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ELECTRIC POWER

Evaluating the Cost of ERCOT's Permian Basin Reliability and Strategic Transmission Expansion Plans

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Introduction

In May 2023, the Texas House Bill 5066, authored by Representative Charlie Geren, mandated that the Public Utility Commission of Texas (PUCT) direct the Electric Reliability Council of Texas (ERCOT) to create a plan to address electricity demand growth in West Texas over the next decade. The anticipated load growth is driven by the electrification of oil and gas operations, the construction of large load data center facilities, and other industrial expansions. In December 2023, the PUCT formally issued the Permian Order to ERCOT. In July 2024, ERCOT presented a final report on the Permian Basin Reliability Plan (PBRP) to the PUCT. In September 2024, the PUCT approved ERCOT's PBRP.

As it stands at the preparation of this report, the PBRP was adopted as part of ERCOT's strategic transmission expansion plan (STEP). The PBRP includes several local transmission upgrades, the construction of three 765-kV transmission lines in ERCOT, and a cost estimate of ~$14 billion.[1] In addition, the STEP includes two 765-kV transmission lines between the North and South zones of ERCOT. However, if demand growth does not materialize or is significantly lower than the current projected level, the 765-kV lines investment would result in billions of dollars in stranded assets.

The high price tag of the PBRP and STEP, as well as the lack of publicly available analysis of alternative plans, has prompted stakeholders to conduct their own independent analyses. In collaboration with the Texas Public Policy Foundation (TPPF), Energy Ventures Analysis (EVA) has evaluated alternatives to the PBRP and STEP. These alternatives evaluated the build-out of generation additions to meet growing demand as an alternative to the proposed 765-kV lines. The results show that future demand could be met without the 765-kV lines at a similar cost, and this will be explored in further detail throughout this report.

Methodology

EVA's energy forecasts are formulated using a bottom-up approach combining detailed market data and analysis with rigorous engineering principles. For example, EVA's power team inputs its latest market research and analysis into the model. These inputs include electricity demand, capital costs for new market entrants by technology (e.g., combined cycle gas turbines (CCGT), simple cycle gas turbines (SCGT), wind, solar, storage, nuclear, coal with carbon capture and storage (CCS)), recently announced retirements and new builds, and future operation and maintenance (O&M) cost changes due to environmental retrofits, among others.

Model

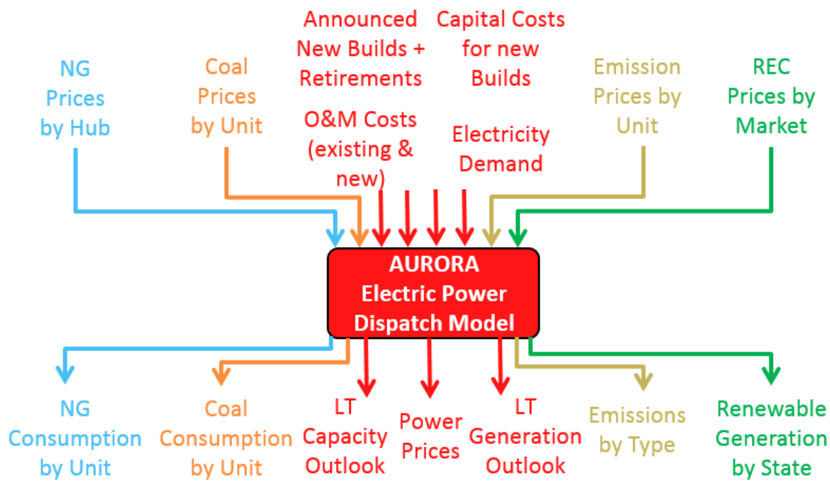
EVA licenses the Aurora dispatch model from Energy Exemplar and has undergone an extensive customization process to repopulate the defaults with data from EVA's own market research and insights. Some of the customizations include:

- Complete overhaul of grid-connected generating capacity based on the most recent Energy Information Administration (EIA) data and EVA's proprietary Power Plant Tracking System
- Unit-specific scheduled and unscheduled maintenance outage rates based on historical performance
- Unit-specific heat rates based on historical performance and engineering principles
- Unit-specific emission rates based on historical performance and future emission control technologies
- Hourly utilization rates for solar and wind resources based on location and technology
- Unit-specific minimum up/downtime, ramp rates, and minimum load requirements based on historical performance and engineering principles
- Planning reserve margin requirements based on published Regional Transmission Organizations (RTO) and North American Electric Reliability Corporation (NERC) targets
- Capital cost, operational characteristics, and online dates for new entrants reflective of real-world data

[1] https://www.rtoinsider.com/wp-content/uploads/2025/01/ERCOT-PB-Plan-Jul-24.pdf

EXHIBIT 1 shows key inputs and outputs of the Aurora electric dispatch model, the cornerstone of EVA's integrated forecasts.

EXHIBIT 1: INPUTS AND OUTPUTS OF EVA'S AURORA ELECTRIC POWER DISPATCH MODEL



Other Inputs

Natural Gas Price Outlook

Henry Hub prices have been volatile, with the 2025-2026 winter season bringing sharp swings driven by weather events and record liquefied natural gas (LNG) feed gas demand. Near-term, prices are expected to remain in the mid-$3/MMBTU range through the injection season as storage inventories normalize from winter draws. Looking further out, EVA's base case projects a materially higher price environment over the long term, with Henry Hub rising from the mid-$3s to levels above $8/MMBTU in real terms by 2050. This upward trajectory reflects a tightening market driven by accelerating electricity demand from data center growth and electrification, combined with sustained LNG export expansion pulling on domestic supply. Production responds but increasingly requires development in higher-cost pure-play gas basins, such as the Permian, drilled but uncompleted (DUC) backlog thins, and productivity gains plateau, lifting the marginal cost of supply over time.

Powder River Basin (PRB) Coal Price Outlook

PRB coal prices have been very stable since 2013, with the prompt-year forward market price (most PRB coal is purchased under annual contracts) for 8,800 Btu coal ranging from $11.00 to $15.00 per ton, over 80% of the time. Except for a 5-month period from September 2021 to January 2022, the forward price has never been above $17.10 per ton. The price spike in late 2021 was driven by a sharp increase in demand for PRB coal amid a jump in natural gas prices during the recovery from the COVID recession.

EVA projects PRB coal prices to remain stable, growing very slowly in constant 2025 dollars, and growing with inflation in nominal dollars. Except for short periods of imbalance between supply and demand, we project market prices for 8,800 Btu coal to be in the range of $15.00 - $17.00 per ton in constant 2025 dollars. Prices can drop below production costs for short periods when demand falls, forcing mines to reduce production, and can rise well above production costs during periods of a surge in demand. The primary driver of short-term swings in demand will be changes in winter weather, which affect the demand and price of natural gas, causing the economic dispatch of PRB power plants to vary coal burn in response.

Capital Costs for New Generating Units

EVA forecasts technology-specific capital costs for new builds by tracking current project costs, future changes in labor and materials costs, and relevant subsidies. For example, the federal tax credits for solar and wind resources have been updated to have an early expiration date under the One Big Beautiful Bill Act (OBBBA). The cost of required environmental upgrades is also included based on publicly available data and EVA estimates. **EXHIBIT 2** provides the capital cost estimates incorporated into EVA's analysis.

EXHIBIT 2: OVERNIGHT CAPITAL COSTS FOR DIFFERENT GENERATION TECHNOLOGIES THROUGH 2050

	Capital cost ($2025/kW)	2025	2026	2030	2035	2040	2045	2050
Thermal	**Gas CC**	$2,290	$2,320	$1,970	$1,770	$1,570	$1,460	$1,360
	Gas CT	$1,830	$1,860	$1,580	$1,180	$980	$880	$780
	Gas CC w/ CCS			$3,230	$2,760	$2,420	$2,170	$1,920
	Coal w/ CCS			$6,400	$6,030	$5,710	$5,360	$5,050
	Nuclear - SMR			$10,340	$9,360	$8,470	$7,970	$7,850
Non-thermal	**Solar PV**	$1,580	$1,560	$1,500	$1,410	$1,420	$1,430	$1,440
	Onshore Wind	$1,930	$1,920	$1,840	$1,790	$1,760	$1,730	$1,700
	Offshore Wind		$6,080	$5,740	$5,320	$4,930	$4,790	$4,670
	Battery Storage - 4-hr	$1,710	$1,690	$1,610	$1,600	$1,610	$1,630	$1,660
	Solar + Storage	$2,480	$2,480	$2,480	$2,510	$2,560	$2,630	$2,740

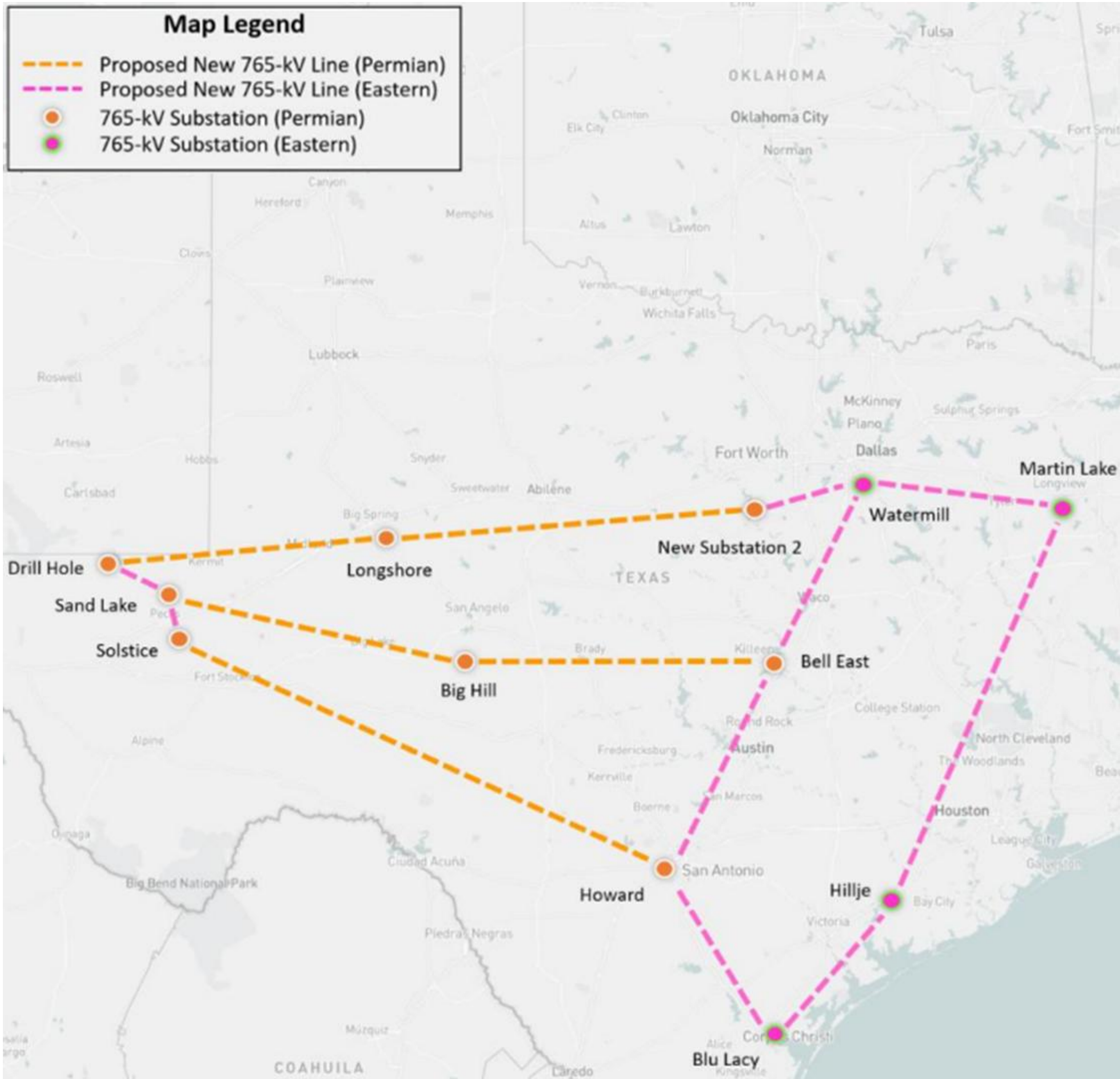
Representing the PBRP and the STEP

EVA's license of the Aurora power dispatch model from Energy Exemplar also includes a long-term capacity expansion (LTCE) feature that enables the model to build new generation to meet future demand at the lowest system cost. This is an important difference between our analysis and ERCOT's analysis. ERCOT's PBRP report refers to the Generator Interconnection Status (GIS) report as the basis for generator additions. However, these additions were limited to commercial operation dates before 2030, despite the analysis period extending to 2038. In EVA's analysis, the LTCE study period was 25 years (2026-2050). The EVA LTCE methodology provides a detailed understanding of the build-out of generation additions and the associated costs, with and without the 765-kV lines.

EVA ran an LTCE without any 765-kV transmission lines, a second LTCE with the planned 765-kV transmission lines for the PBRP, and a third LTCE with the planned 765-kV transmission lines for the STEP, comparing generation needs in each zone and the resulting cost impact. EVA performed this comparison for three different demand scenarios. This approach isolated the impact of the planned 765-kV transmission lines by keeping everything else constant and adding or removing only the 765-kV transmission lines. EVA modeled the PBRP 765-kV transmission lines as two 2,100 MW lines from North to West and one 2,100 MW line from South to West, coming online in 2031.[2] EVA modeled the STEP 765-kV transmission lines as the three PBRP lines plus two 2,100 MW lines from North to South, coming online in 2031. The 765-kV transmission lines are configured to be bidirectional. An overview of the approved plan as proposed in the 2024 regional transmission plan is provided in **EXHIBIT 3** below.[3]

[2] https://www.rtoinsider.com/wp-content/uploads/2025/01/ERCOT-PB-Plan-Jul-24.pdf
[3] https://www.ercot.com/mp/data-products/data-product-details?id=pg7-048-m

EXHIBIT 3: MAP OF THE 765-KV STRATEGIC TRANSMISSION EXPANSION PLAN (STEP)



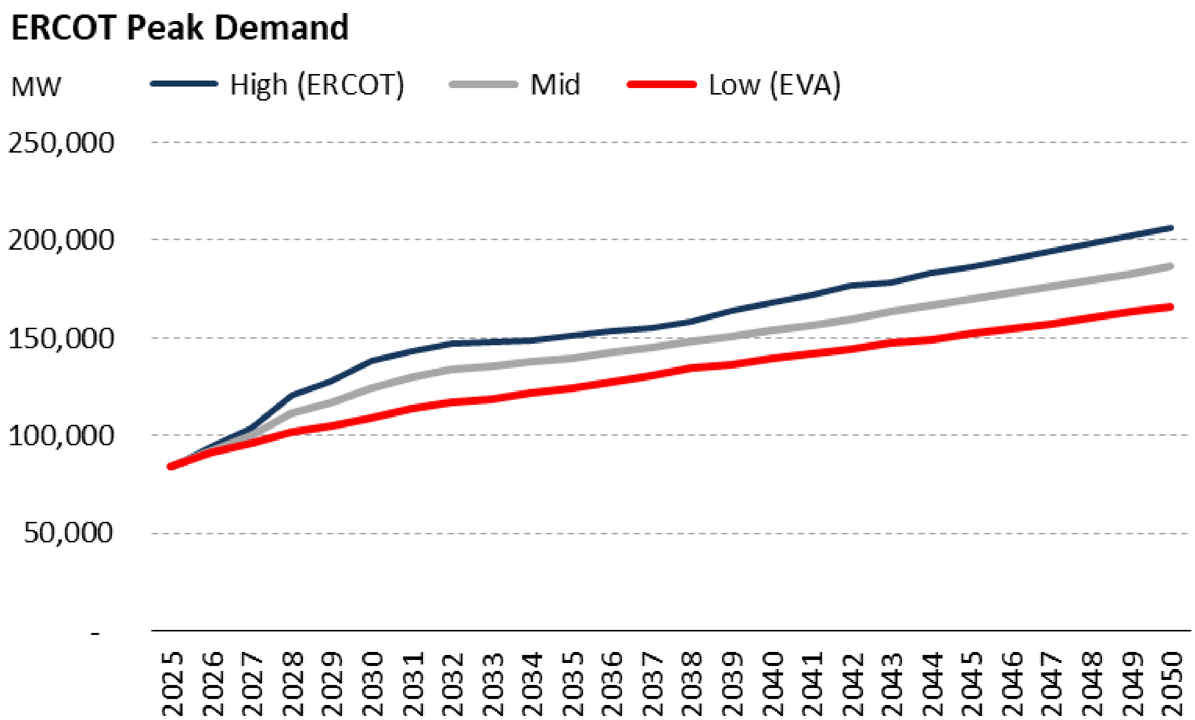
Scenarios

EVA compared three different demand scenarios for ERCOT, as shown in **EXHIBIT 4**, to analyze the impact of demand growth on the need for new generation, its cost implications, and to accurately quantify the risks. The first, referred to as the high case, utilized ERCOT's 2025 hourly long-term energy forecast, which was directly input into the model.[4] The second, referred to as the low case, uses EVA's forecast, which is based on socioeconomics and a combination of other factors, including large loads, electrification, efficiency, and distributed generation. Finally, the third demand scenario, referred to as the mid case, represents the potential between the high and low cases. Much of the growth is expected to occur before the 765-kV lines come online in 2031. The only way to meet that demand would be with new capacity, unless

[4] https://www.ercot.com/files/docs/2025/04/08/2025-ERCOT-Monthly-Peak-Demand-and-Energy-Forecast.xlsx

the demand growth is delayed. **EXHIBIT 5** shows that West demand remains a smaller share of total ERCOT demand than the North and South throughout the study period, even though, in the short term, West demand is growing faster.

EXHIBIT 4: ERCOT PEAK DEMAND THROUGH 2050



Source: ERCOT and EVA

EVA uses a combination of state-level socio-economic factors, such as GDP, industrial production, employment, and disposable income, as inputs to advanced regression models to forecast electric demand by ISO zone, NERC sub-region, and major utility. In addition, EVA adds a layer of forecasts for distributed generation, energy efficiency, electrification of buildings and transportation, and data centers. Demand is further adjusted for normalized weather. Hourly demand shapes are also normalized from the last three to five years.

EXHIBIT 5: ERCOT TOTAL DEMAND BY WEATHER ZONE [5]

TWh	2025	2030			2038			2050		
ERCOT Weather Zone	Actual	High	Mid	Low	High	Mid	Low	High	Mid	Low
Coast	123	187	165	144	206	181	156	250	220	180
East	17	21	19	17	24	21	19	31	27	22
Far West	65	146	117	89	186	154	122	236	200	162
North	15	66	46	26	81	63	45	95	82	66
North Central	134	221	193	167	268	233	197	331	288	235
South	36	93	75	57	106	88	70	115	99	81
South Central	84	194	146	97	253	197	140	311	262	211
West	12	56	39	21	59	45	32	67	57	46
ERCOT	**486**	**984**	**798**	**618**	**1,184**	**983**	**781**	**1,437**	**1,236**	**1,004**

[5] The appendix includes a table with CAGRs for the three demand cases.

EXHIBIT 6: ERCOT PEAK DEMAND BY WEATHER ZONE [6]

MW	2025	2030			2038			2050		
ERCOT Weather Zone	Actual	High	Mid	Low	High	Mid	Low	High	Mid	Low
Coast	22,083	29,115	27,996	27,017	30,694	29,478	28,448	39,404	35,066	30,561
East	3,040	3,435	3,361	3,324	3,793	3,621	3,446	4,806	4,197	3,616
Far West	10,830	18,225	15,295	12,530	22,438	19,877	17,306	28,724	25,105	21,406
North	2,593	8,354	6,294	4,460	10,014	8,782	7,571	12,104	11,282	10,511
North Central	27,582	35,940	34,660	33,764	41,713	39,374	38,020	56,022	50,353	45,004
South	6,432	12,954	11,108	9,597	15,031	13,594	12,344	17,595	15,739	14,151
South Central	15,323	27,087	22,408	17,732	34,724	28,686	24,287	43,832	39,258	35,620
West	2,083	7,116	5,257	3,463	7,477	6,280	5,227	8,715	7,644	6,793
ERCOT	**83,878**	**137,995**	**124,251**	**109,302**	**158,008**	**148,112**	**134,659**	**206,098**	**186,369**	**165,923**

Results

EVA compared the generation additions to meet demand without the 765-kV transmission lines, with the PBRP, and with the STEP before and after construction, keeping everything else constant. EVA then calculated the capital costs associated with the different generation additions. Finally, EVA also evaluated the impact on power prices and the potential benefits and savings available with alternative approaches to the 765-kV lines to meet demand.

Generation Additions

Existing generating capacity is generally distributed with renewable generation in West Texas and conventional generation near load centers in the North, South, and Houston. Traditionally, gas generation has not been built in the West because of fuel supply risk, a lack of load demand, low revenue because of no capacity payments and suppressed power prices with infrequent spikes from high renewable penetration that is consistently trapped locally because of congestion, and reliance on imported thermal generation from the North and South zones. However, the current demand outlook could significantly shift these dynamics. Gas generation additions could become favorable if around-the-clock demand materializes in the Permian Basin. In fact, extended interconnection timelines are prompting developers to pursue behind-the-meter generation across the country, especially in Texas, which could lead to demand growth overestimation and put the PBRP 765-kV lines at risk of becoming stranded assets.[7]

The 765-kV transmission lines do not reduce the need for generation by much for every demand case, as shown in **EXHIBIT 7**. On average, cases without the 765-kV transmission lines add ~5% more generation than cases with the PBRP and ~7% more generation than cases with the STEP by 2038. The more significant difference lies in where the generation is built, rather than how much is built. For example, in the high-demand case without the 765-kV transmission lines, the West zone adds ~4 GW more gas-fired capacity to meet growing demand compared with the case with the PBRP, which relies on more imports. We also observed that there are fewer gas steam turbine retirements across ERCOT zones in the high-demand case with the PBRP, primarily in the North, because these generators remain competitive for imports into the West. In the mid-demand case with the STEP, the North zone installs less solar than in the case without the 765-kV lines and relies more on imports from the South.

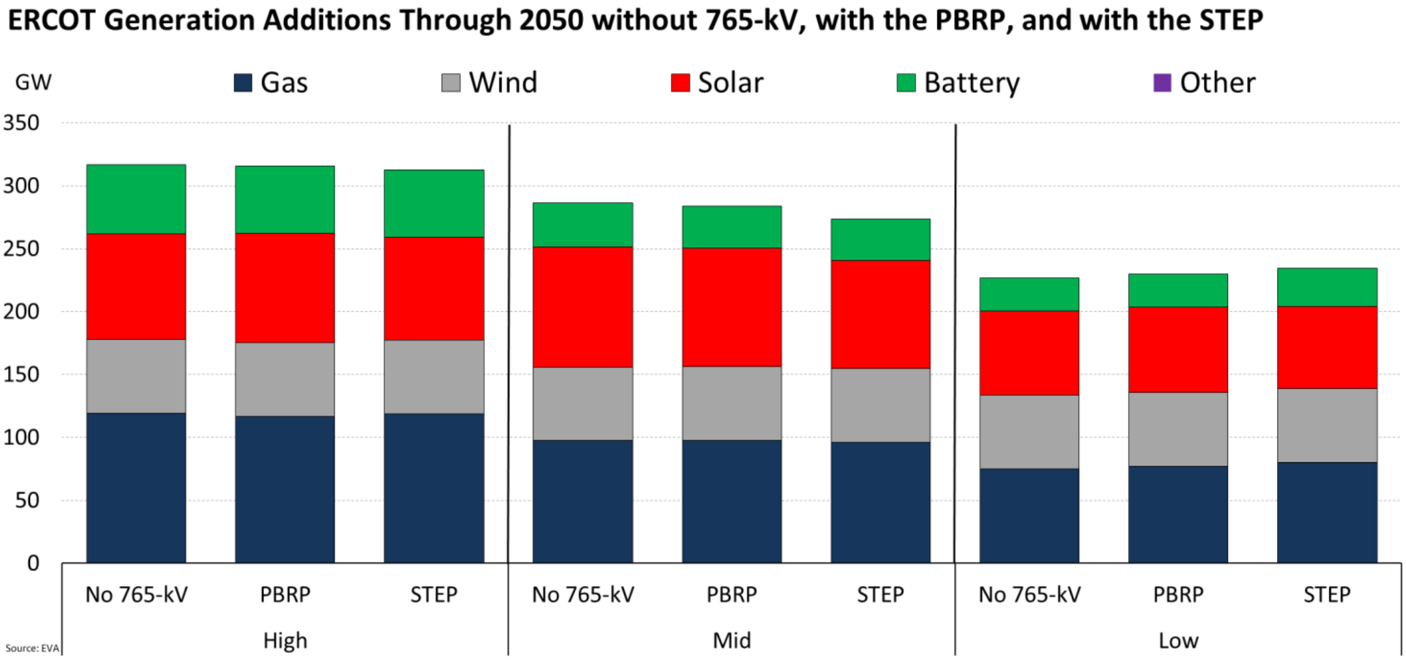
Renewable additions, especially solar, decline noticeably from 2031 to 2038 across all demand cases because they cannot meet evening demand peaks on their own. As previously mentioned, we project that federal production and investment tax credits (PTC and ITC) will expire by 2029, in line with the OBBBA, making renewables less competitive to build than gas

[6] The sum of the weather zone peaks is not equal to the total ERCOT pool peak because the weather zone peaks are not necessarily coincidental.

[7] https://cleanview.co/content/power-strategies-report

until costs begin to decline organically. Dispatchable generation required to meet evening peaks creates a barrier to additional solar generation. Gas assets are more attractive than renewables because of low gas prices in West Texas, greater dispatchability driven by demand growth, and higher effective load-carrying capability (ELCC).

EXHIBIT 7: ERCOT GENERATION ADDITIONS THROUGH 2050 WITHOUT 765-KV, WITH THE PBRP, AND WITH THE STEP [8]



Transmission Utilization

Historically, West Texas has been a net power exporter of renewable generation, constrained by transmission capability. ERCOT's long-term demand forecast suggests that the West zone interchange dynamics could be extended to include renewable exports to the Permian Basin and a greater reliance on thermal generation imports from the East during periods of low renewable generation. In the PBRP report, ERCOT noted that the 765-kV lines were designed with the Permian Basin's and the overall ERCOT system's needs in mind. ERCOT suggests that the PBRP could be used to import generation into the Permian Basin to serve forecasted load and to export renewable generation from West Texas to load centers in the East. However, demand in the West zone and ERCOT overall is expected to grow starting in 2026, while the 765-kV transmission lines are expected to come online in 2031. Since ERCOT is already constrained, the additional demand will require new generation to come online before 2030.

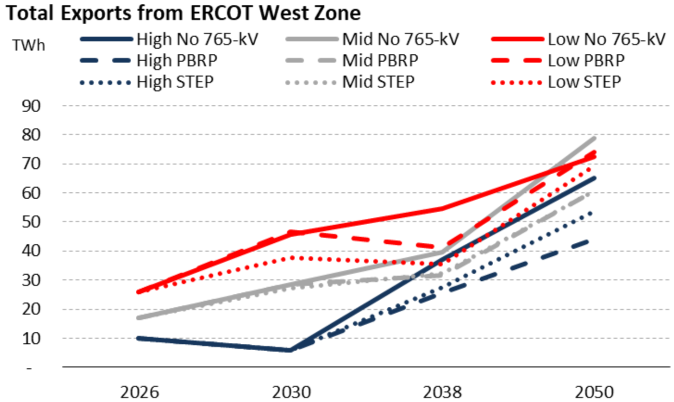
In our analysis, the 765-kV lines do not significantly change the zonal imports and exports, as shown in **EXHIBIT 8**. The West zone relies more on generation additions than on imports to meet growing demand. Not surprisingly, exports from the West zone, which is currently cited as a constraint, increase over time in all demand cases, but are lower with the 765-kV PBRP and STEP lines. Lower exports from the West zone in cases with the 765-kV transmission lines can be explained by higher generation additions and increased interchange between the North and South zones, eliminating the need for additional imports from the West. Imports into the West zone are higher when the 765-kV PBRP and STEP lines are included and change less over the study period, despite a significant near-term increase in the high-demand case. Exports from the North zone gradually increase over the study period and are generally higher with the 765-kV PBRP and STEP lines. Imports into the North zone gradually increase and are lower with the 765-kV transmission lines. In the low case, higher exports from the West zone balance higher imports into the North zone. Exports from the South zone significantly

[8] The appendix includes detailed zonal generation additions.

drop in the high case to accommodate local load growth, but remain stable in the other cases. Exports from the South zone are lower with the 765-kV PBRP and STEP lines. Imports into the South zone gradually increase with minimal difference when the 765-kV lines are included. In general, the differences in zonal exports and imports with and without the 765-kV transmission lines are minimal. This suggests that utilization rates decline in cases with the 765-kV transmission lines, as transmission capacity increases without a significant increase in import or export volumes.

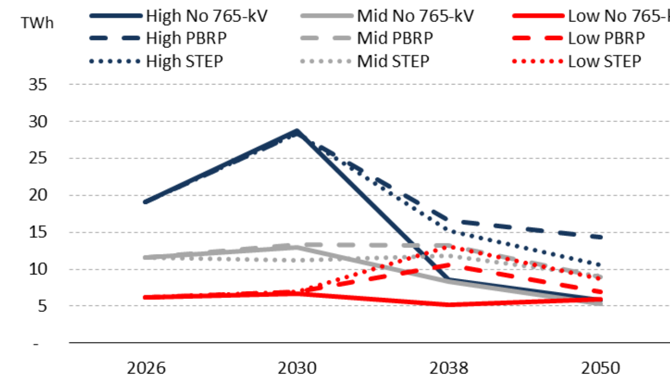
EXHIBIT 8: ZONAL IMPORTS AND EXPORTS WITHOUT 765-KV, WITH THE PBRP, AND WITH THE STEP

Total Exports from ERCOT West Zone



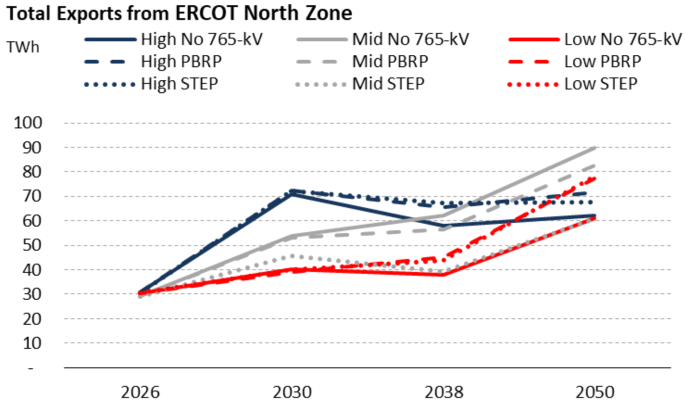
Source: EVA

Total Imports into ERCOT West Zone



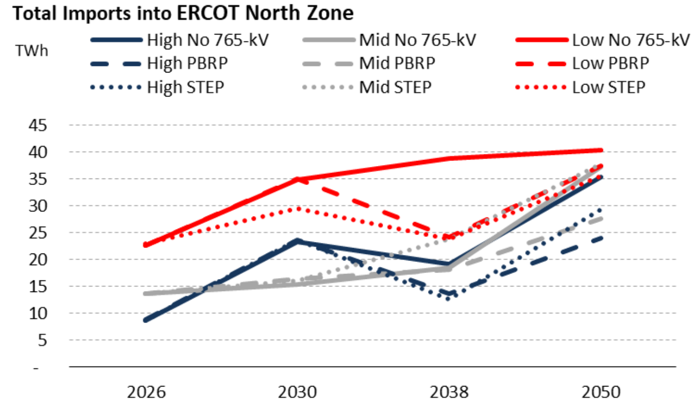
Source: EVA

Total Exports from ERCOT North Zone



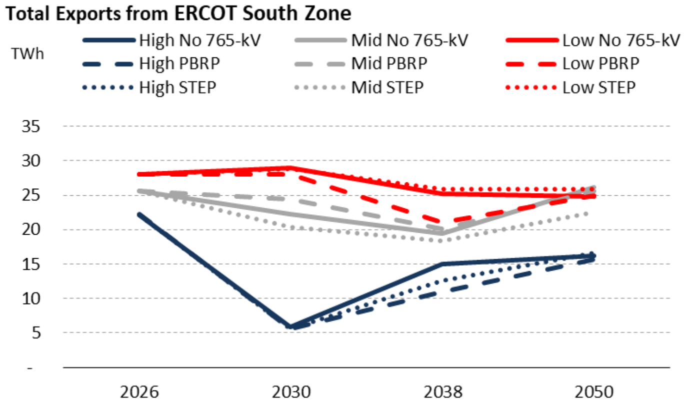
Source: EVA

Total Imports into ERCOT North Zone



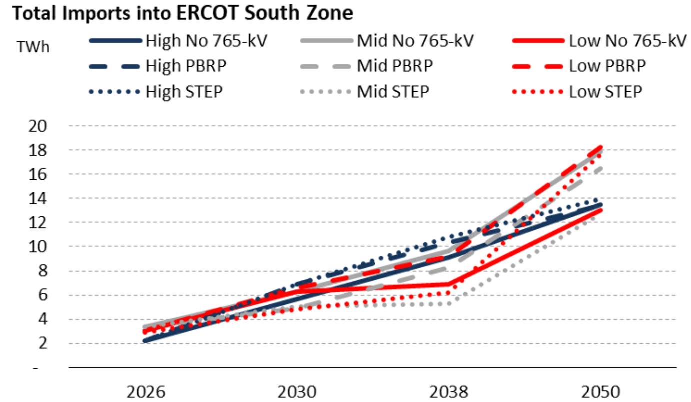
Source: EVA

Total Exports from ERCOT South Zone



Source: EVA

Total Imports into ERCOT South Zone

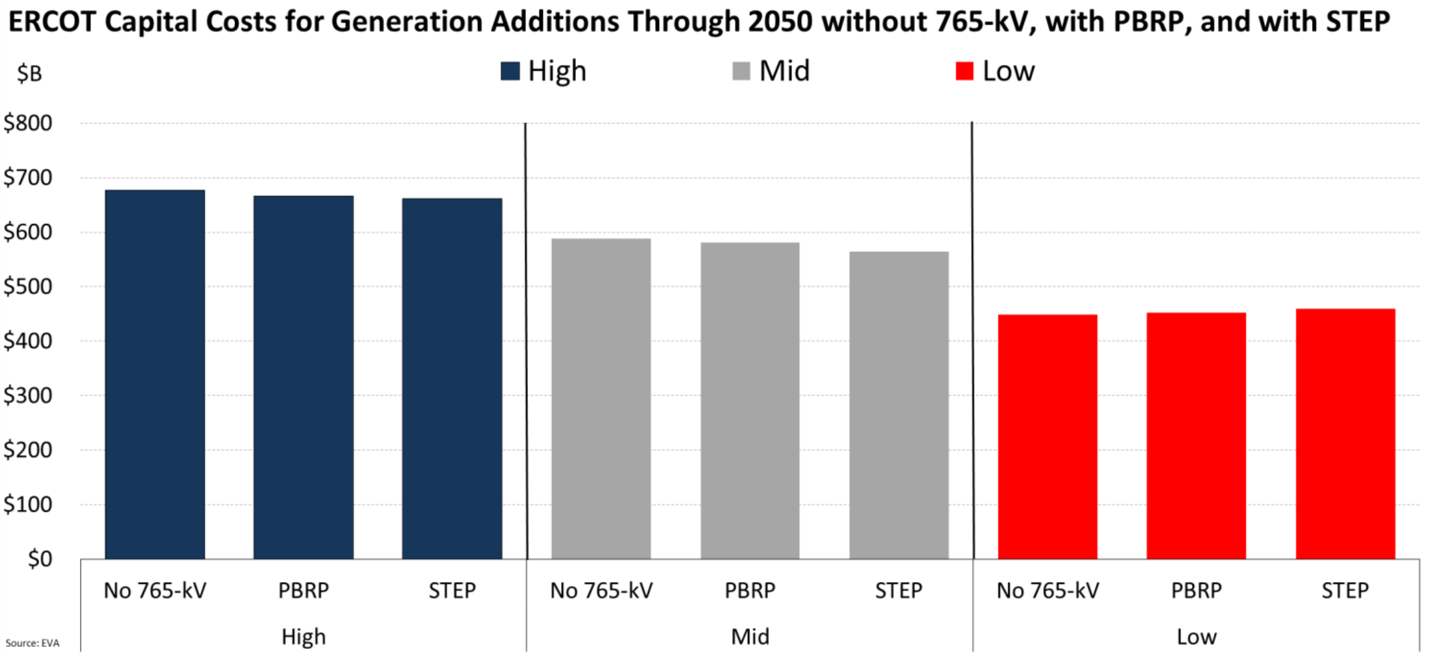


Source: EVA

Capital Costs

EVA calculated the capital costs associated with the generation additions based on the estimates provided in **EXHIBIT 2**. **EXHIBIT 9** provides a summary of the capital costs associated with generation additions across the different demand cases, without 765-kV lines, with the PBRP, and with the STEP, throughout the entire study period. The increase in generation additions across the three cases without the 765-kV lines resulted in a ~5% increase in cumulative capital costs by 2038 for both the PBRP and the STEP. If the cost estimates for the 765-kV lines are included ($9B for the PBRP and $17B for the STEP), the increase is only ~2%.

EXHIBIT 9: TOTAL ERCOT CAPITAL COSTS [9]



$B	No 765-kV			PBRP			Difference		
Time Period	High	Mid	Low	High	Mid	Low	High	Mid	Low
2026 to 2030	$296.39	$250.47	$175.66	$290.04	$244.43	$182.76	$6.34	$6.03	-$7.11
2031 to 2038	$178.63	$127.56	$109.81	$163.22	$123.39	$83.53	$15.41	$4.17	$26.28
2039 to 2050	$202.40	$210.49	$163.03	$213.32	$213.55	$185.72	-$10.92	-$3.06	-$22.69
Total	**$677.41**	**$588.52**	**$448.50**	**$666.58**	**$581.37**	**$452.02**	**$10.83**	**$7.15**	**-$3.52**

$B	No 765-kV			STEP			Difference		
Time Period	High	Mid	Low	High	Mid	Low	High	Mid	Low
2026 to 2030	$296.39	$250.47	$175.66	$290.04	$241.20	$175.01	$6.34	$9.27	$0.65
2031 to 2038	$178.63	$127.56	$109.81	$162.34	$120.82	$90.75	$16.29	$6.74	$19.07
2039 to 2050	$202.40	$210.49	$163.03	$209.56	$201.67	$194.04	-$7.16	$8.82	-$31.01
Total	**$677.41**	**$588.52**	**$448.50**	**$661.95**	**$563.69**	**$459.80**	**$15.46**	**$24.83**	**-$11.30**

System Energy Costs

EVA also calculated system energy costs based on the difference in zonal power prices between the cases without 765-kV lines, with the PBRP, and with the STEP.[10] The PBRP 765-kV lines result in slightly higher power prices in the North and

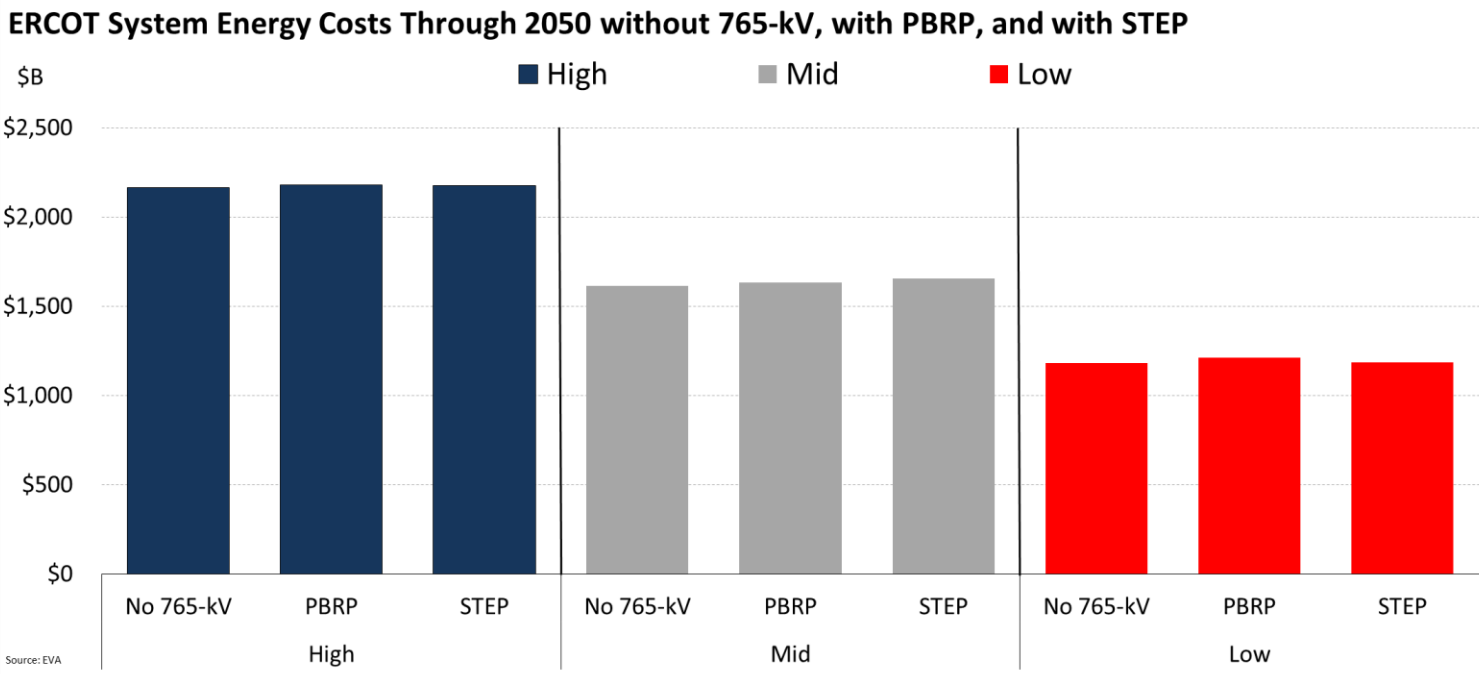
[9] The appendix includes zonal capital costs and system energy costs.

[10] The appendix includes zonal power prices for reference.

South zones because they supply power to the West zone during higher-priced hours. Prices in the West zone also decline slightly due to increased imports from the North and South zones. These changes are only a couple of dollars per MWh annually. The effects of the PBRP on power prices are dampened by the full STEP, which increases interchange between the North and South zones.

EXHIBIT 10 provides a summary of the system energy costs associated with generation across different demand cases with and without the 765-kV lines throughout the entire study period. The cases without the 765-kV lines result in ~1% decrease in system energy costs by 2038.

EXHIBIT 10: DIFFERENCE IN SYSTEM ENERGY COSTS WITHOUT 765-KV, WITH THE PBRP, AND WITH THE STEP [8]



$B	No 765-kV			PBRP			Difference		
Time Period	**High**	**Mid**	**Low**	**High**	**Mid**	**Low**	**High**	**Mid**	**Low**
2026 to 2030	$413.26	$262.04	$163.36	$413.85	$263.26	$162.14	-$0.59	-$1.23	$1.22
2031 to 2038	$605.60	$470.99	$337.73	$611.74	$474.93	$346.05	-$6.13	-$3.94	-$8.32
2039 to 2050	$1,145.35	$879.33	$680.46	$1,155.45	$894.77	$701.85	-$10.11	-$15.44	-$21.39
Total	**$2,164.21**	**$1,612.36**	**$1,181.55**	**$2,181.04**	**$1,632.97**	**$1,210.04**	**-$16.83**	**-$20.61**	**-$28.49**

$B	No 765-kV			STEP			Difference		
Time Period	**High**	**Mid**	**Low**	**High**	**Mid**	**Low**	**High**	**Mid**	**Low**
2026 to 2030	$413.26	$262.04	$163.36	$413.40	$260.91	$162.75	-$0.14	$1.13	$0.61
2031 to 2038	$605.60	$470.99	$337.73	$620.10	$484.84	$350.99	-$14.50	-$13.85	-$13.26
2039 to 2050	$1,145.35	$879.33	$680.46	$1,142.79	$909.45	$672.90	$2.56	-$30.12	$7.56
Total	**$2,164.21**	**$1,612.36**	**$1,181.55**	**$2,176.29**	**$1,655.20**	**$1,186.64**	**-$12.08**	**-$42.84**	**-$5.09**

Conclusions

In addition to local transmission upgrades and 765-kV transmission lines between the North and South zones, ERCOT's STEP adopted the PBRP, a plan to ensure the Permian Basin has access to power to support growing demand by constructing three 765-kV transmission lines to increase renewable power interchange from West to East, a widely recognized existing system constraint. However, the potential benefit of these 765-kV lines is uncertain given the range of future outcomes. For example, much of the demand growth is projected to occur before the 765-kV lines are expected to come online in 2031. The only way to meet that demand would be to add new capacity, unless demand growth is delayed. Additionally, the growing demand in the Permian Basin will provide additional load to be served by excess renewable power, reducing the need for additional transmission from West to East. In contrast, a rising interest in behind-the-meter generation, driven by long interconnection timelines, could mean demand does not materialize, eliminating the need for 765-kV transmission lines.

Our analysis evaluated changes in long-term capacity expansion without 765-kV transmission lines, with the PBRP, and with the STEP. We found that generation additions were only ~5% to 7% higher by 2038 in cases without the 765-kV transmission lines, keeping everything else constant. Furthermore, the expected demand growth is creating a case for gas in the West as dispatchability increases and tax credits for renewables expire. In cases involving the 765-kV PBRP and STEP lines, utilization rates generally decline as transmission capacity increases, without a significant increase in import or export volumes. The increase in generation additions across the cases without 765-kV transmission lines resulted in a ~2% increase in cumulative capital costs by 2038, including the respective $9B and $17B cost estimates for the PBRP and STEP 765-kV lines, respectively. Furthermore, the cases without the PBRP and STEP 765-kV lines result in a ~1% decrease in system energy costs by 2038. Once the PBRP 765-kV lines are built, power prices in the North and South zones increase because they supply power to the West zone during higher-priced hours. Prices in the West zone also slightly decline due to increased imports from the North and South zones. These changes are only a couple of dollars per MWh annually. The full STEP mitigates the impact on power prices by increasing interchange between the North and South zones. The difference in capital and system energy costs by 2038, including estimated costs for the proposed 765-kV lines, is negligible, whether or not the 765-kV lines are included, suggesting that the proposed 765-kV lines do not provide a meaningful benefit to the ERCOT system.

Appendix

Detailed Assumptions

EXHIBIT 11: HENRY HUB PRICE OUTLOOK

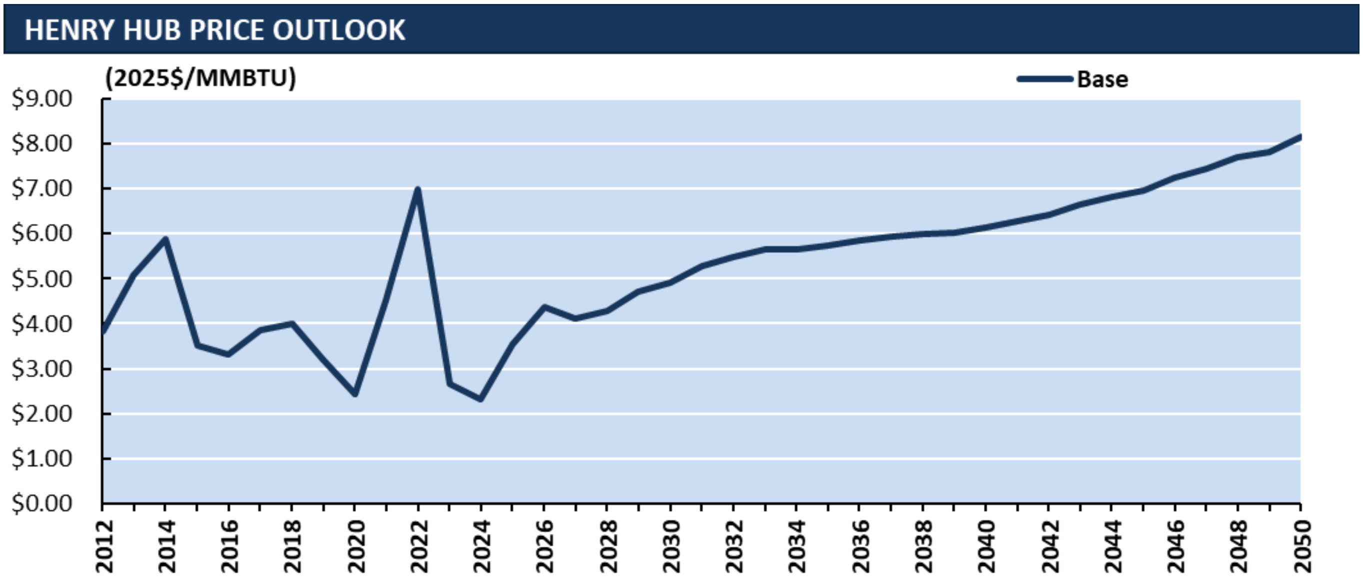
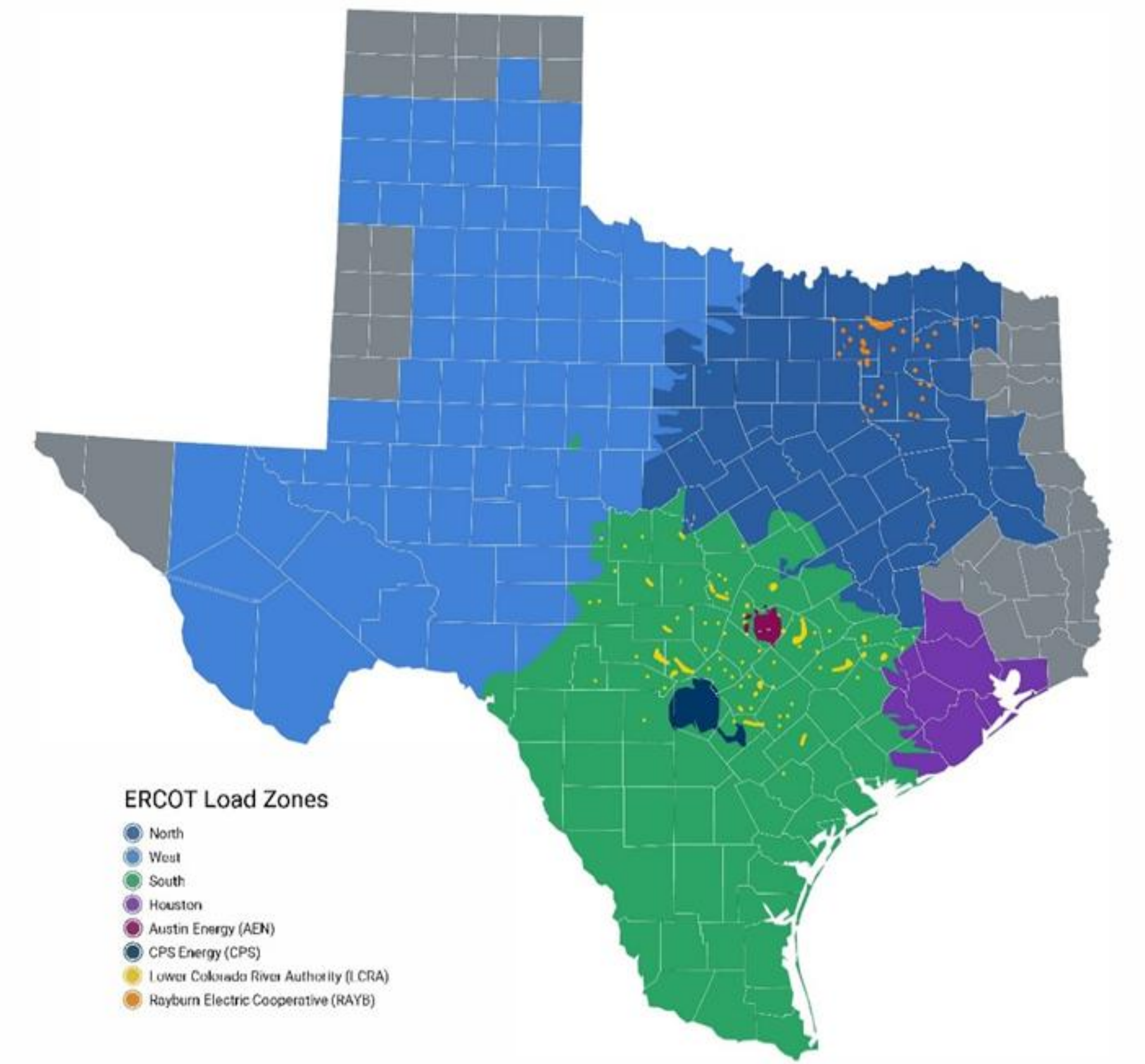


EXHIBIT 12: TOTAL DEMAND CAGR FOR ERCOT WEATHER ZONES

	2026 to 2030			2031 to 2038			2039 to 2050		
ERCOT Weather Zone	High	Mid	Low	High	Mid	Low	High	Mid	Low
Coast	10%	7%	3%	1%	1%	1%	2%	2%	1%
East	4%	3%	1%	2%	2%	1%	2%	2%	1%
Far West	10%	9%	6%	2%	3%	4%	2%	2%	2%
North	39%	29%	13%	2%	4%	7%	1%	2%	3%
North Central	12%	8%	5%	2%	2%	2%	2%	2%	1%
South	24%	18%	10%	0%	1%	2%	1%	1%	1%
South Central	18%	12%	4%	3%	4%	5%	2%	2%	3%
West	38%	27%	11%	0%	2%	5%	1%	2%	3%
ERCOT	**15%**	**11%**	**5%**	**2%**	**2%**	**3%**	**2%**	**2%**	**2%**

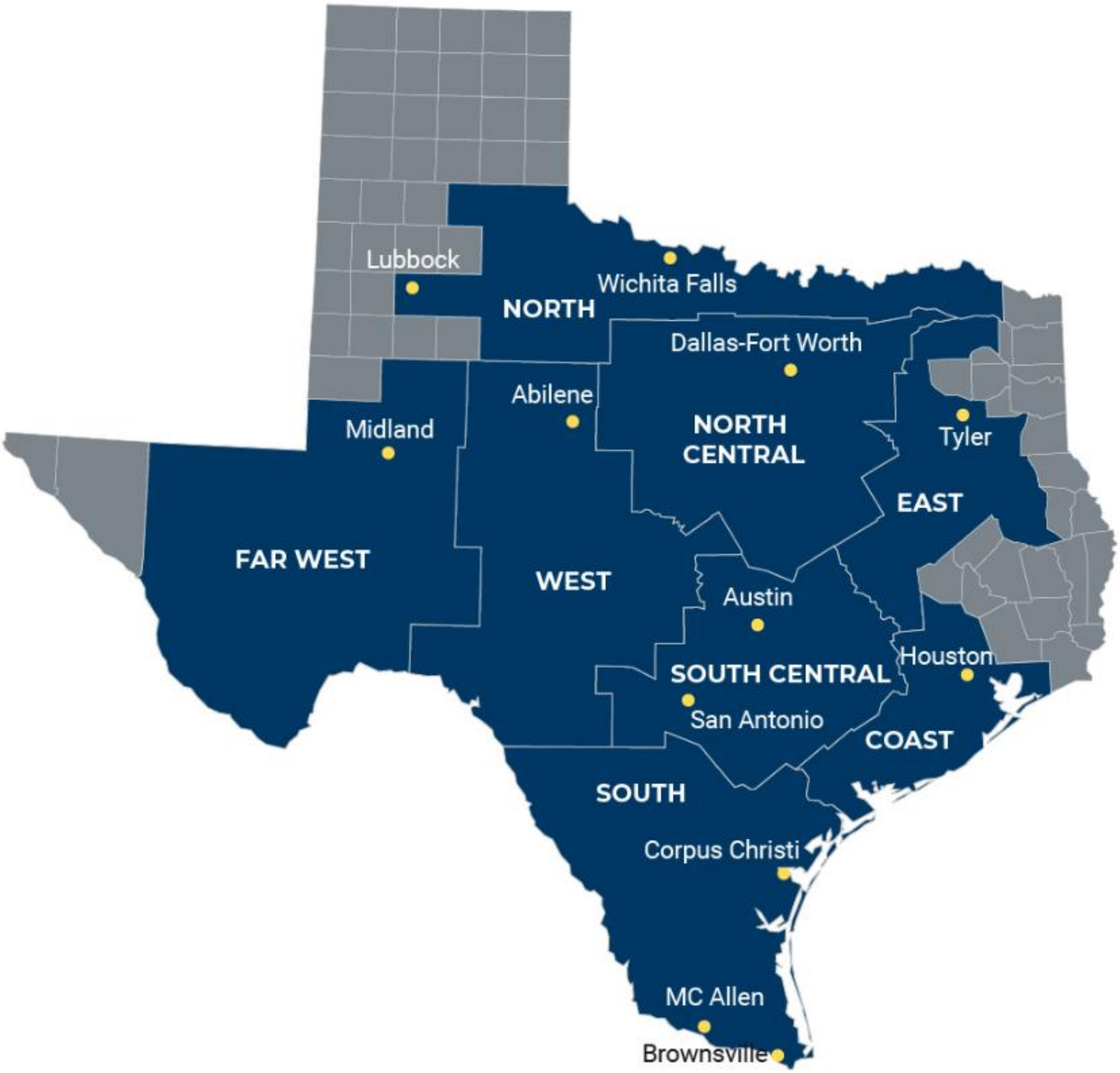
ERCOT Maps [11]

EXHIBIT 13: ERCOT LOAD ZONES



[11] https://www.ercot.com/news/mediakit/maps

EXHIBIT 14: ERCOT WEATHER ZONES



ERCOT Generation Additions

EXHIBIT 15: TOTAL ERCOT GENERATION ADDITIONS WITHOUT 765-KV LINES

	Existing Capacity	Capacity Additions								
GW	2025	2026 to 2030			2031 to 2038			2039 to 2050		
Technology	Actual	High	Mid	Low	High	Mid	Low	High	Mid	Low
Gas CC	37	20	9	0	31	16	8	15	24	15
Gas CT	8	21	18	10	16	16	26	14	14	16
Gas ST	11	0	0	0	1	1	1	0	0	0
Coal	14	0	0	0	0	0	0	0	0	0
Nuclear	5	0	0	0	0	0	0	0	0	0
Hydro	0	0	0	0	0	0	0	0	0	0
Oil	0	0	0	0	0	0	0	0	0	0
Onshore Wind	40	27	27	21	24	12	10	8	20	28
Offshore Wind	0	0	0	0	0	0	0	0	0	0
Solar PV	26	40	55	43	5	8	11	39	32	13
Biomass	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
Pumped Storage	0	0	0	0	0	0	0	0	0	0
Battery Storage	10	55	33	26	0	2	0	0	0	0
Peaker	1	0	0	0	0	0	0	0	0	0
Gass CC w/ CCS	0	0	0	0	0	0	0	0	0	0
Coal w/ CCS	0	0	0	0	0	0	0	0	0	0
Total	**151**	**163**	**141**	**100**	**77**	**55**	**55**	**77**	**90**	**72**

EXHIBIT 16: TOTAL ERCOT GENERATION ADDITIONS WITH THE PBRP

	Existing Capacity	Capacity Additions								
GW	2025	2026 to 2030			2031 to 2038			2039 to 2050		
Technology	Actual	High	Mid	Low	High	Mid	Low	High	Mid	Low
Gas CC	37	20	9	2	23	17	2	19	26	25
Gas CT	8	21	19	14	12	11	23	22	15	11
Gas ST	11	0	0	0	1	1	1	0	0	0
Coal	14	0	0	0	0	0	0	0	0	0
Nuclear	5	0	0	0	0	0	0	0	0	0
Hydro	0	0	0	0	0	0	0	0	0	0
Oil	0	0	0	0	0	0	0	0	0	0
Onshore Wind	40	27	27	21	24	12	10	8	20	28
Offshore Wind	0	0	0	0	0	0	0	0	0	0
Solar PV	26	37	53	41	10	7	5	39	34	22
Biomass	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
Pumped Storage	0	0	0	0	0	0	0	0	0	0
Battery Storage	10	53	31	26	0	2	0	0	0	0
Peaker	1	0	0	0	0	0	0	0	0	0
Gass CC w/ CCS	0	0	0	0	0	0	0	0	0	0
Coal w/ CCS	0	0	0	0	0	0	0	0	0	0
Total	**151**	**159**	**138**	**104**	**69**	**51**	**40**	**88**	**95**	**86**

EXHIBIT 17: TOTAL ERCOT GENERATION ADDITIONS WITH THE STEP

	Existing Capacity	Capacity Additions								
GW	2025	2026 to 2030			2031 to 2038			2039 to 2050		
Technology	Actual	High	Mid	Low	High	Mid	Low	High	Mid	Low
Gas CC	37	20	8	1	22	19	6	21	23	20
Gas CT	8	21	16	12	12	13	19	21	16	22
Gas ST	11	0	0	0	1	1	1	0	0	0
Coal	14	0	0	0	0	0	0	0	0	0
Nuclear	5	0	0	0	0	0	0	0	0	0
Hydro	0	0	0	0	0	0	0	0	0	0
Oil	0	0	0	0	0	0	0	0	0	0
Onshore Wind	40	27	25	19	24	9	9	8	24	31
Offshore Wind	0	0	0	0	0	0	0	0	0	0
Solar PV	26	37	54	37	9	9	8	35	23	21
Biomass	0	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0	0
Pumped Storage	0	0	0	0	0	0	0	0	0	0
Battery Storage	10	53	33	31	0	0	0	0	0	0
Peaker	1	0	0	0	0	0	0	0	0	0
Gass CC w/ CCS	0	0	0	0	0	0	0	0	0	0
Coal w/ CCS	0	0	0	0	0	0	0	0	0	0
Total	**151**	**159**	**136**	**99**	**68**	**50**	**42**	**85**	**87**	**94**

EXHIBIT 188: DIFFERENCE IN TOTAL ERCOT GENERATION ADDITIONS (NO 765-KV MINUS PBRP)

GW	2026 to 2030			2031 to 2038			2039 to 2050		
Technology	High	Mid	Low	High	Mid	Low	High	Mid	Low
Gas CC	0	0	-2	9	-1	6	-4	-1	-10
Gas CT	0	-1	-3	5	5	3	-8	-1	5
Gas ST	0	0	0	0	0	0	0	0	0
Coal	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0
Hydro	0	0	0	0	0	0	0	0	0
Oil	0	0	0	0	0	0	0	0	0
Onshore Wind	0	0	0	0	0	-1	0	0	0
Offshore Wind	0	0	0	0	0	0	0	0	0
Solar PV	3	2	1	-5	1	7	0	-2	-9
Biomass	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0
Pumped Storage	0	0	0	0	0	0	0	0	0
Battery Storage	1	2	0	0	0	0	0	0	0
Peaker	0	0	0	0	0	0	0	0	0
Gass CC w/ CCS	0	0	0	0	0	0	0	0	0
Coal w/ CCS	0	0	0	0	0	0	0	0	0
Total	**4**	**4**	**-4**	**8**	**4**	**15**	**-11**	**-4**	**-14**

EXHIBIT 199: DIFFERENCE IN TOTAL ERCOT GENERATION ADDITIONS (NO 765-KV MINUS STEP)

GW	2026 to 2030			2031 to 2038			2039 to 2050		
Technology	High	Mid	Low	High	Mid	Low	High	Mid	Low
Gas CC	0	1	-1	9	-3	2	-6	1	-5
Gas CT	0	2	-2	4	3	7	-7	-2	-6
Gas ST	0	0	0	0	0	0	0	0	0
Coal	0	0	0	0	0	0	0	0	0
Nuclear	0	0	0	0	0	0	0	0	0
Hydro	0	0	0	0	0	0	0	0	0
Oil	0	0	0	0	0	0	0	0	0
Onshore Wind	0	2	2	0	3	1	0	-4	-3
Offshore Wind	0	0	0	0	0	0	0	0	0
Solar PV	3	1	6	-4	-1	3	4	9	-8
Biomass	0	0	0	0	0	0	0	0	0
Geothermal	0	0	0	0	0	0	0	0	0
Other	0	0	0	0	0	0	0	0	0
Pumped Storage	0	0	0	0	0	0	0	0	0
Battery Storage	2	0	-5	0	2	0	0	0	0
Peaker	0	0	0	0	0	0	0	0	0
Gass CC w/ CCS	0	0	0	0	0	0	0	0	0
Coal w/ CCS	0	0	0	0	0	0	0	0	0
Total	**5**	**6**	**0**	**9**	**4**	**13**	**-9**	**4**	**-22**

EXHIBIT 20: ERCOT WEST GENERATION ADDITIONS THROUGH 2050

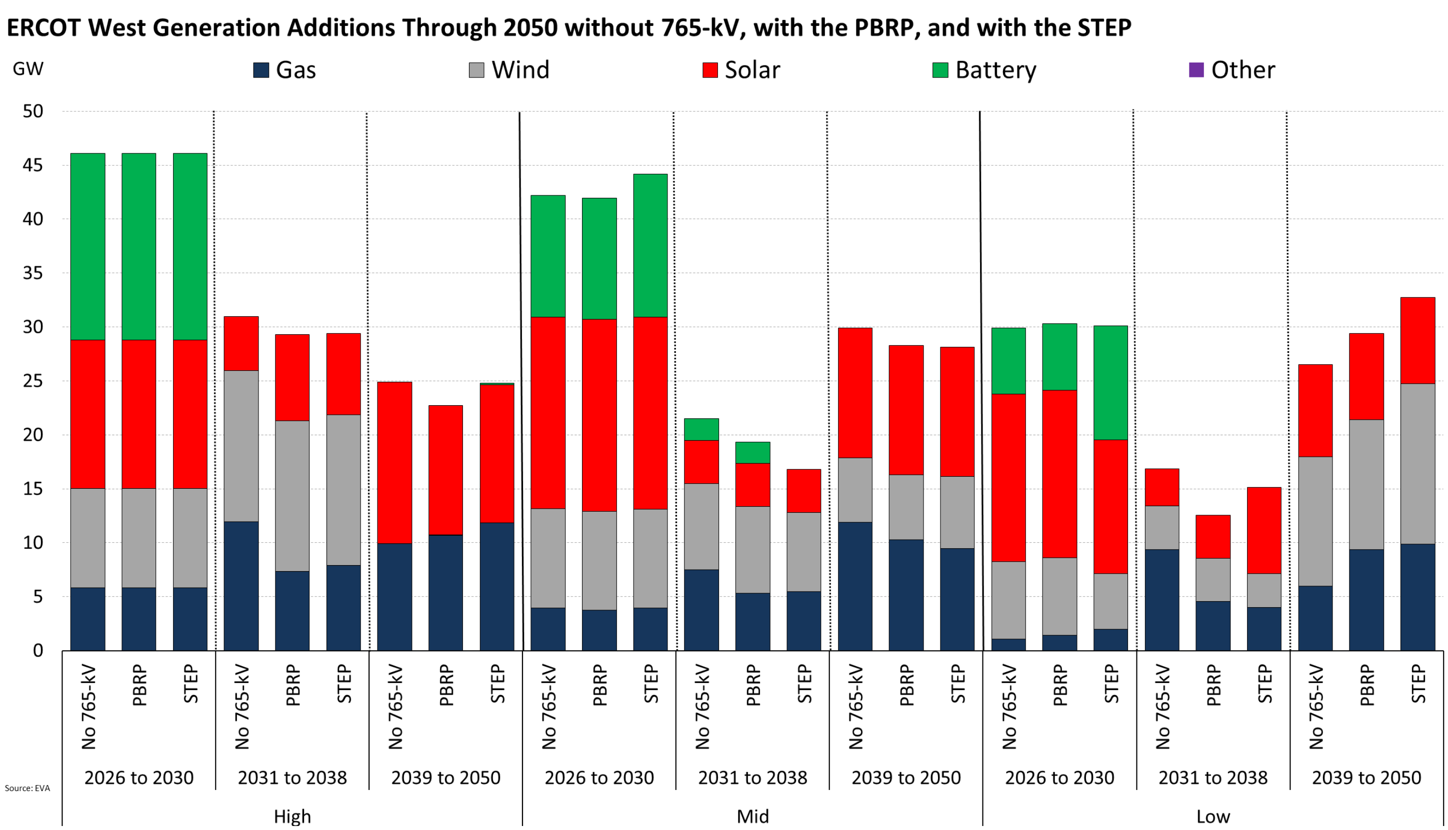


EXHIBIT 21: ERCOT NORTH GENERATION ADDITIONS THROUGH 2050

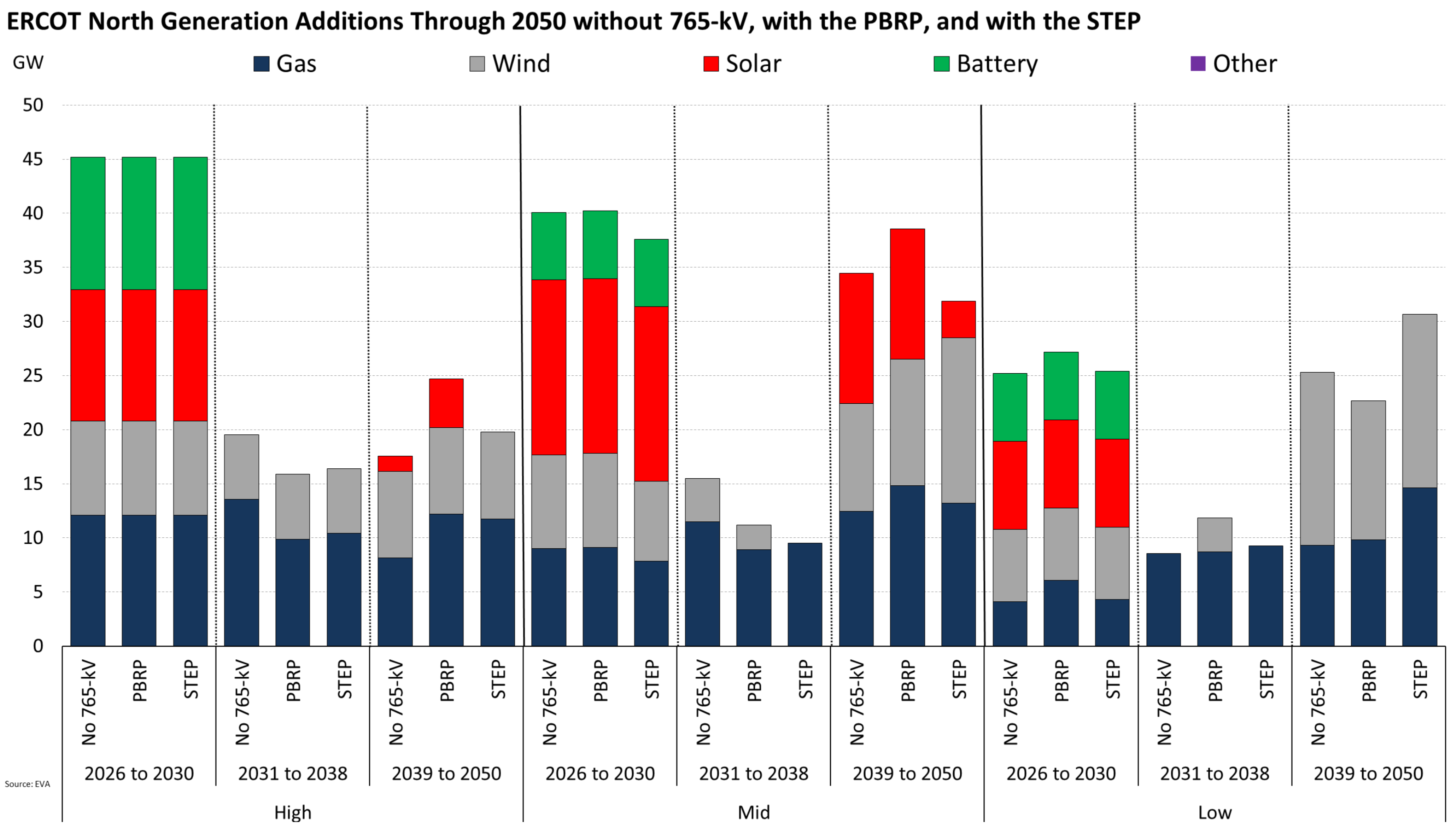


EXHIBIT 22: ERCOT SOUTH GENERATION ADDITIONS THROUGH 2050

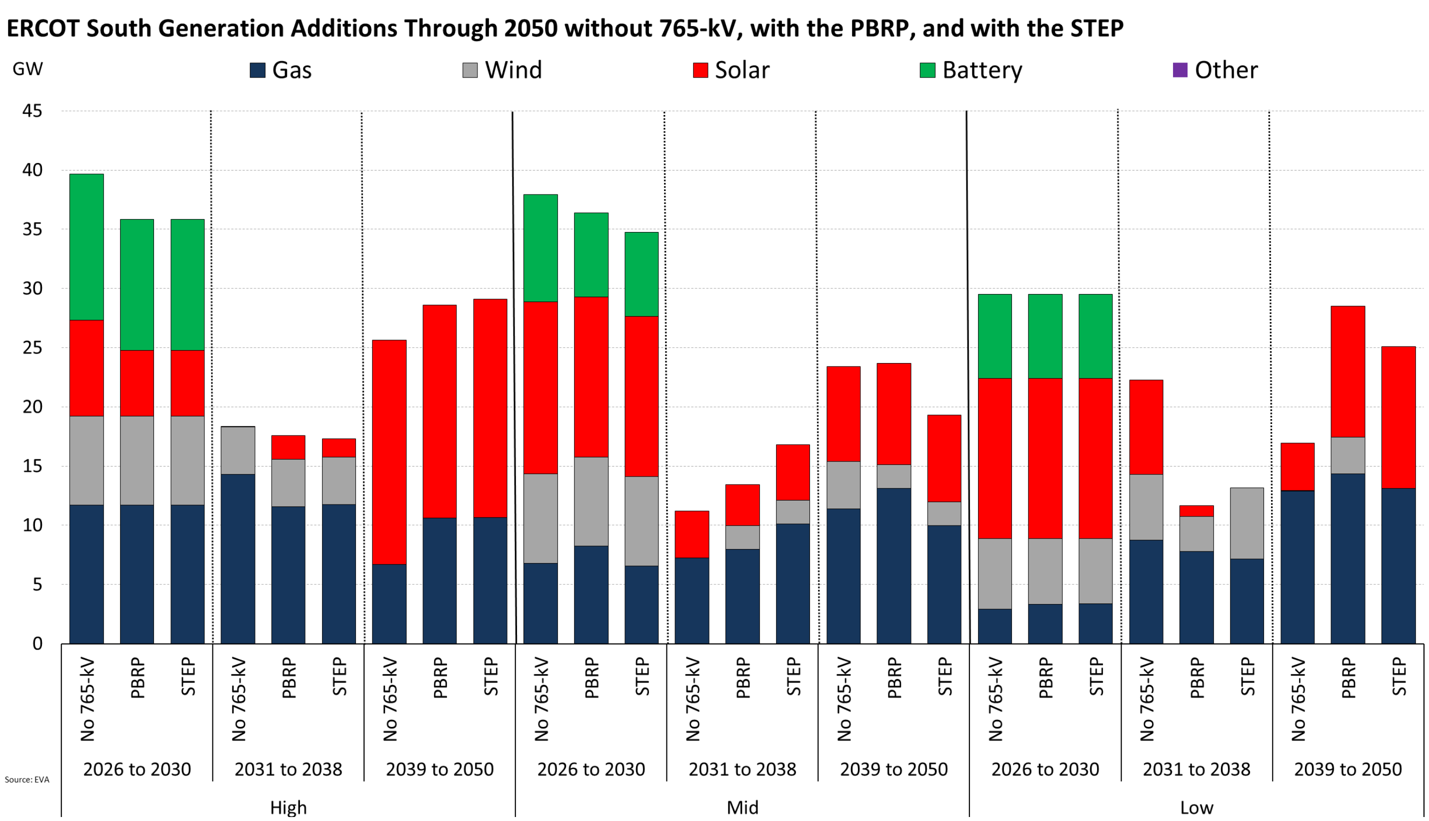
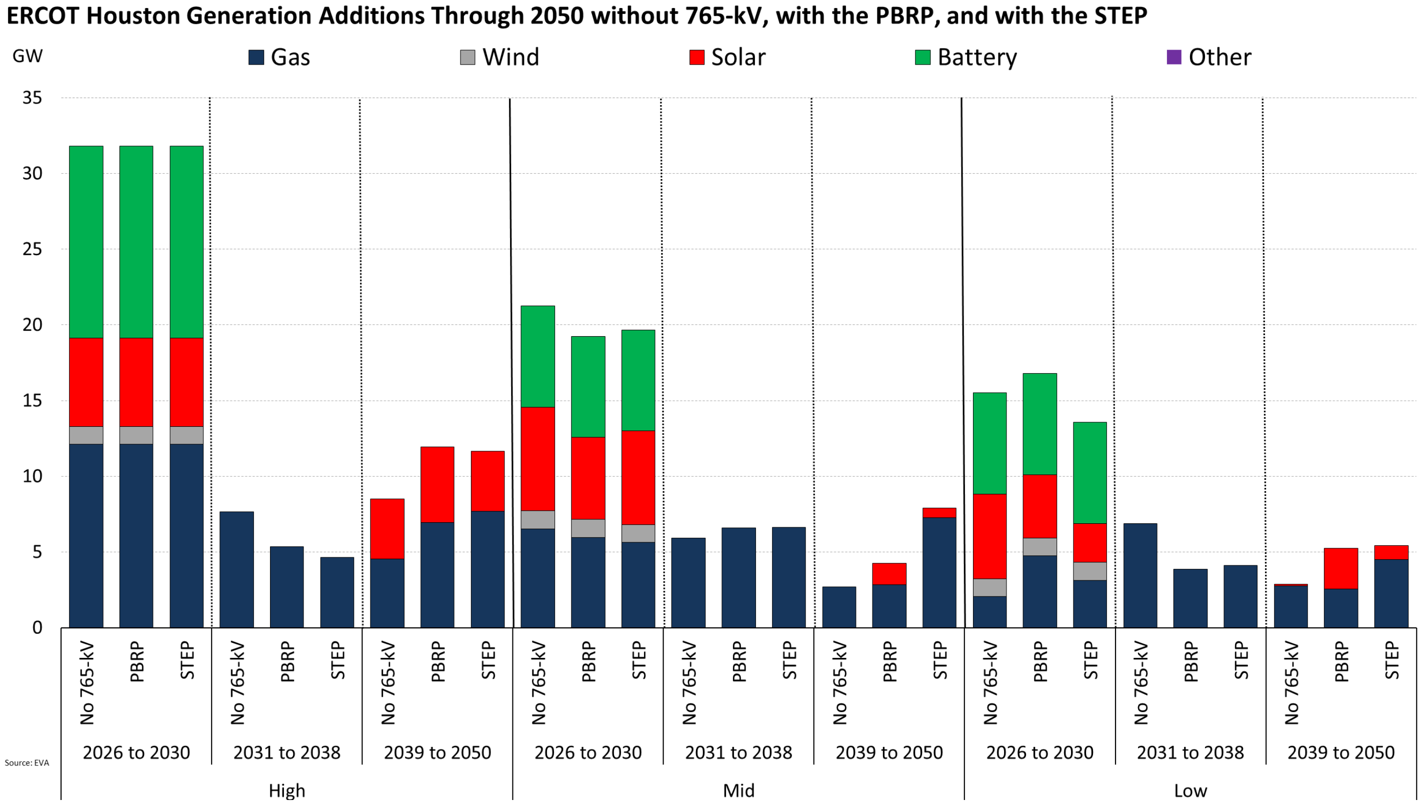


EXHIBIT 203: ERCOT HOUSTON GENERATION ADDITIONS THROUGH 2050



ERCOT Zones Capital Costs

EXHIBIT 214: ERCOT WEST ZONE CAPITAL COSTS

$B	No 765-kV			PBRP			Difference		
Time Period	High	Mid	Low	High	Mid	Low	High	Mid	Low
2026 to 2030	$82.38	$74.14	$52.07	$82.38	$73.83	$52.83	$0.00	$0.31	-$0.76
2031 to 2038	$67.50	$48.84	$33.58	$61.71	$45.04	$26.06	$5.79	$3.80	$7.51
2039 to 2050	$64.01	$68.87	$59.36	$59.64	$66.84	$63.73	$4.38	$2.03	-$4.37
Total	**$213.89**	**$191.85**	**$145.00**	**$203.72**	**$185.72**	**$142.62**	**$10.17**	**$6.13**	**$2.38**

$B	No 765-kV			STEP			Difference		
Time Period	High	Mid	Low	High	Mid	Low	High	Mid	Low
2026 to 2030	$82.38	$74.14	$52.07	$82.38	$77.68	$53.44	$0.00	-$3.54	-$1.38
2031 to 2038	$67.50	$48.84	$33.58	$61.93	$40.96	$30.52	$5.57	$7.88	$3.05
2039 to 2050	$64.01	$68.87	$59.36	$63.07	$66.20	$68.07	$0.94	$2.66	-$8.71
Total	**$213.89**	**$191.85**	**$145.00**	**$207.38**	**$184.84**	**$152.04**	**$6.51**	**$7.01**	**-$7.04**

EXHIBIT 225: ERCOT NORTH ZONE CAPITAL COSTS

$B	No 765-kV			PBRP			Difference		
Time Period	High	Mid	Low	High	Mid	Low	High	Mid	Low
2026 to 2030	$82.62	$71.46	$45.22	$82.62	$71.57	$48.83	$0.00	-$0.12	-$3.61
2031 to 2038	$46.64	$35.65	$19.50	$41.66	$29.91	$24.61	$4.98	$5.74	-$5.12
2039 to 2050	$54.00	$75.53	$53.25	$62.74	$79.25	$52.33	-$8.74	-$3.72	$0.92
Total	**$183.27**	**$182.64**	**$153.45**	**$187.03**	**$180.74**	**$158.95**	**-$3.76**	**$1.90**	**-$5.50**

$B	No 765-kV			STEP			Difference		
Time Period	High	Mid	Low	High	Mid	Low	High	Mid	Low
2026 to 2030	$82.62	$71.46	$45.22	$82.62	$66.30	$45.71	$0.00	$5.15	-$0.49
2031 to 2038	$46.64	$35.65	$19.50	$42.39	$24.54	$21.07	$4.25	$11.11	-$1.57
2039 to 2050	$54.00	$75.53	$53.25	$55.12	$68.13	$62.10	-$1.12	$7.40	-$8.85
Total	**$183.27**	**$182.64**	**$153.45**	**$180.13**	**$158.97**	**$128.87**	**$3.13**	**$23.66**	**-$10.91**

EXHIBIT 236: ERCOT SOUTH ZONE CAPITAL COSTS

$B	No 765-kV			PBRP			Difference		
Time Period	High	Mid	Low	High	Mid	Low	High	Mid	Low
2026 to 2030	$73.10	$67.39	$51.38	$66.76	$64.92	$51.36	$6.34	$2.47	$0.02
2031 to 2038	$44.05	$28.13	$41.67	$42.26	$32.13	$23.78	$1.80	-$3.99	$17.88
2039 to 2050	$58.66	$53.41	$39.94	$61.37	$52.48	$55.76	-$2.71	$0.94	-$15.82
Total	**$175.82**	**$148.94**	**$132.99**	**$170.39**	**$149.52**	**$130.91**	**$5.43**	**-$0.58**	**$2.08**

$B	No 765-kV			STEP			Difference		
Time Period	High	Mid	Low	High	Mid	Low	High	Mid	Low
2026 to 2030	$73.10	$67.39	$51.38	$66.76	$61.69	$51.63	$6.34	$5.70	-$0.25
2031 to 2038	$44.05	$28.13	$41.67	$41.70	$39.26	$29.74	$2.35	-$11.12	$11.93
2039 to 2050	$58.66	$53.41	$39.94	$62.24	$47.94	$50.46	-$3.58	$5.47	-$10.52
Total	**$175.82**	**$148.94**	**$132.99**	**$170.70**	**$148.90**	**$131.83**	**$5.12**	**$0.04**	**$1.16**

EXHIBIT 247: ERCOT HOUSTON ZONE CAPITAL COSTS

$B	No 765-kV			PBRP			Difference		
Time Period	High	Mid	Low	High	Mid	Low	High	Mid	Low
2026 to 2030	$58.28	$37.48	$26.99	$58.28	$34.11	$29.74	$0.00	$3.36	-$2.75
2031 to 2038	$20.43	$14.94	$15.07	$17.59	$16.31	$9.07	$2.84	-$1.36	$6.00
2039 to 2050	$25.73	$12.68	$10.49	$29.57	$14.98	$13.91	-$3.84	-$2.30	-$3.42
Total	**$104.44**	**$65.10**	**$52.55**	**$105.44**	**$65.40**	**$52.72**	**-$1.00**	**-$0.30**	**-$0.17**

$B	No 765-kV			STEP			Difference		
Time Period	High	Mid	Low	High	Mid	Low	High	Mid	Low
2026 to 2030	$58.28	$37.48	$26.99	$58.28	$35.52	$24.23	$0.00	$1.96	$2.76
2031 to 2038	$20.43	$14.94	$15.07	$16.32	$16.07	$9.42	$4.12	-$1.12	$5.65
2039 to 2050	$25.73	$12.68	$10.49	$29.13	$19.40	$13.41	-$3.41	-$6.72	-$2.92
Total	**$104.44**	**$65.10**	**$52.55**	**$103.73**	**$70.99**	**$47.06**	**$0.71**	**-$5.89**	**$5.49**

ERCOT Zones System Energy Costs

EXHIBIT 258: ERCOT WEST ZONE SYSTEM ENERGY COSTS

$B	No 765-kV			PBRP			Difference		
Time Period	High	Mid	Low	High	Mid	Low	High	Mid	Low
2026 to 2030	$62.18	$46.14	$31.07	$62.82	$45.90	$31.79	-$0.64	$0.24	-$0.72
2031 to 2038	$136.90	$114.20	$81.96	$124.64	$108.38	$73.68	$12.26	$5.82	$8.29
2039 to 2050	$285.01	$232.14	$172.40	$264.72	$216.25	$168.51	$20.29	$15.89	$3.89
Total	**$484.09**	**$392.48**	**$285.43**	**$452.17**	**$370.53**	**$273.97**	**$31.92**	**$21.95**	**$11.46**

$B	No 765-kV			STEP			Difference		
Time Period	High	Mid	Low	High	Mid	Low	High	Mid	Low
2026 to 2030	$62.18	$46.14	$31.07	$62.60	$46.66	$31.33	-$0.42	-$0.52	-$0.26
2031 to 2038	$136.90	$114.20	$81.96	$131.69	$109.02	$78.26	$5.21	$5.17	$3.70
2039 to 2050	$285.01	$232.14	$172.40	$270.99	$220.85	$167.62	$14.02	$11.29	$4.78
Total	**$484.09**	**$392.48**	**$285.43**	**$465.29**	**$376.53**	**$277.22**	**$18.80**	**$15.95**	**$8.22**

EXHIBIT 269: ERCOT NORTH ZONE SYSTEM ENERGY COSTS

$B	No 765-kV			PBRP			Difference		
Time Period	High	Mid	Low	High	Mid	Low	High	Mid	Low
2026 to 2030	$142.86	$92.00	$55.78	$143.62	$92.27	$56.23	-$0.76	-$0.27	-$0.45
2031 to 2038	$190.58	$156.56	$107.91	$205.47	$160.74	$118.09	-$14.89	-$4.18	-$10.18
2039 to 2050	$361.66	$288.30	$215.15	$382.77	$300.36	$235.67	-$21.11	-$12.06	-$20.52
Total	**$695.10**	**$536.85**	**$378.83**	**$731.86**	**$553.37**	**$409.99**	**-$36.76**	**-$16.51**	**-$31.15**

$B	No 765-kV			STEP			Difference		
Time Period	High	Mid	Low	High	Mid	Low	High	Mid	Low
2026 to 2030	$142.86	$92.00	$55.78	$142.95	$90.77	$55.37	-$0.09	$1.23	$0.41
2031 to 2038	$190.58	$156.56	$107.91	$203.37	$160.84	$117.25	-$12.78	-$4.28	-$9.34
2039 to 2050	$361.66	$288.30	$215.15	$368.60	$296.84	$222.51	-$6.94	-$8.53	-$7.36
Total	**$695.10**	**$536.85**	**$378.83**	**$714.91**	**$548.45**	**$395.12**	**-$19.81**	**-$11.59**	**-$16.29**

EXHIBIT 30: ERCOT SOUTH ZONE SYSTEM ENERGY COSTS

$B	No 765-kV			PBRP			Difference		
Time Period	High	Mid	Low	High	Mid	Low	High	Mid	Low
2026 to 2030	$85.29	$54.82	$33.78	$83.88	$55.05	$33.49	$1.41	-$0.22	$0.28
2031 to 2038	$143.27	$106.99	$76.95	$146.36	$114.33	$77.91	-$3.10	-$7.34	-$0.96
2039 to 2050	$282.44	$208.25	$165.49	$289.58	$222.37	$168.04	-$7.14	-$14.12	-$2.55
Total	**$511.00**	**$370.07**	**$276.22**	**$519.83**	**$391.76**	**$279.44**	**-$8.82**	**-$21.69**	**-$3.22**

$B	No 765-kV			STEP			Difference		
Time Period	High	Mid	Low	High	Mid	Low	High	Mid	Low
2026 to 2030	$85.29	$54.82	$33.78	$85.02	$53.55	$34.64	$0.27	$1.28	-$0.87
2031 to 2038	$143.27	$106.99	$76.95	$150.07	$119.88	$80.97	-$6.80	-$12.89	-$4.02
2039 to 2050	$282.44	$208.25	$165.49	$285.92	$238.70	$161.08	-$3.48	-$30.45	$4.41
Total	**$511.00**	**$370.07**	**$276.22**	**$521.01**	**$412.13**	**$276.70**	**-$10.01**	**-$42.06**	**-$0.48**

EXHIBIT 31: ERCOT HOUSTON ZONE SYSTEM ENERGY COSTS

$B	No 765-kV			PBRP			Difference		
Time Period	High	Mid	Low	High	Mid	Low	High	Mid	Low
2026 to 2030	$92.18	$49.38	$30.26	$92.63	$50.22	$28.83	-$0.45	-$0.84	$1.43
2031 to 2038	$110.42	$73.10	$53.55	$108.76	$70.52	$57.15	$1.66	$2.58	-$3.60
2039 to 2050	$182.88	$122.13	$100.50	$182.28	$125.96	$101.44	$0.60	-$3.82	-$0.93
Total	**$385.48**	**$244.61**	**$184.31**	**$383.67**	**$246.69**	**$187.42**	**$1.81**	**-$2.08**	**-$3.11**

$B	No 765-kV			STEP			Difference		
Time Period	High	Mid	Low	High	Mid	Low	High	Mid	Low
2026 to 2030	$92.18	$49.38	$30.26	$92.52	$49.92	$29.24	-$0.34	-$0.54	$1.01
2031 to 2038	$110.42	$73.10	$53.55	$108.99	$72.29	$55.85	$1.43	$0.81	-$2.30
2039 to 2050	$182.88	$122.13	$100.50	$182.11	$121.25	$95.30	$0.77	$0.89	$5.20
Total	**$385.48**	**$244.61**	**$184.31**	**$383.62**	**$243.46**	**$180.39**	**$1.86**	**$1.15**	**$3.92**

EXHIBIT 272: ERCOT OTHER ZONES SYSTEM ENERGY COSTS

$B	No 765-kV			PBRP			Difference		
Time Period	High	Mid	Low	High	Mid	Low	High	Mid	Low
2026 to 2030	$30.74	$19.70	$12.48	$30.90	$19.83	$11.80	-$0.15	-$0.13	$0.68
2031 to 2038	$24.43	$20.15	$17.36	$26.50	$20.97	$19.23	-$2.07	-$0.82	-$1.87
2039 to 2050	$33.35	$28.50	$26.91	$36.11	$29.82	$28.19	-$2.76	-$1.33	-$1.28
Total	**$88.53**	**$68.34**	**$56.75**	**$93.50**	**$70.62**	**$59.22**	**-$4.97**	**-$2.28**	**-$2.47**

$B	No 765-kV			STEP			Difference		
Time Period	High	Mid	Low	High	Mid	Low	High	Mid	Low
2026 to 2030	$30.74	$19.70	$12.48	$30.31	$20.01	$12.16	$0.44	-$0.31	$0.32
2031 to 2038	$24.43	$20.15	$17.36	$25.99	$22.81	$18.66	-$1.56	-$2.66	-$1.30
2039 to 2050	$33.35	$28.50	$26.91	$35.15	$31.81	$26.38	-$1.80	-$3.32	$0.53
Total	**$88.53**	**$68.34**	**$56.75**	**$91.45**	**$74.63**	**$57.20**	**-$2.92**	**-$6.29**	**-$0.46**

Power Prices

EXHIBIT 283: POWER PRICES ($/MWH) BY ERCOT LOAD ZONE

Year	Demand	765-kV Lines	West	North	South	Houston	CPS	AEN	LCRA	BEPC	Rayburn
2025	Actual		$42.72	$33.41	$33.33	$34.57	$37.10	$36.95	$38.18	$33.41	$33.69
2030	High	No	$78.43	$73.96	$74.32	$76.41	$75.51	$75.51	$75.51	$74.34	$75.15
2030	High	PBRP	$78.13	$73.54	$73.94	$76.44	$75.11	$75.11	$75.10	$73.96	$74.71
2030	High	STEP	$77.78	$73.78	$74.79	$76.44	$75.33	$75.33	$75.33	$74.20	$74.95
2030	Mid	No	$67.59	$69.31	$67.56	$60.87	$69.01	$69.01	$69.00	$69.36	$70.80
2030	Mid	PBRP	$67.46	$69.32	$67.34	$59.15	$68.70	$68.70	$68.69	$69.36	$70.72
2030	Mid	STEP	$65.25	$68.40	$68.41	$55.06	$69.73	$69.73	$69.73	$68.42	$69.73
2030	Low	No	$53.80	$50.09	$50.48	$52.41	$51.67	$51.67	$51.65	$49.99	$51.27
2030	Low	PBRP	$53.98	$54.14	$52.15	$53.33	$51.32	$51.32	$51.28	$49.93	$51.44
2030	Low	STEP	$53.80	$50.75	$50.63	$56.04	$51.91	$51.91	$51.90	$50.64	$52.02
2038	High	No	$68.88	$64.87	$64.97	$66.70	$66.77	$66.38	$66.38	$65.00	$66.27
2038	High	PBRP	$66.87	$66.95	$67.17	$64.62	$68.75	$68.50	$68.49	$67.17	$68.26
2038	High	STEP	$68.17	$66.89	$68.56	$64.21	$68.66	$68.41	$68.41	$67.11	$68.18
2038	Mid	No	$66.61	$60.53	$60.66	$60.91	$61.99	$61.99	$61.99	$60.66	$61.86
2038	Mid	PBRP	$64.20	$62.77	$62.82	$58.63	$64.19	$64.19	$64.19	$62.82	$64.14
2038	Mid	STEP	$65.30	$66.78	$63.86	$57.04	$68.21	$68.20	$68.20	$66.76	$68.22
2038	Low	No	$59.49	$55.70	$55.53	$57.71	$56.84	$56.84	$56.81	$55.52	$57.02
2038	Low	PBRP	$56.81	$57.44	$58.54	$55.78	$58.73	$58.73	$58.72	$57.44	$58.72
2038	Low	STEP	$63.70	$55.90	$55.86	$57.02	$57.09	$57.09	$57.09	$55.86	$57.13
2050	High	No	$73.89	$69.77	$69.90	$72.04	$72.55	$71.19	$71.25	$69.97	$71.04
2050	High	PBRP	$71.98	$71.68	$71.95	$69.90	$74.68	$73.26	$73.34	$72.03	$73.00
2050	High	STEP	$77.76	$73.23	$73.45	$79.09	$76.26	$74.81	$74.88	$73.52	$74.60
2050	Mid	No	$69.68	$64.61	$64.90	$65.21	$66.90	$66.14	$66.14	$64.93	$65.85
2050	Mid	PBRP	$67.02	$67.09	$67.22	$65.59	$69.43	$68.64	$68.64	$67.23	$68.50
2050	Mid	STEP	$63.82	$73.35	$71.13	$59.40	$74.76	$73.91	$73.92	$72.46	$73.81
2050	Low	No	$60.38	$56.71	$56.69	$58.28	$58.12	$57.85	$57.83	$56.70	$57.87
2050	Low	PBRP	$57.37	$58.37	$59.82	$56.58	$60.05	$59.71	$59.71	$58.53	$59.55
2050	Low	STEP	$57.91	$57.60	$57.77	$66.53	$59.25	$58.99	$58.98	$57.77	$58.82