powell Mountain	PJM						✓
Empire State Line	NYISO		✓	✓			✓
Central East Connect	NYISO		✓	✓		✓	✓
New York Energy Solution	NYISO		✓	✓			✓
Central A-Central C-Sam Switch-Navarro[3]	ERCOT					✓	✓
Scurry County South-Long Draw-Grelton-Odessa[3]	ERCOT					✓	✓
Long Draw-Sand Bluff-Divide-Bearkat[3]	ERCOT						✓
Cottonwood-Dermott[3]	ERCOT					✓	✓
Gray-White Deer[3]	ERCOT						✓
Gray-Tesla[3]	ERCOT					✓	✓
Silverton-Tesla[3]	ERCOT						✓

Projects with hard cost caps finished below the cap 5 of 8 times. Without an AFUDC exception, project costs stayed under the cap 3 of 3 times.

1) Commitment details published in TDWorld article. 2) Exact cost cap details for Sooner-Wekiwa are confidential and thus unknown, but documents imply a hard cost cap with AFUDC exception. All competitive projects following Sooner-Wekiwa were required to publish commitment details. 3) Artificial Island was built by multiple developers. The portion built by Silver Run Electric did include a cost cap, which was honored. 3) No ERCOT CREZ projects included cost caps. However, the projects did give developer initial estimates found in the CCN final orders. This estimate is defined as the cost cap for ERCOT-only entries in the 2nd column from the right. Sources: Aurora Energy Research, ERCOT, MISO, PJM ,NYISO, SPP, CAISO

Hard cost caps and punishments for delays helped to ensure a competitive project stays on-time and under budget, even with the same developer

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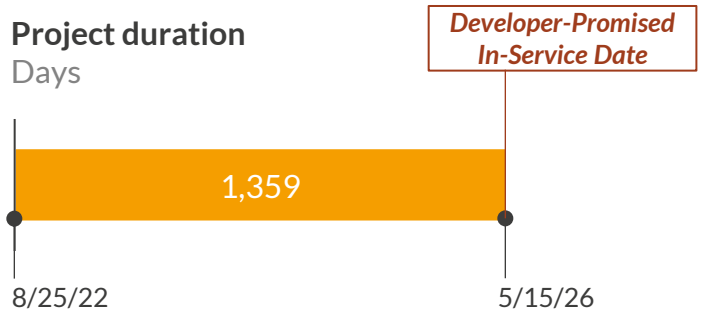
Case Study #1 Crossroads-Hobbs-Roadrunner | The developer adhered to their binding $291mn cost cap; *with no exceptions for AFUDC[1]*.

Market: SPP Powering Progress

Developer: NEXTera ENERGY TRANSMISSION

Cost Commitment Results
$mn, nominal

Project duration
Days

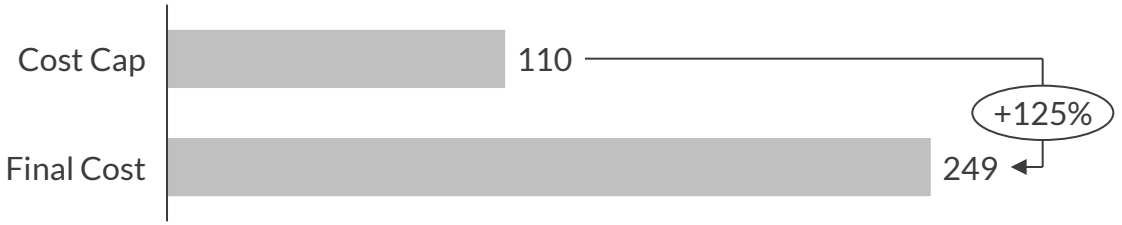


Case Study #2 Empire State Line | AFUDC[1] exceptions to the $110mn cost cap allowed the cost to consumers to increase to $249mn.[3]

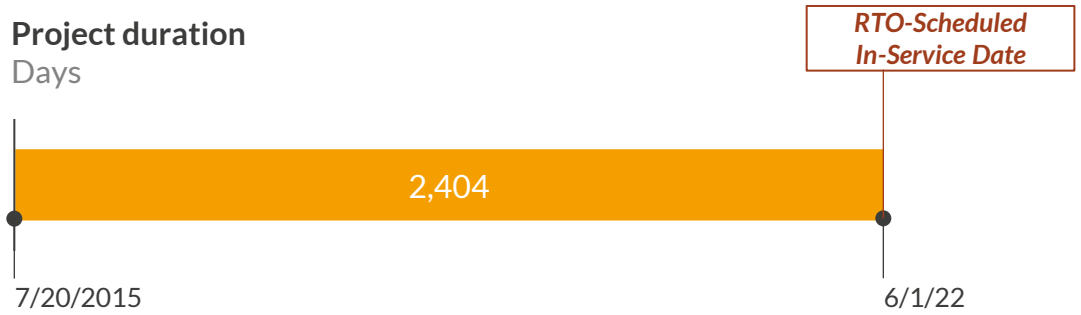
Market[2]: New York ISO Independent System Operator

Developer: NEXTera ENERGY TRANSMISSION

Cost Commitment Results
$mn, nominal



Project duration
Days



1) Allowed funds used during construction. An AFUDC exception allows increased construction costs to go into rate base. 2) NYISO mentions that cost commitments are not used in the selection criteria. 3) The IEP for this project gives a "binding cost cap" on its RRE (RFP Response Estimate) of $290.6M. However, the report notes exemptions to this cap due to government-mandated route changes, changes in project scope, and other force majeure changes.

Sources: Aurora Energy Research, NYISO, SPP

SPP uniquely discloses developer commitments and reports actual costs and schedule throughout the entire project lifetime

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The Industry Expert Panel (IEP) report, released by SPP based on a survey of industry experts at the time of competitive developer selection, clearly lays out the justification for the developer's award, as well as promised cost and schedule commitments made. *No other market publicly releases a similar report.*

Key details made public in the IEP report and future reports

1 Winning developer justification

The IEP report gives a summary of the main reasons that the developer was chosen. The proposal is scored across the following categories: Engineering Design, Project Management, Operations, Rate Analysis, and Finance.

2 Cost and schedule commitments by the developer

The report includes details on any cost caps and schedule commitments made by the developer, which may include punishments for not meeting these commitments. *While other markets do public report the existence of these commitments, only SPP publishes the details of those commitments.*

3 Intermediate and final costs

Following the IEP report, the winning developer must publish biannual cost and schedule estimates to the public, as well as final cost and schedule outcomes.

Example Project: Minco-Pleasant Valley-Draper

1

Main reasons cited for the developer's successful bid: lowest projected cost with a strong cost cap, ahead-of-schedule estimated COD made possible by a parallel construction plan, and a preferred route that avoided tribal lands with some ROW already acquired.

2

Hard cost cap on the projected CapEx, with no AFUDC[1] exemption; 9.8% ROE cap; 55% equity cap; schedule guarantee of 1/1/2025, with 1.5 basis-point ROE deduction for every month delayed beyond date.

3

Biannual reports and the final report all gave project costs at exactly the cost cap and no higher.

1) Allowance for funds used during construction.

Sources: Aurora Energy Research, SPP

To realize benefits of competitive transmission, key elements of success have appeared to be critical

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Markets with the following characteristics have shown **average savings of 19%** from the RTO estimate for a competitive project.[1]

1

"Procurement" model

Used in SPP, MISO, CAISO, and ERCOT's CREZ initiative, this model, where developers compete to win the bid on predefined projects on price, timeline, etc., demonstrates stronger competitive outcomes across metrics.

2

Binding cost caps with ROE penalties

SPP and MISO select developers that promise hard cost caps and schedule commitments, with punishments for not meeting them.

3

Regulatory transparency

By making public the winning developer's cost and schedule commitments, SPP holds the developer accountable to deliver on their commitments.

1) This number is calculated by averaging the percent change in project cost, from initial RTO estimate to final, for all completed competitive projects in SPP and MISO.

Sources: Aurora Energy Research, FERC, PUCT, SPP, MISO, CAISO, ERCOT, NYISO, PJM

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Competitive procurement on average has the potential to reduce upfront total expenditures for all unallocated STEP projects by ~$7 billion

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ERCOT-identified Non-Competitive STEP Path

~$36.43bn[1]

Incumbent path: cost-plus, no caps

- **Historical non-comp ERCOT cost escalation:** +90% on average
- **Average schedule delay vs. planned In-service date:** +162 days
- **Who bears overrun risk:** Ratepayers (both industrial and residential)
- **Transparency on delay causes:** Often absent from public filings

Potential Competitively Procured STEP Path

~$29.62bn

Competitive path: hard cap, ~19% savings assumed

- **Witt Competitive outcomes based on results in MISO and SPP : ~19% underestimate from ISO/RTO on average**
- **Schedule performance (competitive ERCOT, MISO, and SPP): On time or early**
- **Who bears overrun risk: Developer (hard cost cap can protect ratepayers)**
- **Schedule accountability: Penalties (developer loses ROE for delays)**

Upcoming STEP plan projects could provide an opportunity for applying competitive procurement processes.

1) Includes only large transmission projects yet to be allocated to TPO as of August 2026, excludes Permian Basin import lines.

Sources: Aurora Energy Research, PUCT, FERC, SPP, MISO, CAISO, ERCOT, NYISO, PJM

ERCOT's future high voltage projects are potential candidates for competitive processes, due to their high-voltage greenfield lines and interregional benefits

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1 Permian Basin Reliability Import Paths
765kV | AEP / CPS / Oncor / LCRA

~$13.8bn | ~810 mi | ISD[2]: 2029-30

Developer selection status: CCNs opened for 5 of 5 lines by incumbent utilities, and three CCNs have been approved to finalize the developers as of September 16, 2026.

Regional benefits: Sends power to the Permian Basin to meet increased demand due to oil & gas electrification.

Notes:
- $9.1bn estimate from 765kV lines and substations only, $4.7bn estimate lower-voltage grid components.
- Endorsed by ERCOT.

2 Western Loop
765kV | TSP Not yet confirmed[1]

~$0.7bn | ~161 mi | ISD[2]: 2030

Developer selection status: No developers selected and no CCNs filed.

Regional benefits: Complements the Permian Basin Reliability Plan by allowing bulk power flow across the Basin, not just to and from.

Notes:
- Standalone extension of the Permian Basin import paths, first presented in the July 2025 RPG meeting.
- Endorsed by ERCOT.
- As of September 16, 2026, no lower voltage supporting lines have been announced.

3 Eastern Backbone
765kV | TSP not yet confirmed[1]

~$20.5bn | ~1.1k mi | ISD[2]: 2030-32

Developer selection status: No developers selected and no CCNs filed.

Regional benefits: Reduce congestion and serve demand driven by population growth, electrification, and data centers in the Texas Triangle.

Notes:
- $8.1bn estimate in 2024 RTP for 765kV lines only, updated to $9.4bn estimate in 2025 RTP.
- $11.1bn estimate in 2024 RTP for lower-voltage grid components.
- Endorsed by ERCOT.

4 Central TX (Euclid-Hillje)
765kV | TSP not yet confirmed[1]

~$1.4bn[3] | ~130 mi | ISD[2]: 2031

Developer selection status: No developers selected and no CCNs filed.

Regional benefits: Relieve the constrained Central Texas import corridor from the Gulf Coast.

Notes:
- Standalone of the Eastern Backbone project, first presented in the November 2025 RPG meeting.
- Endorsed by ERCOT.
- In August 2026, ERCOT filed additional details, including a supporting 345kV line from Euclid-Misty, though cost breakdowns are not currently available.

1) Final transmission service providers for these projects have yet to be assigned by the PUCT, though ERCOT has proposed various TSPs in its endorsement of each project. 2) Stands for in-service dates. In-service dates are preliminary and pending additional market stakeholder updates, given recent developments and the suspension of Permian transmission plan CCNs. 3) Estimated cost prior to inclusion of Euclid-Misty line, though if an extra line is opened to competition, cost savings could improve.

Sources: Aurora Energy Research, ERCOT, ERCOT 2024 RTP, ERCOT 2025 RTP, PUCT

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Transmission charges, called TCRF, currently contribute up to 15% of the average ERCOT residential electricity bill[1]

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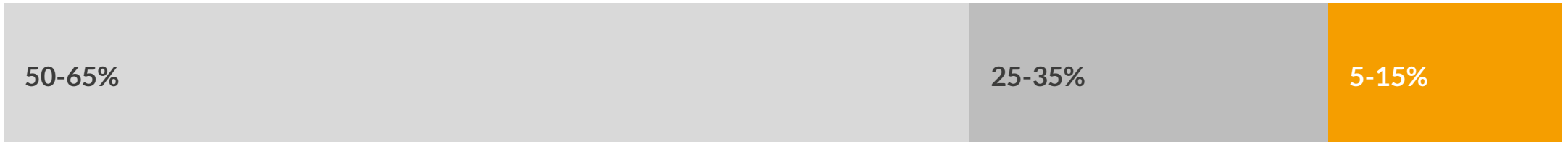
Composition of a typical residential bill at 1,000kWh/month in ERCOT[1]

Average monthly residential bill total in Texas: ~$170/month[3]



TCRF alone: ~2¢/kWh[2] (or $20/month[3])

- Transmission Cost Recovery Factor (TCRF) is a component of residential electricity bills that serves to recover new investment in transmission, based on a set revenue requirement.
- Residential ratepayers alone are not responsible for complete recovery of costs, but typically an allocation between 40-50%, shared with industrial loads as well as other load entities.

How does future investment play in?

- The STEP plan and other approved transmission investment will be partially recovered through TCRF over the next decade.
- The initial CAPEX and ongoing depreciation of transmission investment projects is included in the final charge to ratepayers.

Savings from competitive procurement on STEP projects reduce the TCRF line directly.

1) Averaged over the three largest publicly owned utilities in ERCOT as of August 2026 over the last 3 years. 2) Taken from Oncor representative energy bill. 3)Average monthly residential bill taken from EIA 861 Schedules 4A-D, EIA-861-S and EIA-861U, $2025USD real.
Sources: PUCT, Transmission and Distribution Utility Rates (August 2026); EIA, Texas Electricity Profile 2024; EIA, Electricity Data Browser

By combining potential CAPEX savings with standard utility return metrics and depreciating these savings over time, we calculate cost impacts to consumers[1,2]

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1 Benchmark Savings

- SPP and MISO projects on average: **−19%** vs RTO est.
- Avg competitive SPP schedule: **~46 days** (early delivery)

Applied savings of an assumed 18.7% capital expenditure reduction

2 Apply Savings to Project Baseline

Include STEP project costs as they are energized:

- Incumbent baseline (including all supporting lines): ~$36.4bn
- **Competitive estimate: ~$29.6bn**
- Assume projects follow latest announced ISD's; for Eastern Backbone project, spread in-service costs across 3-year ISD range

3 Calculate Retail Rate Impact

- **TCRF → rate reduction:**

ΔRevReq = ΔCAPEX × Rate of Return (RoR) (6.6%) ÷ Billing Determinant × Residential Allocation (~48%)

  - **Retail rate savings as high as 0.21 ¢/kWh (2033)**

4 Lifetime Customer Savings

- **Asset life:** 40 yrs · Discount rate (set to equal RoR)
- **STEP program:**
  - **~$16bn (real 2025) lifetime savings for all ratepayers (service territory-wide)**

5 Output: Per-Customer Annual Savings

Δ Rate (¢/kWh) × 1,000 kWh/mo × 12

- **Projected totals: up to ~$25/yr (real 2025) per average residential customer in relevant service territories**
- Savings amount to roughly 2% of the average account payer's annual bill

1) ROEs: PUCT Dkt 58306 (Oncor, Apr 2026); PUCT 2020 rate cases (AEP Texas, CenterPoint); AEP 2024 10-K; CenterPoint Sep 2025 Investor Update. 2) STEP cost estimates preliminary (ERCOT Board Dec 2025; PUCT Apr 2025). All savings estimates indicative pending final CCN filings. Residential load growth rates taken from Aurora Central Case load forecast Q3 2026. Total 5-year savings shown from 2032-2036 based on projected CAPEX schedules.

Sources: PUCT, AEP , ERCOT, CNP, Oncor, Aurora Energy Research

Savings for residential ratepayers could become meaningful if a large portion of planned high voltage projects were to be competitively procured

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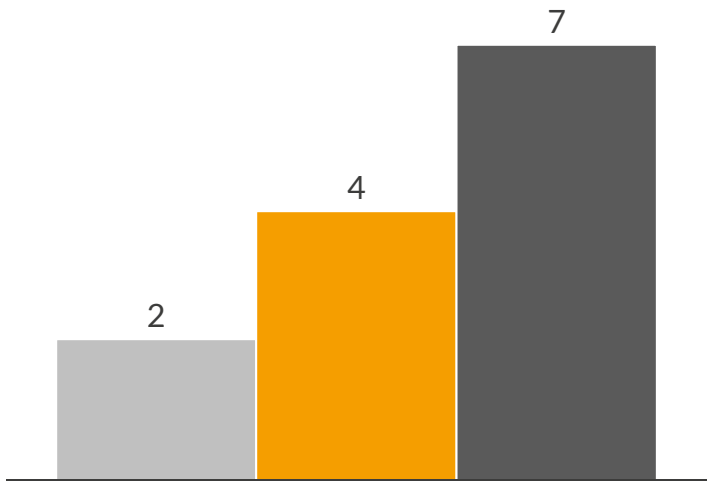
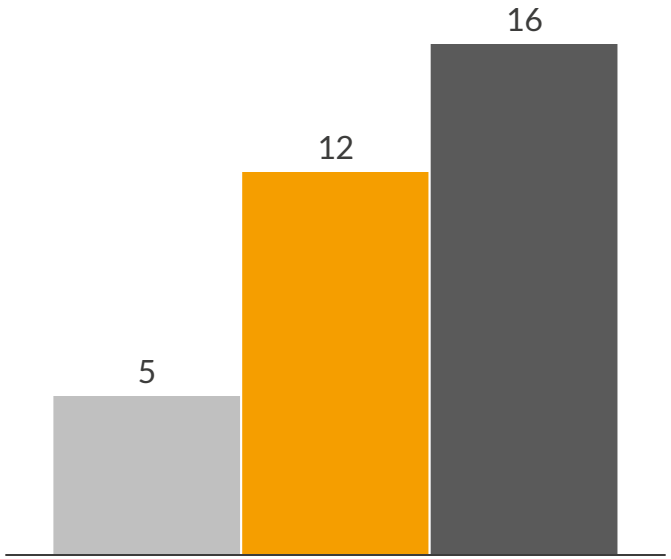
Upfront CAPEX Savings

$bn (real 2025)



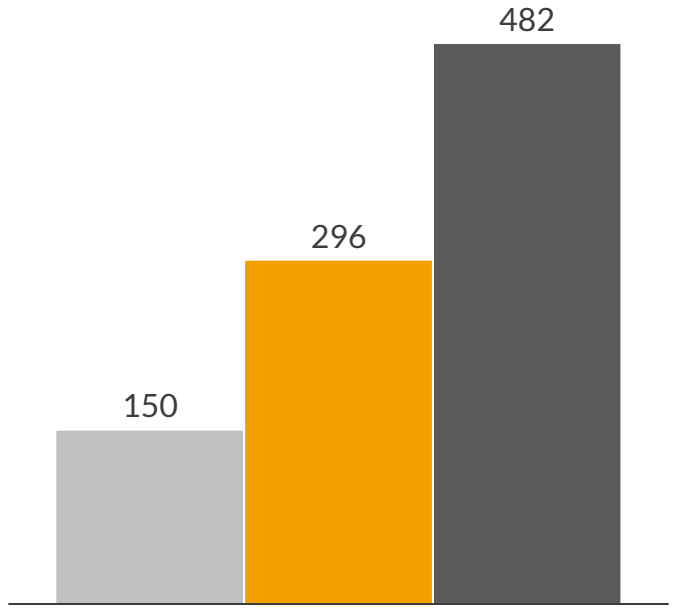
Total Lifetime Ratepayer Savings

$bn (real 2025)



Total Lifetime Savings per Household

$/residential account (real 2025)



765kV only, Permian excluded | 765kV and all 345kV upgrades, Permian excluded | Complete STEP Allocation

- The 2024 and 2025 ERCOT RTP's outlined $36 billion in allocated costs for the entire STEP Program. Excluding the Permian import path projects leaves $13.8 billion and further excluding all lower-voltage lines and upgrades leaves ~$9.1 billion. Reconsideration of Permian 765kVs for competitive allocation has the potential to contribute nearly $3 billion to upfront CAPEX savings.
- Consideration of all unallocated lines alone (765kV only, Permian excluded) provides a potential opportunity to achieve ~$5 billion in lifetime ratepayer TCRF[1] savings.

1) Transmission Cost Recovery Factory (TCRF).

Sources: PUCT, AEP , ERCOT, CNP, Oncor, Aurora Energy Research

Competition on future high voltage lines could significantly reduce CAPEX and help offset rising transmission charges for ERCOT residential ratepayers

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~19%
Capex savings assumption
Successful competitive projects average

~$7 billion
Potential STEP CAPEX reduction
~$36.4bn to ~$29.6bn

~$16 billion
Lifetime total ratepayer savings
If eligible STEP programs are built collectively

~$482
Lifetime savings per household
Service-area-wide estimate

1 Procurement design determines who bears risk

- Non-competitive projects are assigned to incumbents
- Cost overruns can flow through regulated rates
- Competitive bids add price discovery, caps and disclosure

2 Transmission charges already matter on bills

- TCRF contributes 5-15% of a typical bill
- Representative TCRF is ~2.19¢/kWh
- TCRF increased ~34% over two years

3 These lines are a natural target for savings

- Competitive path implies ~$36.4bn vs ~$29.6bn baseline
- Rate model indicates up to -0.21¢/kWh residential impact in a single year[1]
- Maximum 5-year residential savings of ~$116 per customer[2, 3]

Introducing competition for eligible STEP projects can transfer performance risk to developers, create cost discipline, and convert CAPEX savings into direct TCRF relief for customers[1].

1) 2033. 2) All figures indicative and based on current benchmark assumptions, filed ROEs, Aurora rate model inputs and preliminary STEP cost estimates. 3) 5-year period is 2032-2036.

Sources: PUCT, AEP , ERCOT, CNP, Oncor, Aurora Energy Research

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Cross-project comparability between projects, cost-cap design in various markets, and limited data transparency are key caveats of the analysis

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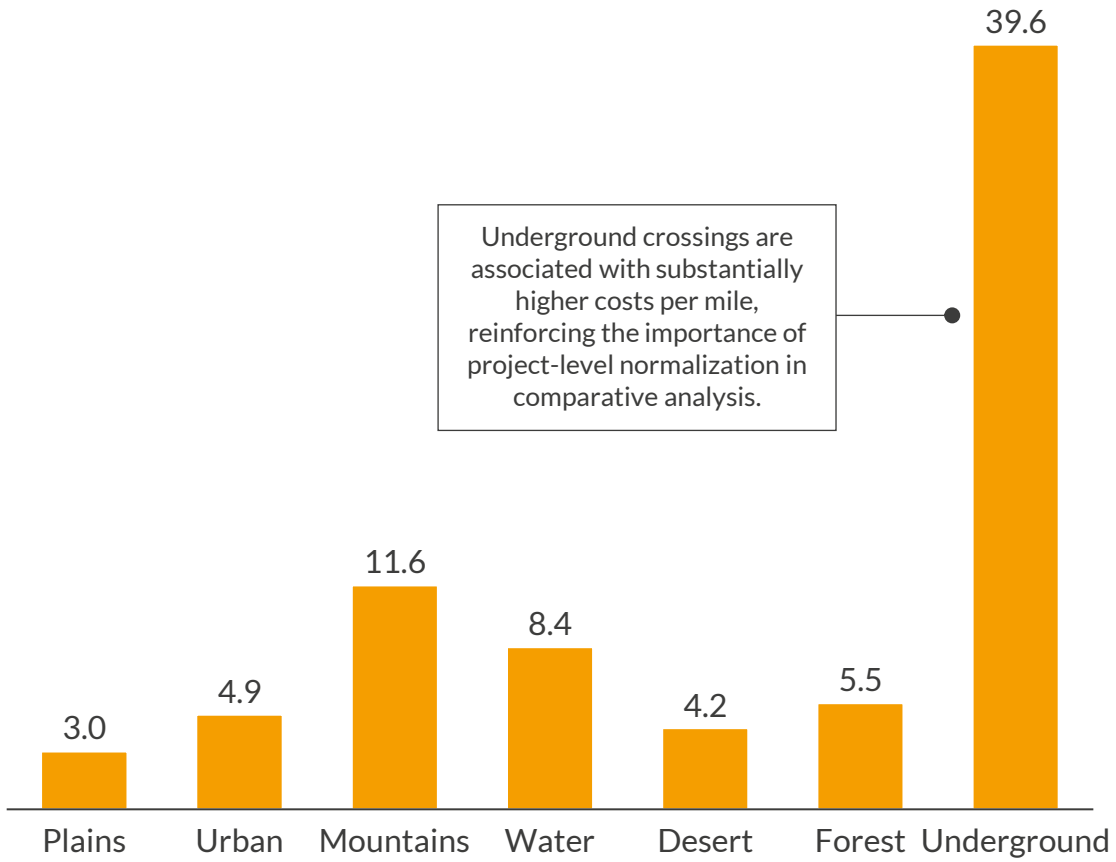
Main Caveats — **Project scope, data limitations, unforeseen costs**

Project scope	▪ Cross-market level comparisons are influenced by terrain, scope size, and broader economic conditions ▪ Cost, date baselines differ by procurement model: SPP, MISO, CAISO use project model; PJM, NYISO use a sponsorship model ▪ Per-mile metrics are a rough proxy which ignore crew count, terrain, double-circuit scope, outages
Data limitations	▪ Small data samples limit strength of conclusions drawn and observable trends, since very few competitively-selected projects have been completed since FERC Order 1000 ▪ Many projects – non-competitive in particular – have no online public record with essential cost and project metrics
Unforeseen costs	▪ Even projects with cost commitments see overruns, which can be exempt from project cost

Cost per mile by terrain
$ mn/mile (2025 real)



Sources: Aurora Energy Research, FERC, PUCT, SPP, MISO, CAISO, ERCOT, NYISO, PJM

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Overview of all competitive and non-competitive projects studied

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Market	# Competitive	Competitive Developers	Competitive Projects	# Non-Competitive	Non-Competitive Developers	Non-Competitive Projects
ERCOT	7	Lone Star; Cross Texas; Wind Energy Transmission Texas	Central A to Central C to Sam Switch to Navarro; Scurry County South to Long Draw to Grelton to Odessa; Long Draw to Sand Bluff to Divide to Bearkat; Cottonwood to Dermott; Gray to White Deer; Gray to Tesla; Silverton to Tesla	11	STEC; Garland; Oncor; CNP; AEP; ETT; LCRA	McCamey C to McCamey A to Odessa; West B to Moss; Willow Creek to Hicks; West Krum to Anna; Oklaunion to West Krum; Central B to Willow Creek (Oncor Portion); Bailey to Jones Creek; Bakersfield to Solstice; Angstrom to Grissom; Lobo to North Edinburg
MISO	1	Republic Transmission	Duff–Coleman	5	ITC Midwest; Otter Tail; MDU; Xcel; Great River Energy; Dairyland; SMMPA; RPU; WPPI	Cardinal to Hickory Creek; Big Stone South to Brookings; Brooks County to Hampton; Fargo to Monticello to St. Cloud; Hampton to Rochester to La Crosse
PJM	2	Transource; Silver Run Electric; PSE&G; Delmarva Power	Thorofare Creek-Goff Run-Powell Mountain; Artificial Island	3	FirstEnergy/ATSI; PPL Electric/PSE&G	Bruce Mansfield to Glenwillow; Susquehanna to Roseland; Trans-Allegheny Interstate Line
NYISO	3	National Grid; NY Transco; NextEra	Empire State Line; AC Transmission Segment A; AC Transmission Segment B	2	NYSEG/NY Transco; NYPA/National Grid	Fraser-Coopers Corners; Smart Path South
SPP	4	NextEra; Transource	Crossroads-Hobbs Roadrunner; Minco-Pleasant Valley-Draper; Wolf Creek-Blackberry; Sooner-Wekiwa	4	Southwestern Power Service (Xcel); Oklahoma Gas & Electric	Hitchland-Woodward; Muskogee-Seminole; Tuco-Woodward; Sunnyside-Hugo
CAISO	3	Desert Link; Abengoa & Starwood; NextEra	Harry Allen to Eldorado; Ten West Link; Suncrest SVC	2	SDG&E; Citizens Sunrise; Southern California Edison	Sunrise Powerlink; Tehachapi Renewable Transmission Project Segments 4-11

Sources: Aurora Energy Research, ERCOT, MISO, PJM, NYISO, SPP, CAISO

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Aurora Energy Research is the leading global provider of bankable power market analytics. Founded by college professors, we've grown into a team of over 1,000 professionals worldwide, helping major energy market participants navigate their most complex, long-term decisions.

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  - Ontario
- Mexico
- United States
  - CAISO
  - ERCOT
  - ISO-NE
  - MISO
  - NYISO
  - PJM
  - SERC
  - SPP
  - WECC

SOUTH AMERICA

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- Chile
- Colombia
- Peru

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- Czechia
- Denmark
- Estonia
- Finland
- France
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- Greece
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- Ireland I-SEM
- Italy
- Kosovo
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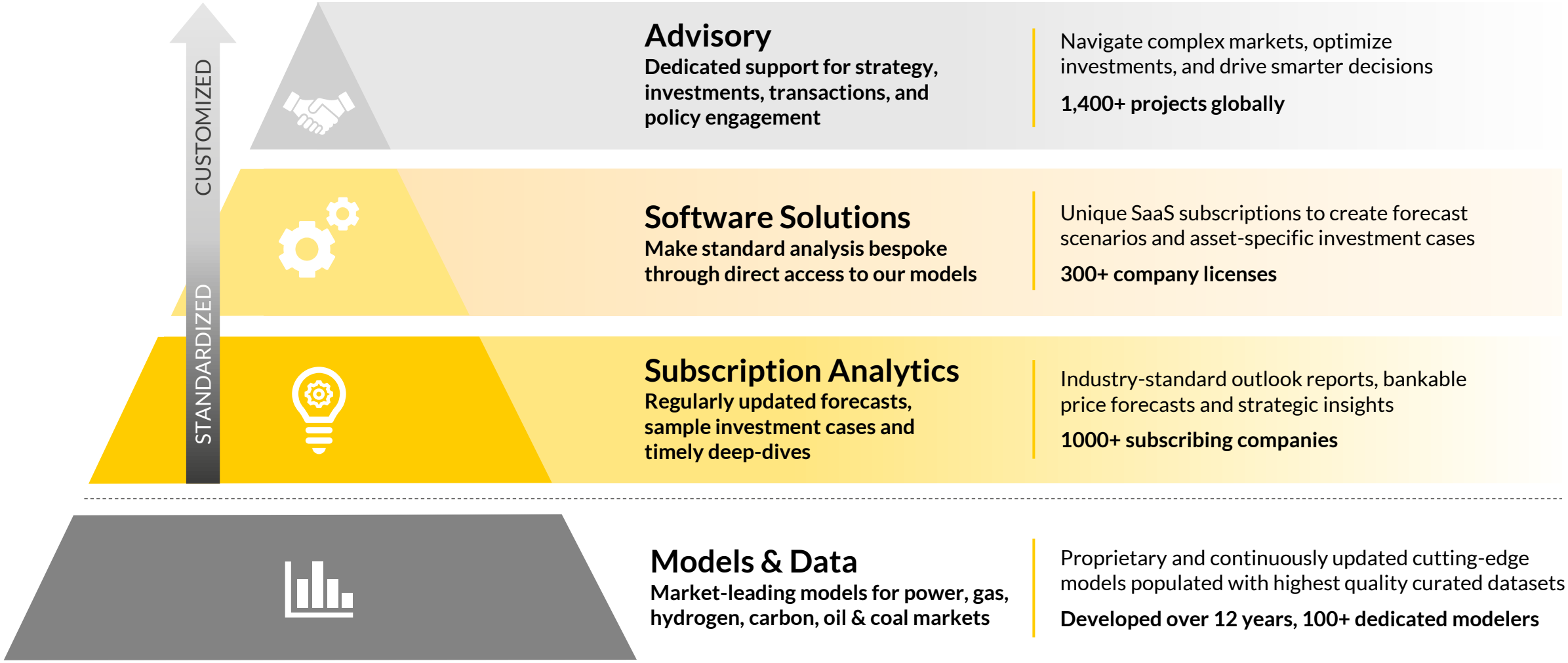

Source: Aurora Energy Research

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5 Integrated Models

Global Commodities (AER-GLO) ↔ Hydrogen (AER-HY)

Gas (AER-GAS) ↔ Power markets (AER-ES) → Nodal/network model (AER-EN)

INPUTS

- Technology
- Policy
- Demand
- Commodity prices[1]
- Weather patterns

Dispatch model

- ½ hourly or hourly
- Iterative modeling
- Dynamic dispatch of plant
- Endogenous interconnector flows

Continuous iteration until an equilibrium is reached

Investment decisions module

- Capacity market modeling
- Capacity build / exit / mothballing
- IRR / NPV driven
- Detailed technology assessments

OUTPUTS

- Capacity mix
- Generation mix
- Wholesale & imbalance prices
- Capacity market prices
- Profit / Loss and NPV
- Electric vehicle charging

ADDITIONAL INPUTS

- Network snapshot - existing & future
- Nodal load map
- Nodal generation map

OUTPUTS

- Power flows & losses
- Nodal prices / loss factors

Up to 70 specifications modeled for each plant

c. 85k investment hours on modeling capabilities

~15k model runs per week

50+ strength of modeling team globally

Quarterly updates through subscription research

1) Gas, coal, oil and carbon prices fundamentally modeled in-house with fully integrated commodities and gas market model.

Sources: Aurora Energy Research

Details and disclaimer

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