American Petroleum Institute Southeast Report

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CRA Charles River Associates

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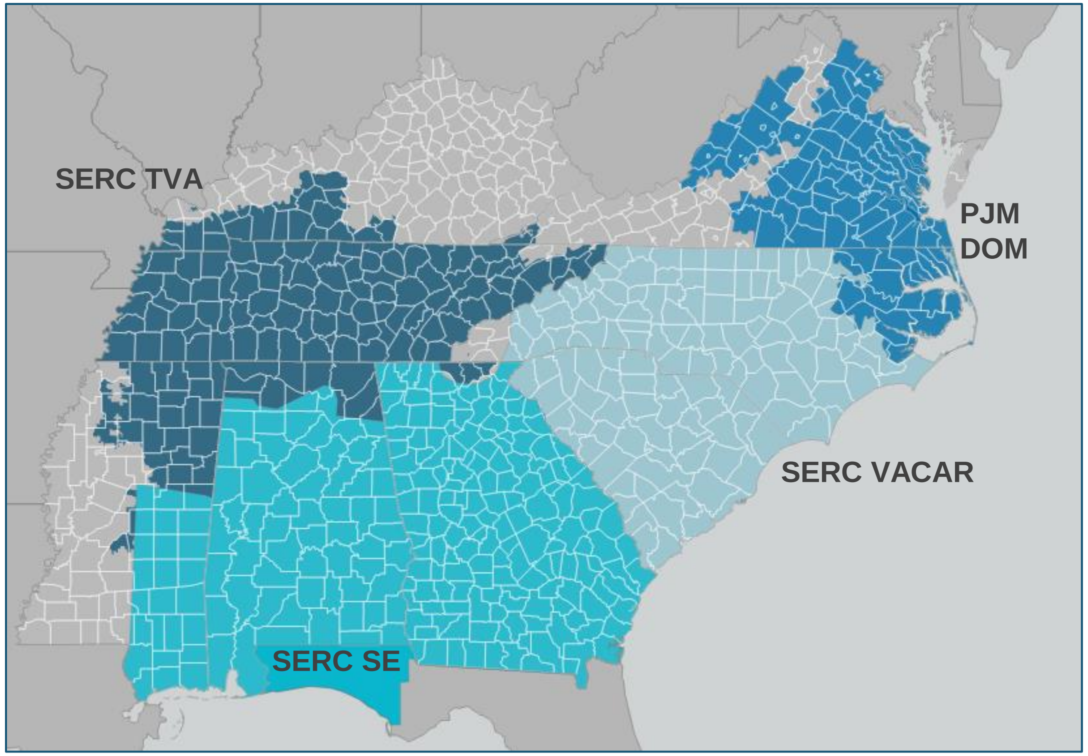
Without new natural gas pipeline capacity in the Southeast region of the US, fuel and electric power costs are likely to rise

Map of Electric Service Territories in CRA Analysis*



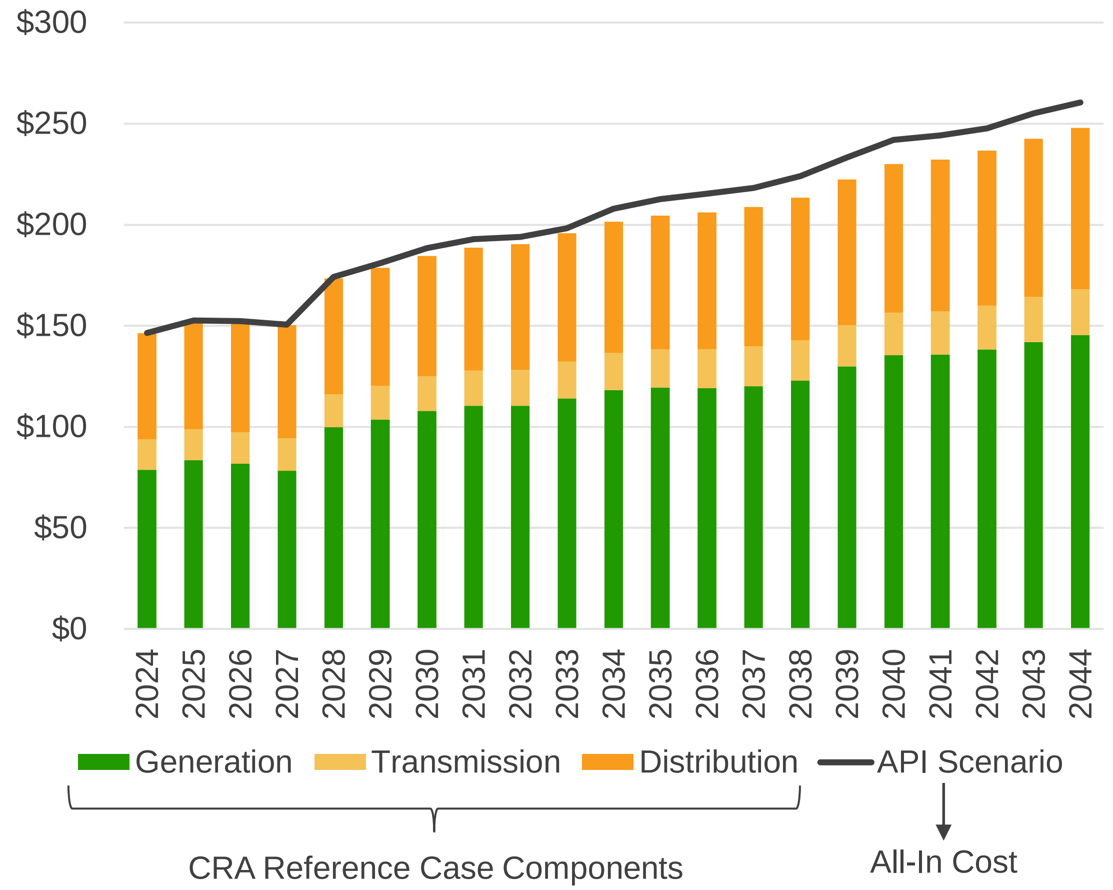
** Source: S&P Global*
*** Assuming average monthly consumption of 1,000 kWh*

Cost Increase without Expanded Natural Gas Pipeline Capacity

Region	Category	2035	2044
PJM DOM	Local Gas Price Increase (%)	12.1%	19.6%
	Electric Generation Cost Increase (%)	6.9%	8.6%
	Total Electric Service Cost Increase (%)	4.0%	5.0%
	Annual Electric Bill Impact ($)**	**+$98**	**+$150**
SERC SE	Local Gas Price Increase (%)	9.8%	15.5%
	Electric Generation Cost Increase (%)	10.3%	12.8%
	Total Electric Service Cost Increase (%)	5.4%	5.9%
	Annual Electric Bill Impact ($)**	**+$115**	**+$137**
SERC VACAR	Local Gas Price Increase (%)	12.1%	19.6%
	Electric Generation Cost Increase (%)	2.7%	9.9%
	Total Electric Service Cost Increase (%)	1.6%	5.7%
	Annual Electric Bill Impact ($)**	**+$37**	**+$155**
SERC TVA	Local Gas Price Increase (%)	8.0%	12.9%
	Electric Generation Cost Increase (%)	0.6%	3.3%
	Total Electric Service Cost Increase (%)	0.3%	1.3%
	Annual Electric Bill Impact ($)**	**+$5**	**+$25**

Without new gas pipeline capacity in the PJM-DOM region, electric bills are projected to be ~$150 higher annually by 2044

PJM DOM Monthly Retail Electricity Cost Projections ($/MWh)



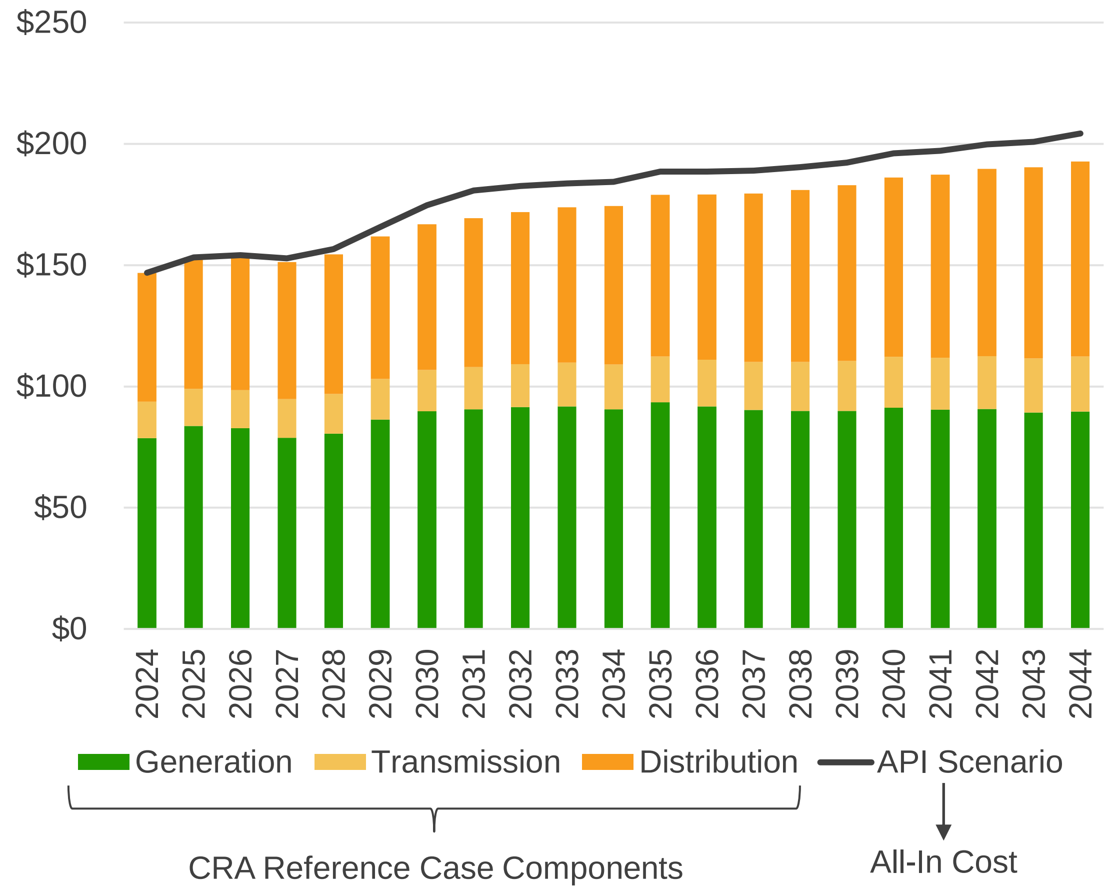
Region	Cost increase without new natural gas pipeline capacity	2035	2044
PJM DOM	Local Gas Price Increase (%)	12.1%	19.6%
	Electric Generation Cost Increase (%)	6.9%	8.6%
	Total Electric Service Cost Increase (%)	4.0%	5.0%
	Annual Electric Bill Impact ($)*	**+$98**	**+$150**

- Gas prices in the API scenario are expected to go up as a result of growing regional demand and an inability to increase access to low-cost natural gas in the Appalachian region.
- Very strong electric demand growth in the region will result in a need for new thermal and renewable power plants. In the API scenario, higher gas prices are expected to raise the variable cost of electric generation and shift some new capacity additions to higher-cost intermittent renewables and imports from other regions.

** Assuming average monthly consumption of 1,000 kWh*

Without new gas pipeline capacity in the SERC-SE region, electric bills are projected to be ~$137 higher annually by 2044

SERC SE Monthly Retail Electricity Cost Projections ($/MWh)



Region	Cost increase without new natural gas pipeline capacity	2035	2044
SERC SE	Local Gas Price Increase (%)	9.8%	15.5%
	Electric Generation Cost Increase (%)	10.3%	12.8%
	Total Electric Service Cost Increase (%)	5.4%	5.9%
	Annual Electric Bill Impact ($)*	**+$115**	**+$137**

- Gas prices in the API scenario are expected to go up as a result of growing near term electric and industrial demand in addition to limitations placed on expansion of the main regional gas pipeline.
- Electric demand growth in the region will result in a need for new thermal and renewable power plants. In the API scenario, higher gas prices are expected to raise the variable cost of electric generation and shift some new capacity additions to more expensive solar, battery storage, and imports.

** Assuming average monthly consumption of 1,000 kWh*

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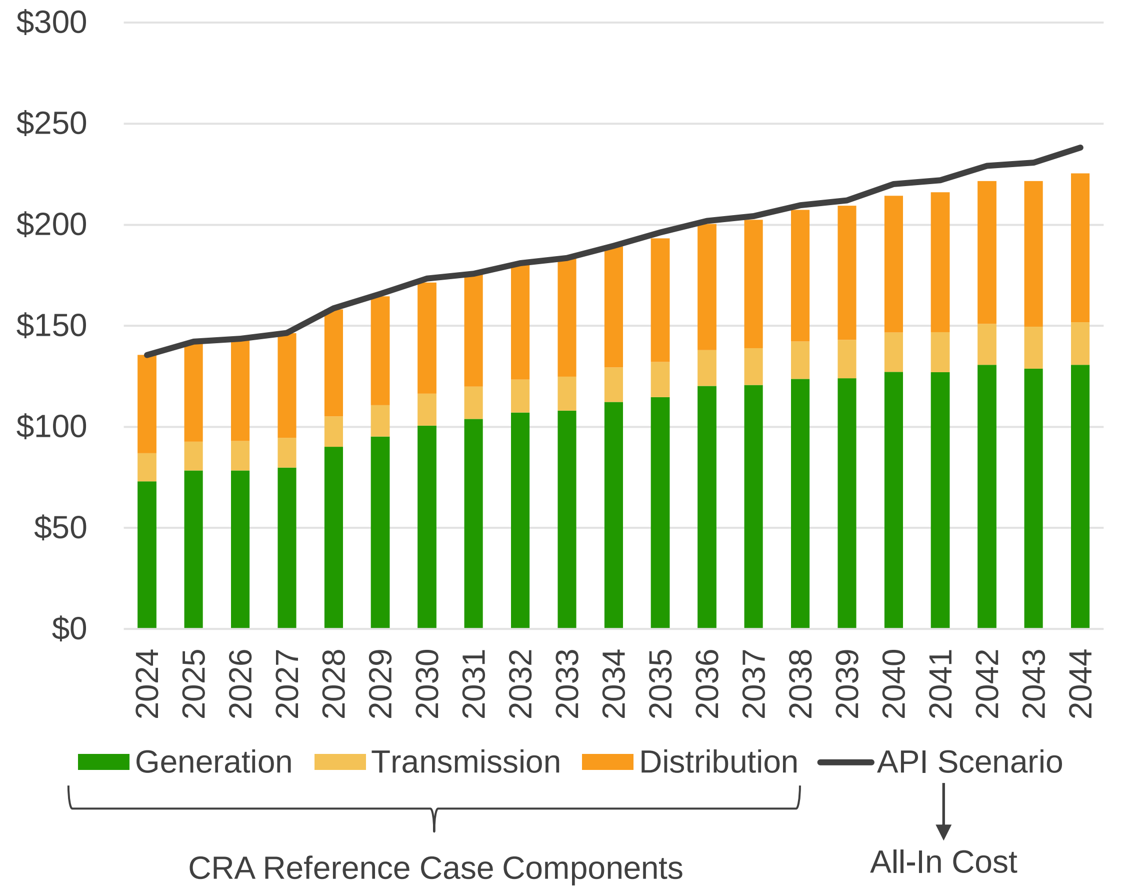
Without new gas pipeline capacity in the SERC-VACAR region, electric bills are projected to be ~$155 higher annually by 2044

SERC VACAR Monthly Retail Electricity Cost Projections ($/MWh)



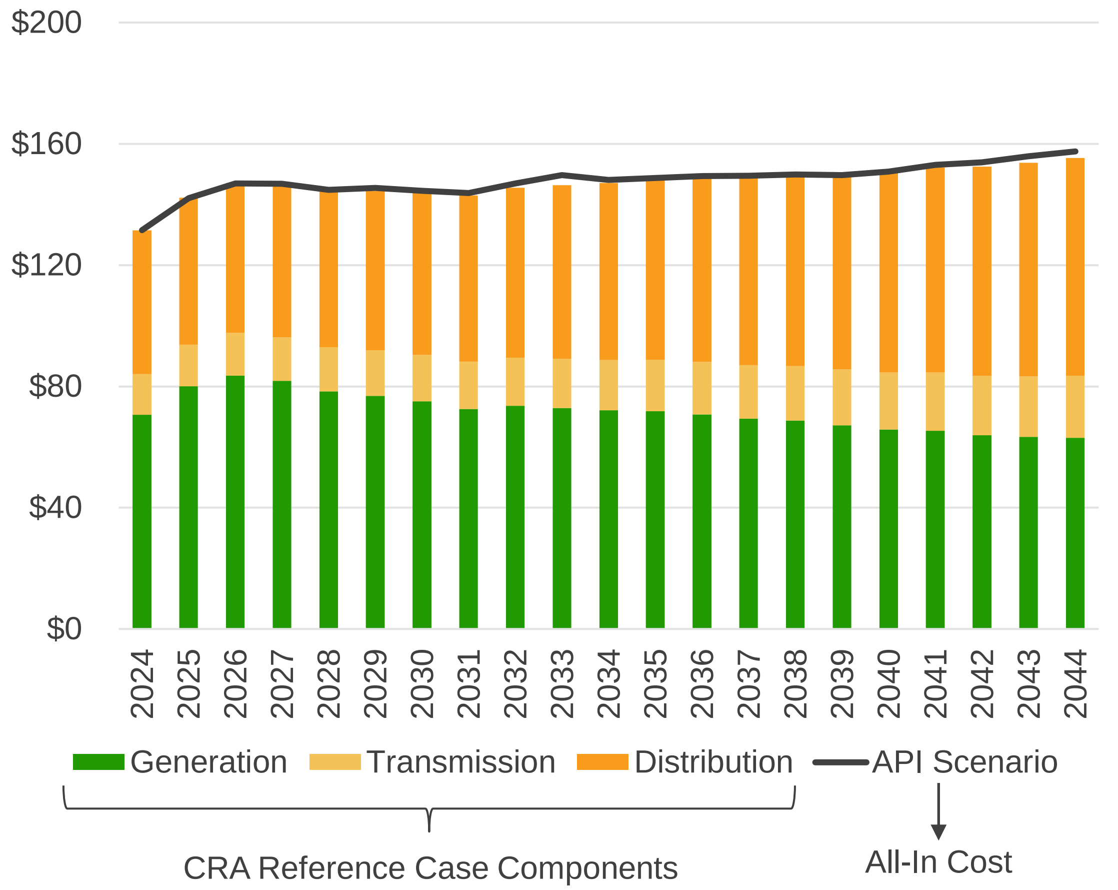
Region	Cost increase without new natural gas pipeline capacity	2035	2044
SERC VACAR	Local Gas Price Increase (%)	12.1%	19.6%
	Electric Generation Cost Increase (%)	2.7%	9.9%
	Total Electric Service Cost Increase (%)	1.6%	5.7%
	Annual Electric Bill Impact ($)*	**+$37**	**+$155**

- Gas prices in the API scenario are expected to go up as a result of sustained electric and industrial demand in addition to a limits on access to more natural gas from Texas or Appalachia.
- Electric demand growth in the region will result in a need for new thermal and renewable power plants. In the API scenario, higher gas prices are expected to raise the variable cost of electric generation and shift some new capacity additions from combined cycle gas to higher-cost small modular nuclear reactors (SMRs).

** Assuming average monthly consumption of 1,000 kWh*

Without new gas pipeline capacity in the SERC-TVA region, electric bills are only projected to be ~$25 higher annually by 2044

SERC TVA Monthly Retail Electricity Cost Projections ($/MWh)



Region	Cost increase without new natural gas pipeline capacity	2035	2044
SERC TVA	Local Gas Price Increase (%)	8.0%	12.9%
	Electric Generation Cost Increase (%)	0.6%	3.3%
	Total Electric Service Cost Increase (%)	0.3%	1.3%
	Annual Electric Bill Impact ($)*	**+$5**	**+$25**

- Gas prices in the API scenario are expected to go up as a result of limiting the expansion of pipeline capacity linking the main gas trading hub in Louisiana to natural gas production in Appalachia.
- Electric demand growth is projected by TVA to be relatively flat, meaning that fewer new capacity additions are needed relative to other regions. Additionally, TVA can offset the higher generation costs by exporting less and relying more upon its nuclear and hydroelectric capacity.

** Assuming average monthly consumption of 1,000 kWh*

CRA's Reference case reflects its expected future for US energy; the API scenario reflects a hostility to new gas pipeline capacity

CRA Reference Case

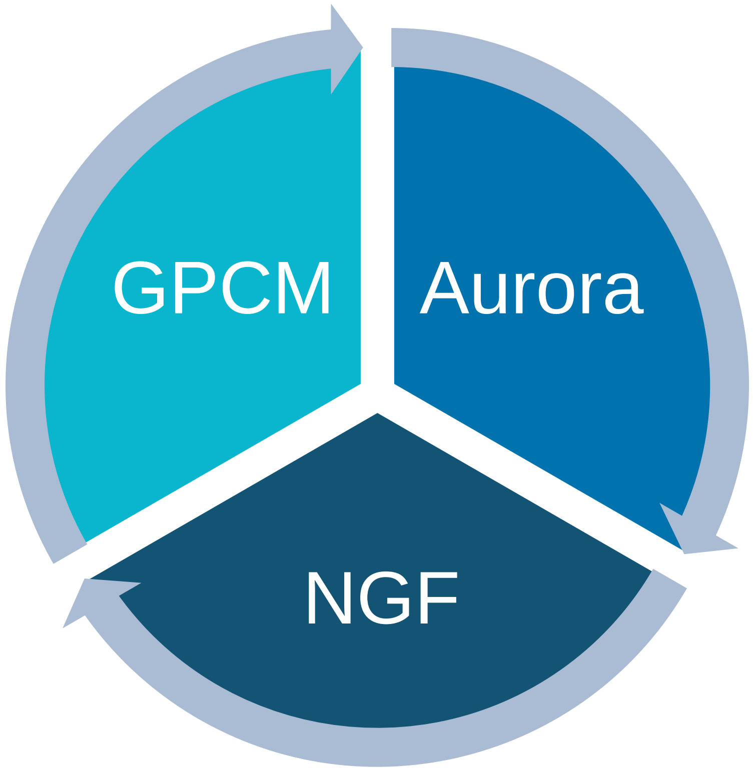
- CRA constructed a Reference Case, which includes:
  - Growing electricity demand driven by population growth, electrification, and new commercial data center demand,
  - Increasing natural gas production and production costs to meet liquified natural gas (LNG) exports in the 2020s and rising natural gas production costs as proven reserves are depleted in the 2030s,
  - Economic buildout of new generating capacity which meets current market reliability regulations and state environmental policies,
  - Regional decarbonization varying on state-by-state basis, but with a rollback of EPA regulations set up during the Biden Administration.
- Natural gas economic pipeline capacity expansion reflects non-announced builds which are profitable and viable:
  - The economic expansion are built upon existing pipeline routes, which are easier to approve than building entirely new pipelines,
  - All forms of pipeline capacity can expand; from those connecting production regions to those of existing gas customers.
  - CRA assumes pipeline capacity can expand up to 75% in size over the study period, assuming they expect to double their revenue.

API Scenario

- CRA worked with API to develop a scenario in which:
  - Power sector demand and non-electric gas demand are the same as in CRA's Reference case,
  - Environmental policy is the same as in CRA's Reference case,
  - LNG export assumptions are the same as in CRA's Reference case.
- API's scenario reflects a world where there is regional hostility to expanding natural gas pipeline capacity in the Southeast:
  - VA, NC, SC, GA, TN, and KY all prevent new natural gas pipeline capacity expansions being built in their states,
  - Any major pipeline capacity expansion in the CRA Reference case cannot be built in these states in the API Scenario,
  - Limits in VA, NC, SC, and GA have a local impact, pushing up the cost of natural gas for consumers and natural gas power plants.
  - Limits in TN and KY affect national gas prices due to their geographic importance to NG infrastructure.
- Higher natural gas costs for power plants push up the generation costs for utilities and drive some switching away from natural gas fuel, resulting in higher electric bills.
  - This increases their reliance on other fuels and imported electricity.

CRA's analysis incorporated fundamental and interconnected perspectives on the natural gas and electric power markets

CRA's Iterative Process



Key Notes

- The **Gas Pipeline Competition Model (GPCM)** is a network flow model of the North American natural gas market, which incorporates detailed representations of supply, demand, and pipeline infrastructure.
  - GPCM is used to assess the impact of the Reference case and scenario on Southeast gas prices.
- CRA's **Natural Gas Fundamentals (NGF)** model provides a bottom-up forecast of North American gas production with a focus on producing a price outlook for Henry Hub.
  - Production cost inputs are aligned with GPCM to produce a consistent outlook.
- **Aurora** is a chronological, hourly dispatch model that represents all major electric pricing zones across North America. It is run in hourly, chronological format and produces energy prices for each zone, along with plant-level dispatch.
  - Aurora power sector gas demand is iterated with gas prices provided by GPCM and NGF until all are in alignment.

Customer rate and bill impacts were approximated using fundamental model inputs

Overview of CRA approach to forecasting customer rate impact

Δ% Retail Bills ~ **Δ% Total Cost of Service** = ∑ **Generation** + **Transmission** + **Distribution**

By scenario

Transmission, **Distribution**: Less impacted by key study variables, potential for minor variation across scenarios.

Generation:

Fixed Costs

- Existing resource base (existing book value)
- Levelized capital cost of new capacity additions, including return on investment
- Operating unit FOM

Variable Costs

- Total system costs (as opposed to marginal cost setting a wholesale price)
    - Fuel
    - VOM
    - Emissions

Upon determining current costs of T&D, CRA assessed the changes in generation costs (assuming T&D grow at the assumed rate of inflation) and thereby approximate the change in retail bills over the study period. CRA assessed starting points based upon the major utilities in each of the states.

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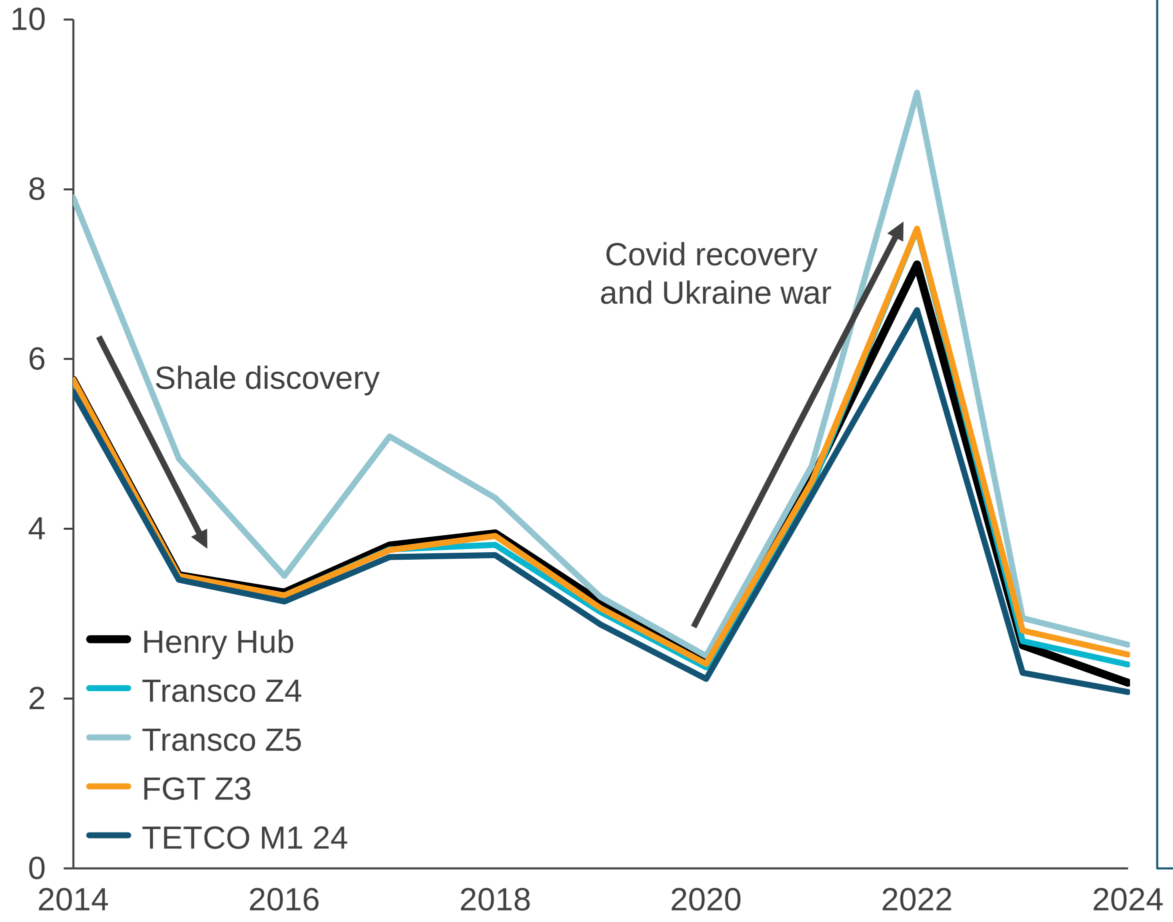
North American natural gas prices fell below $4/MMBtu during the Shale gas era, but have become more volatile in recent years

Historical Natural Gas Prices by Location ($/MMBtu)



Key Notes

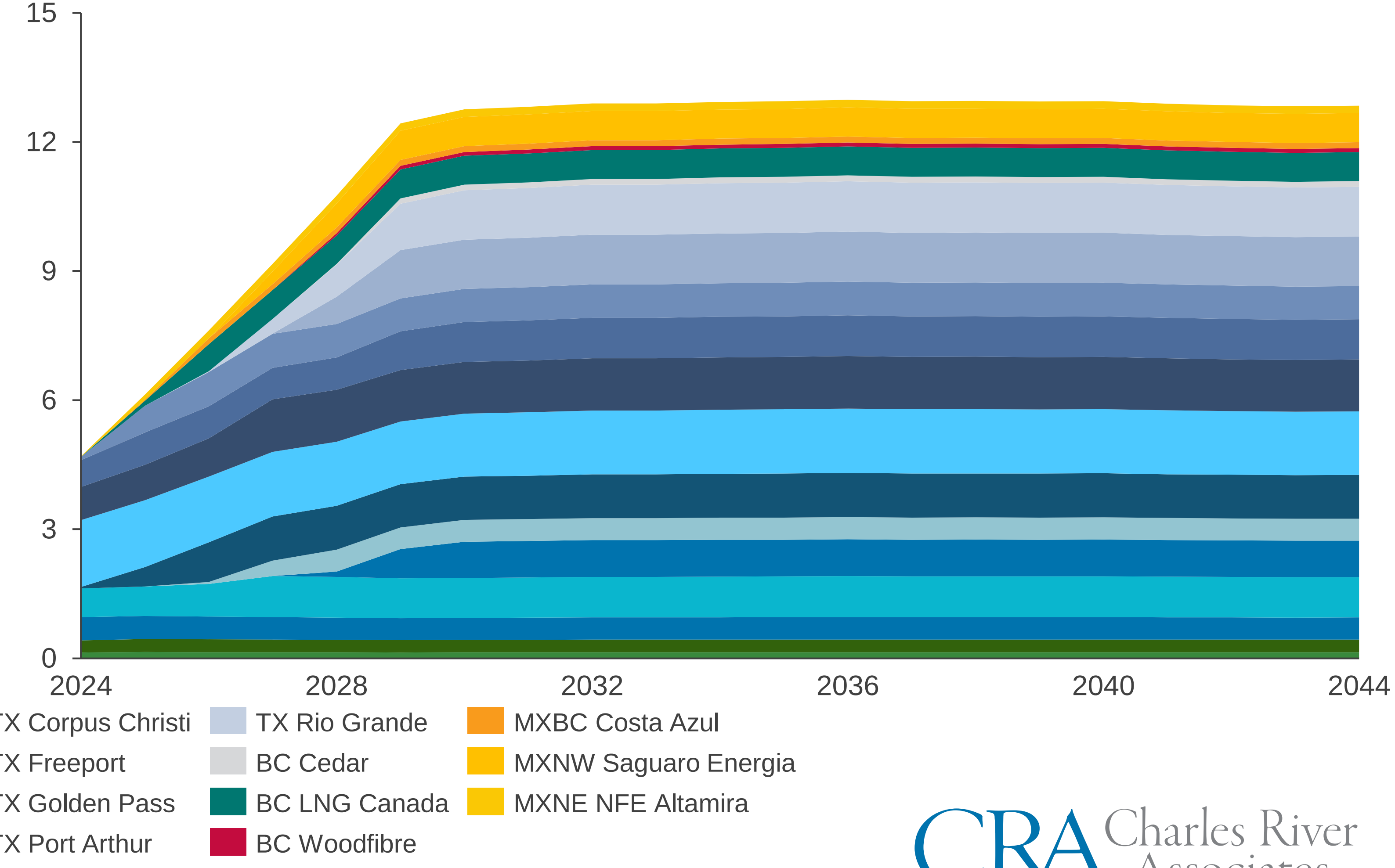
- The main trading hub in the United States for natural gas is Henry Hub (HH), located in Louisiana.
- During the 2010s, the US experienced a substantial drop in natural gas prices due to the Shale revolution,
  - Associated gas production saw natural gas produced as a bi-product of oil production, allowing for negative prices in some areas such as West Texas.
- The Transcontinental line (Transco) and Texas Eastern (TETCO) are the main pipelines that supply the Southeast,
  - The closer basis points trade at a comparable price to Henry Hub,
  - Those closer to New York (Transco Z5) trade at a premium.
- 2021 saw the recovery from the COVID pandemic and 2022 saw Russia's invasion of Ukraine both push up prices:
  - Natural gas demand recovered faster than production could in 2021,
  - In 2022 US LNG exports helped to supply Europe following the loss of Russian gas, but at high costs to the world market.
- Since 2022 natural gas production has oversupplied the market and resulted in record low prices.

LNG capacity will more than double between 2024 and 2030, with facilities expected to see utilization close to 90%

LNG Facilities and Capacity

State	Facility Name	Capacity (TCF)
GA	Elba Island	0.16
MD	Cove Point	0.35
LA	Calcasieu Pass	0.59
LA	Cameron	1.06
LA	CP2	0.96
LA	Delfin	0.58
LA	Plaquemines Pass	1.15
LA	Sabine Pass	1.67
TX	Corpus Christi	1.37
TX	Freeport	1.05
TX	Golden Pass	0.87
TX	Port Arthur	1.30
TX	Rio Grande	1.32
BC (CAN)	Cedar	0.14
BC (CAN)	LNG Canada	0.67
BC (CAN)	Woodfibre	0.10
BC (MEX)	Costa Azul	0.16
NW (MEX)	Saguaro Energia	0.68
NE (MEX)	NFE Altamira	0.20
Total		**14.37**

LNG Exports (TCF)



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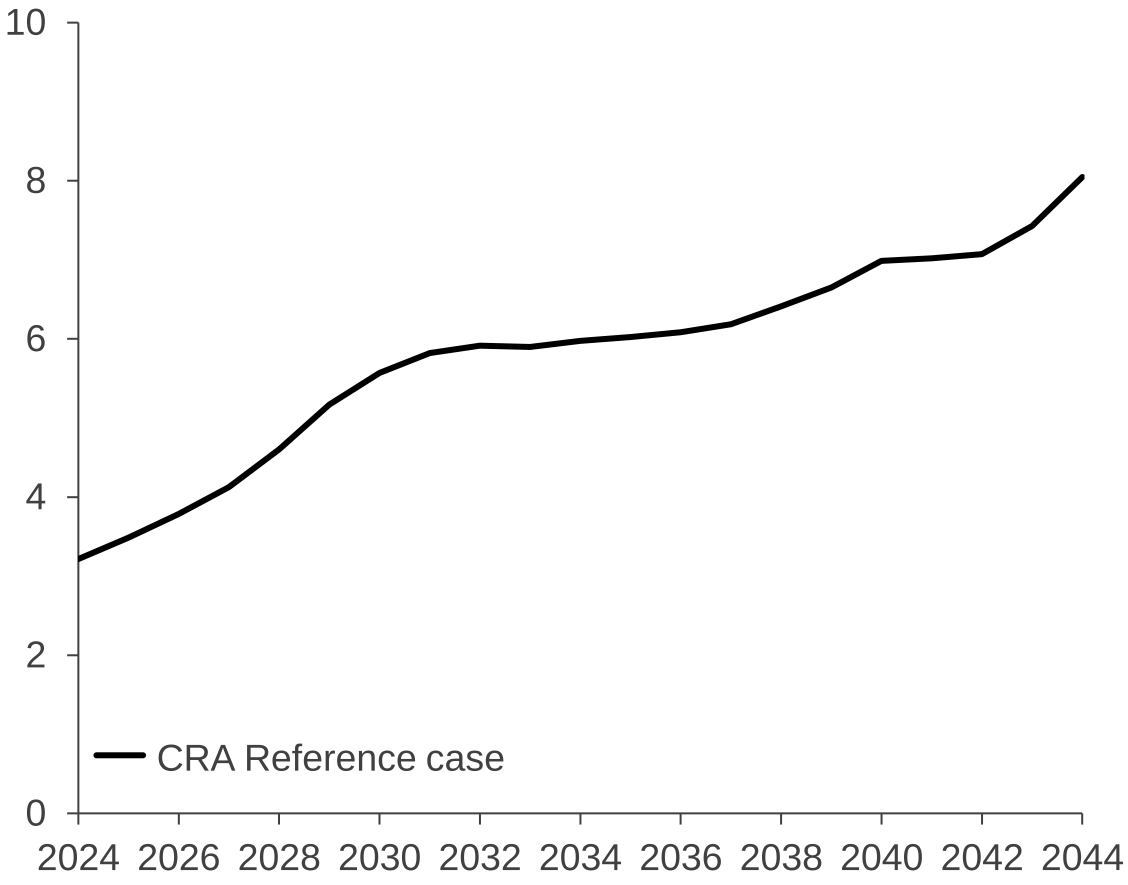
CRA expects Henry Hub prices to grow due to new gas exports, rising production costs, and depletion of proven gas reserves

Henry Hub Outlook ($/MMBtu)

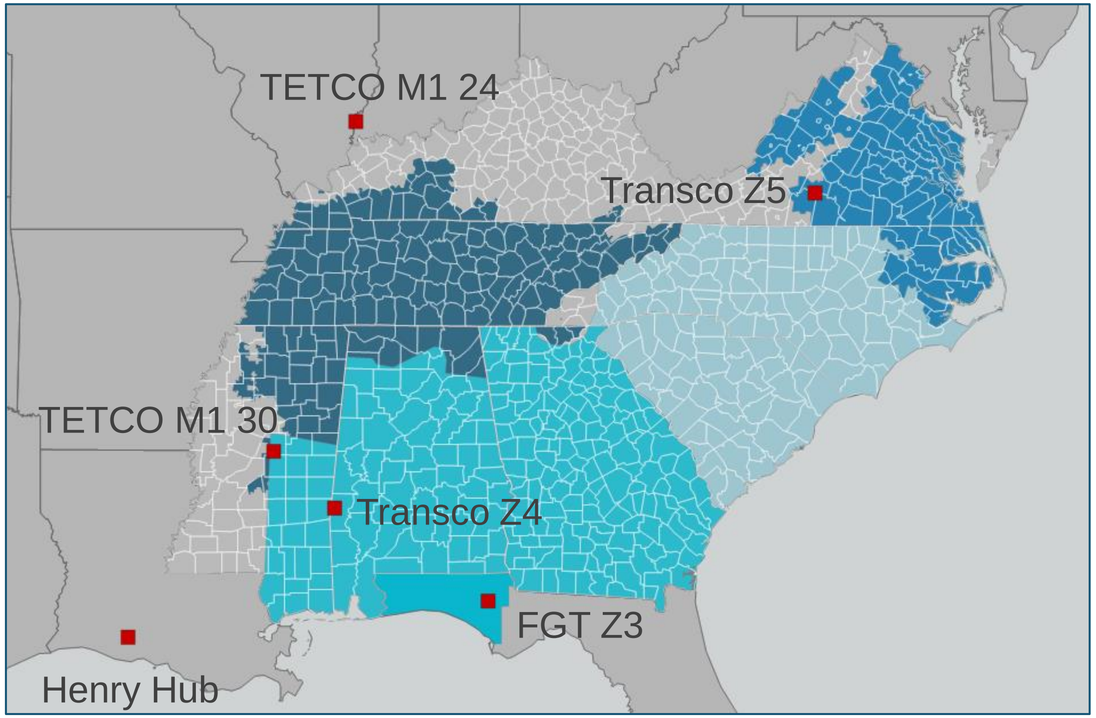


Key Notes

- Henry Hub is currently at a historically low price because natural gas producers have increased production in anticipation of new liquified natural gas (LNG) export facilities coming online.
- North American LNG exports are expected to grow from 5 TCF in 2024 to 13 TCF by 2030.
- In addition, demand from the power sector, as a result of robust electricity demand growth expectations driven by new data center demand, is expected to remain relatively strong through the end of the decade. Longer-term power sector demand erosion is expected as a result of broader decarbonization goals and technology advancement.
- US proven reserves of natural gas are likely to be consumed by the mid-2030s, after which costs will rise to find new reserves, pushing up natural gas prices.

The Southeast contracts its natural gas from different basis points which lie on the Transco, TETCO, and FGT pipelines

Map of Major basis points



Key Notes

- All basis points trade at a differential to Henry Hub.
  - Henry Hub is closely located to natural gas production in Texas, Oklahoma, and Arkansas.
  - Most new LNG facilities are being built on the Gulf Coast in proximity to Henry Hub (See Slide 14).
- Power plants contract for natural gas at these regional basis points along the pipelines, plus delivery fees.
  - Transcontinental Zone 4 (Transco Z4) supplies power plants between Mississippi and Georgia,
  - Transcontinental Zone 5 (Transco Z5) supplies the Carolinas and Virginia,
  - Florida Gas Transmission Zone 3 (TGP Z3) supplies Florida, and
  - Kentucky and Tennessee are supplied by multiple price points along the Texas Eastern Transmission (TETCO) pipelines and Tennessee Gas Pipeline (TGP).
- TETCO and TGP can call upon cheap natural gas from both production in Appalachia and the Gulf coast due to its geographic location.

* Source: S&P Global

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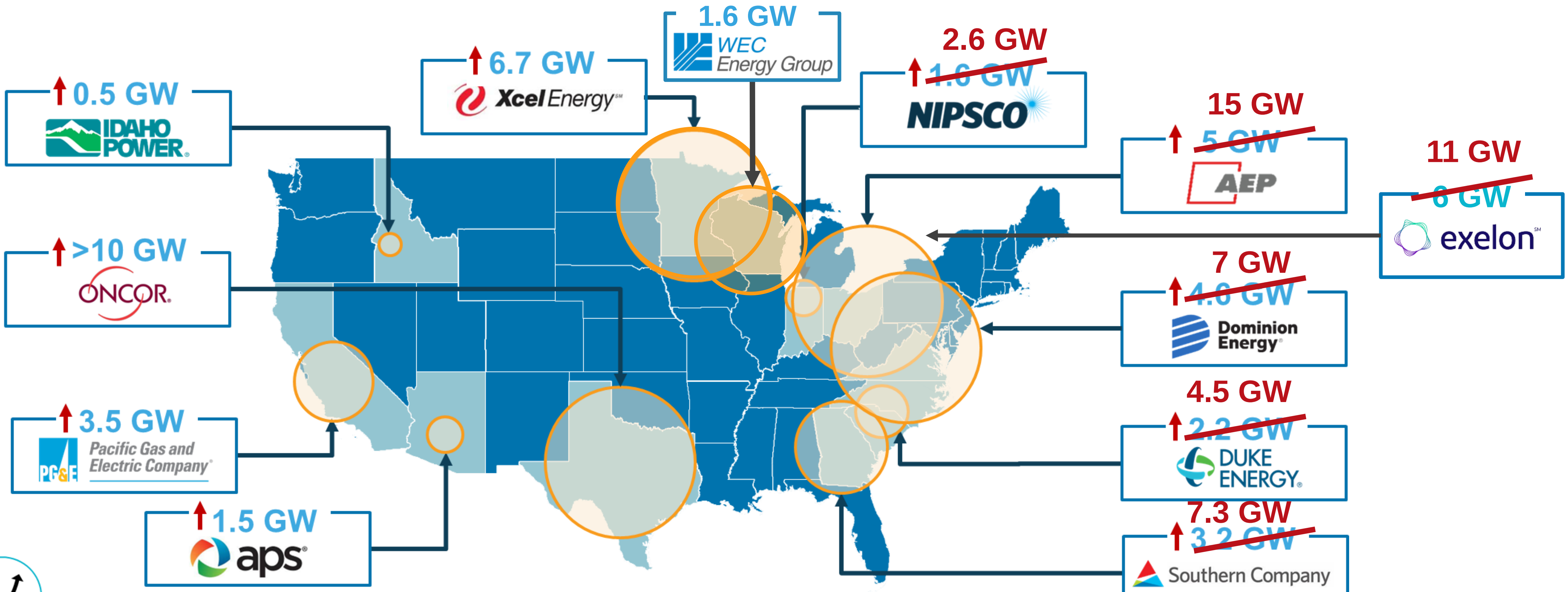
Utilities across the U.S. are revising their 5-year load forecasts upwards in preparation for data center growth to materialize

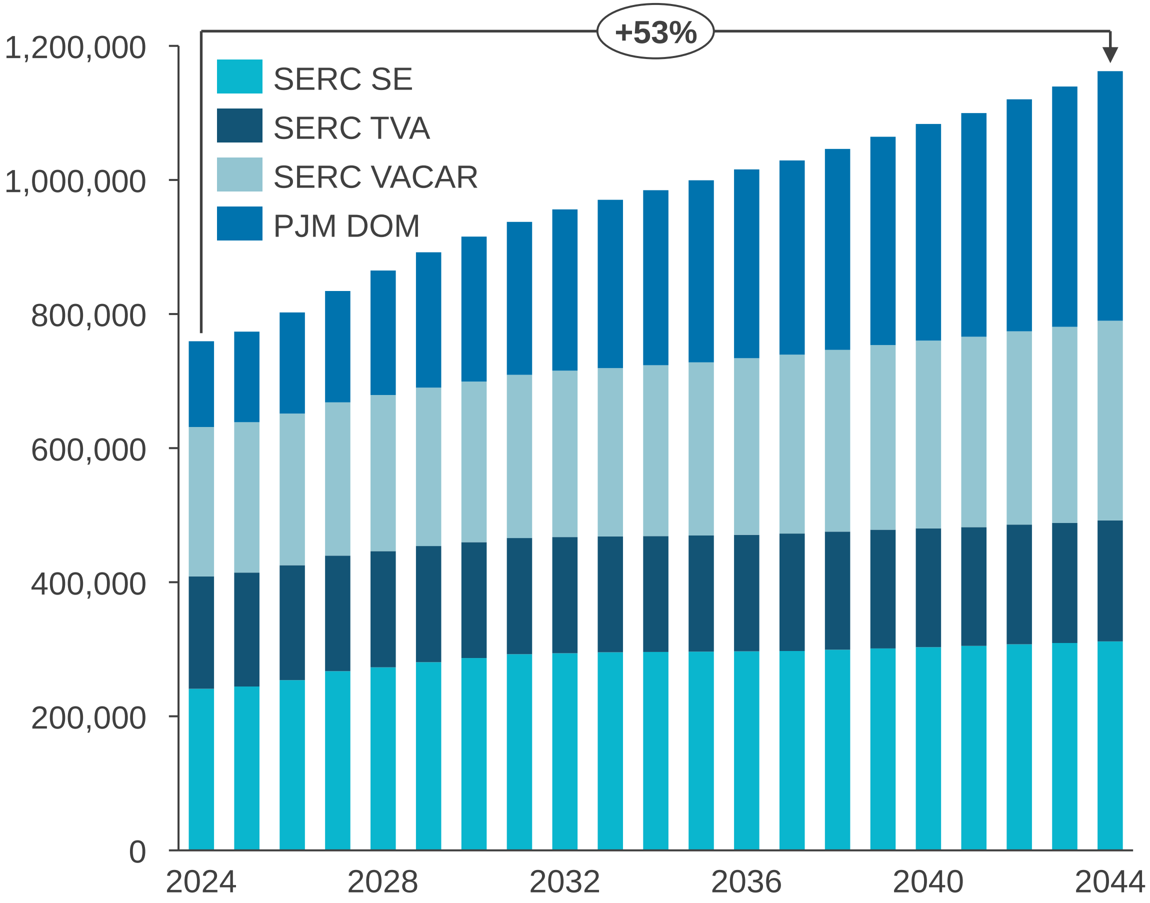


Data center load growth is present across the United States, expanding beyond Northern Virginia and traditional hotspots to **emerging markets nationwide**

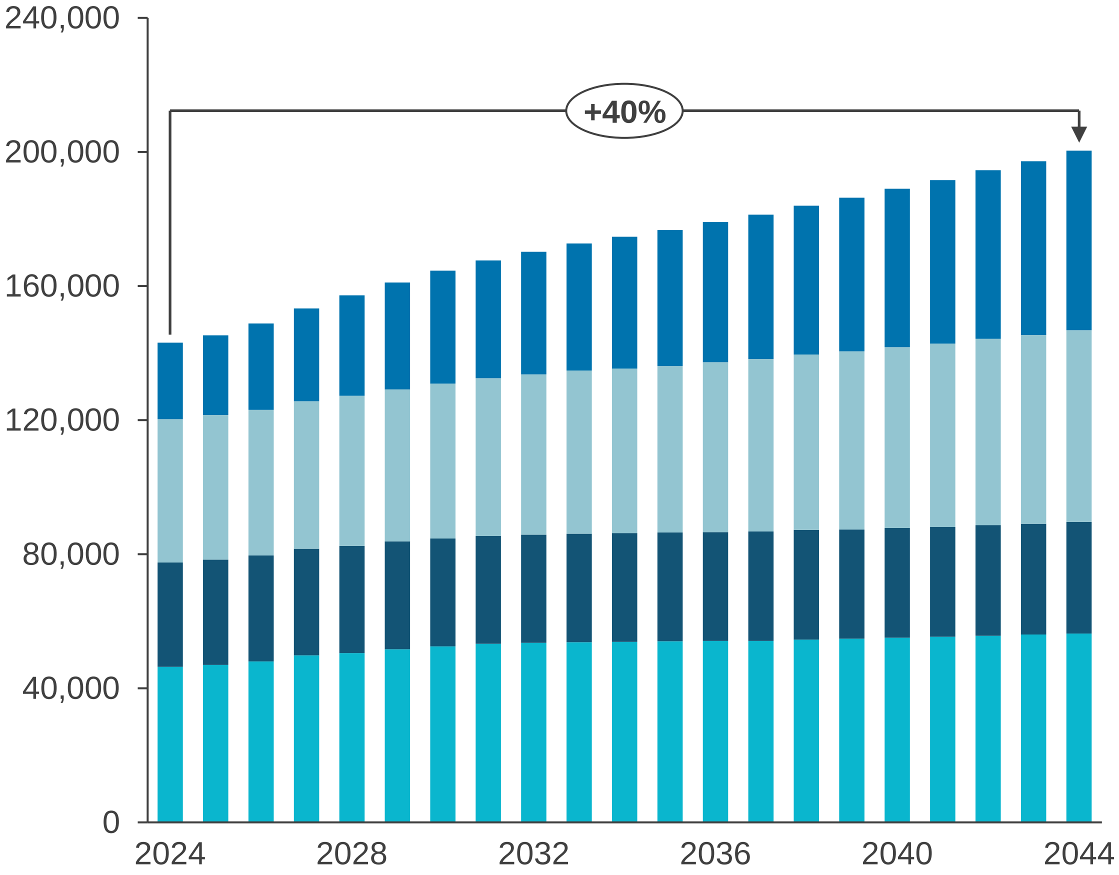
 Source: Utility IRPs, Press Releases

Energy demand in SERC is projected to grow substantially as a result of data center and other large load additions

Energy Demand (GWh)



Non-Coincident Peak Demand (MW)*



* Non-Coincident Peak Demand refers to if all peak demand occurred at the same hour. Often peak demand occurs at different hours in different regions.

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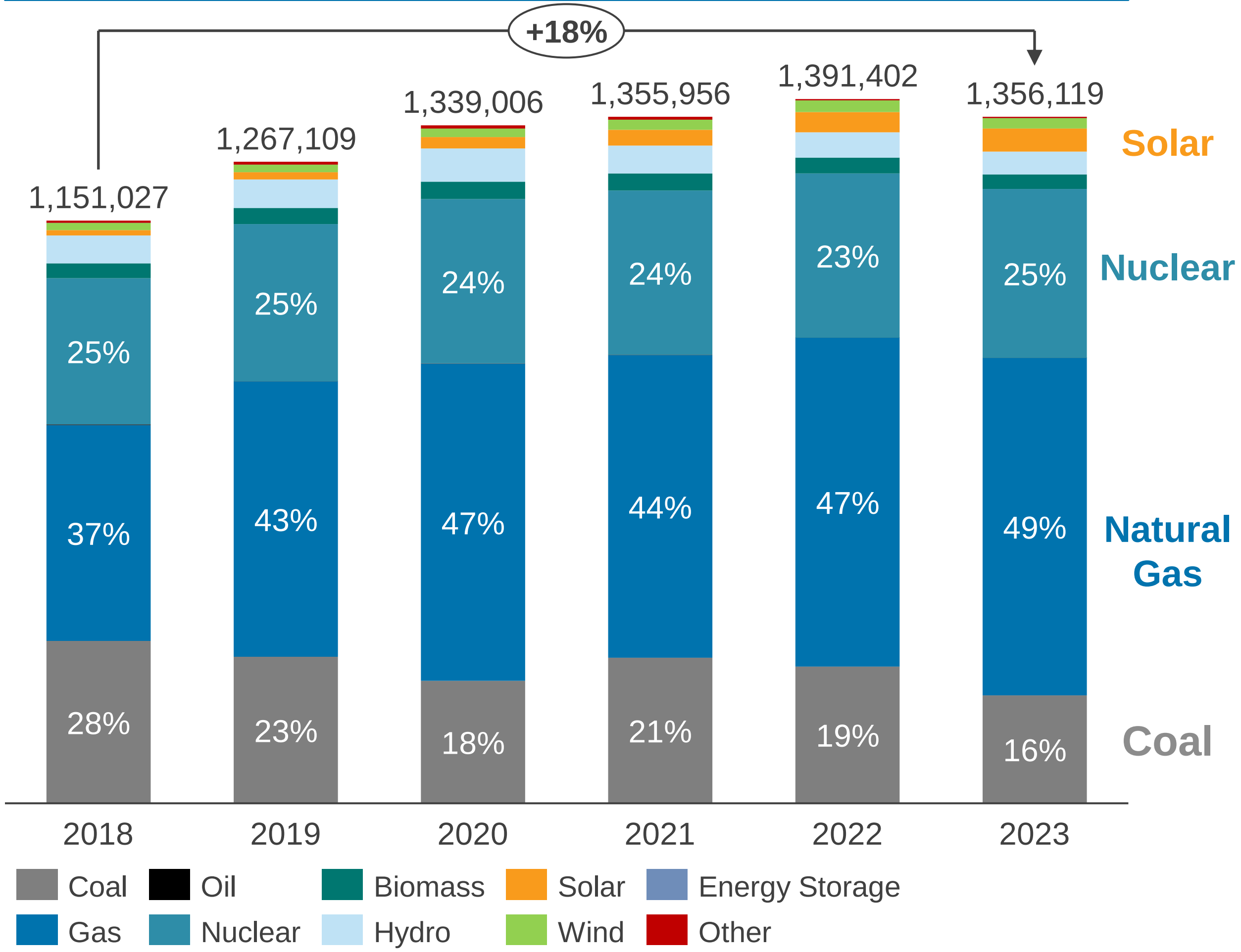
The Southeast is heavily reliant on natural gas resources to supply electric demand

Annual SERC Generation (2018-2023)



Key Notes

- SERC generation has increased by 18% in the past six years. However, it has remained fairly consistent following the COVID pandemic in 2020.
- In 2023, 65% of generation came from coal and natural gas generation.
- Only 10% of generation comes from intermittent renewable resources.
- Wind capacity has seen limited deployment in SERC, with solar heavily favored in recent years and likely to continue into the future.
  - Solar PV and wind generation have increased by 341% and 40%, respectively in the past six years.
  - Virginia and North Carolina have targets for offshore wind capacity, though Virginia's is more binding than North Carolina's.

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Environmental policy assumptions consider federal and state-level regulations

Federal Regulations

- CRA assumes the Inflation Reduction Act (IRA) will continue into the 2030s as part of both cases.
  - Tax credits for renewables, other clean energy, and carbon capture technologies.
  - Permitting for new gas development is encouraged under law, but not in reality.
- CRA assumes EPA GHG regulations on new CCGTs will be withdrawn.
  - These regulations put in place by the Biden Administration are expected to be undone.
- No Federal Carbon price.

State Regulations and Assumptions

Virginia

- Will rejoin the Regional Greenhouse Gas Initiative (RGGI) for the duration of the study period.
- Will achieve its goal of building 5.2 gigawatts of offshore wind by 2034.
- Will not be on course to achieve 100% Renewable Portfolio Standard (RPS) by 2045 as established by the Virginia Clean Economy Act (VCEA) due to high demand growth.*

North Carolina

- Is not on course to achieve 100% electricity sales from carbon-neutral generation by 2050 with a 70% reduction in carbon dioxide emissions from electric generating facilities by 2030 due to demand growth.
- The Governor issued Executive Order No. 218 for 2.8GW of offshore wind by 2030 and 8GW by 2040. CRA believes the goals will not be met, as they have not been legislatively enacted, but that NC will achieve 7.2GW by the end of the study period.

Georgia, Kentucky, South Carolina, and Tennessee

- These states do not have RPS or decarbonization targets.
- CRA does not assume that they will adopt any for the duration of the study period.

* This is in line with a recent study by the Joint Legislative Audit and Review Commission (JLARC) in Dec, 2024 regarding Data Centers in Virginia, which suggested natural gas would still be necessary out to 2040. The JLARC used similar demand assumptions to CRA and had a similar buildout to CRA's Reference Case.

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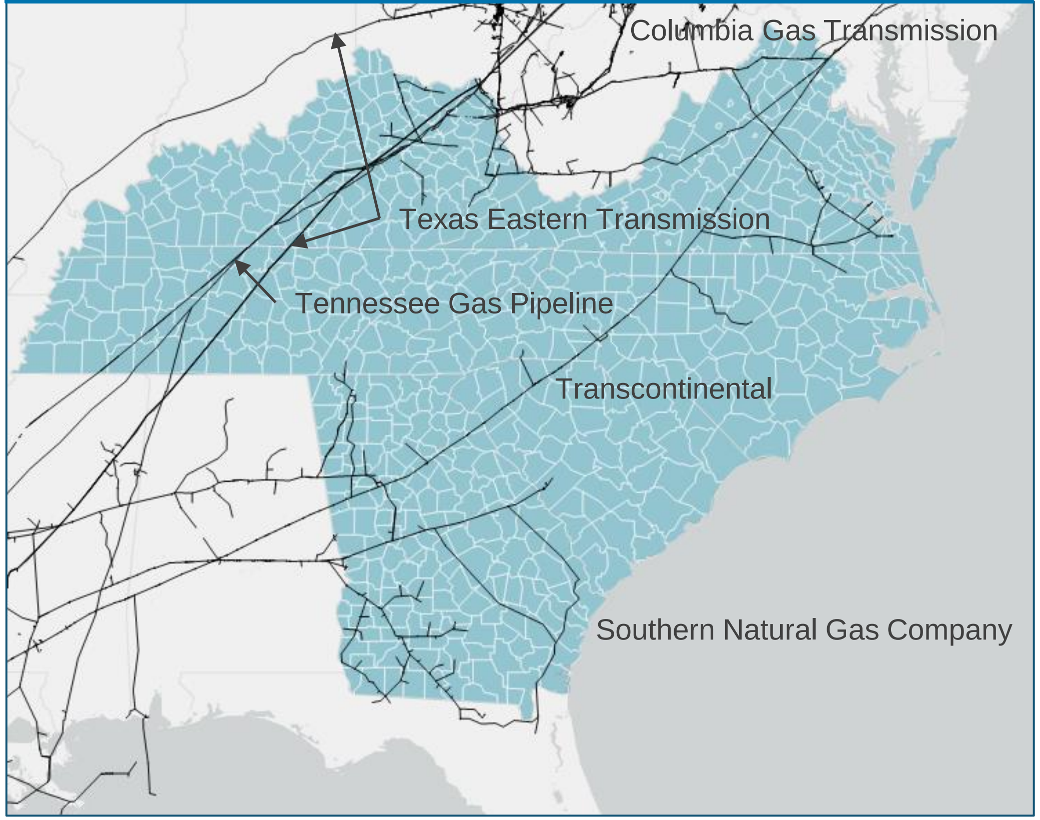
Natural gas pipeline capacity expands for a variety of reasons; be it growing the existing network or linking to new customers

Map of Major Pipelines



State with restricted pipeline capacity expansion in API's Scenario

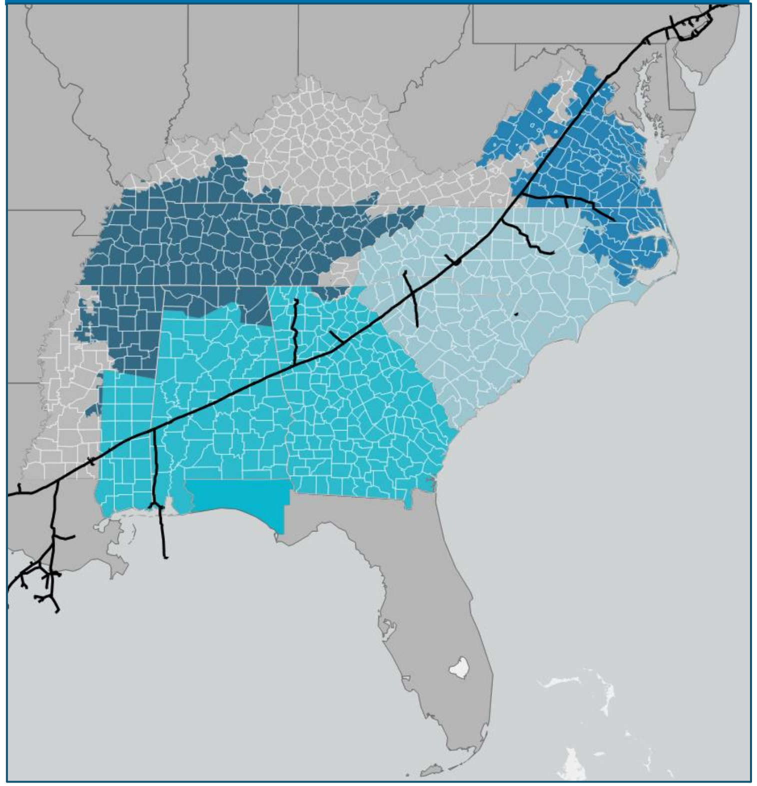
* Source: S&P Global

Key Notes

- There are five major natural gas pipeline networks across the key Southeastern states:
  - Transcontinental (Transco),
  - Columbia Gas Transmission,
  - Texas Eastern Transmission (TETCO),
  - Tennessee Gas Pipeline (TGP), and
  - Southern Natural Gas Company,
- Transcontinental is the most important to the majority of the states in the Southeast.
- The pipelines passing through Tennessee and Kentucky have the most direct impact on US-wide prices.
- The API Scenario prevents most of these expansions from taking place and thus reflects the differences between the CRA Reference case and API Scenario.

Transcontinental saw large expansions in Georgia and the Carolinas in order to meet power sector demand in the region

Transcontinental (Transco)*



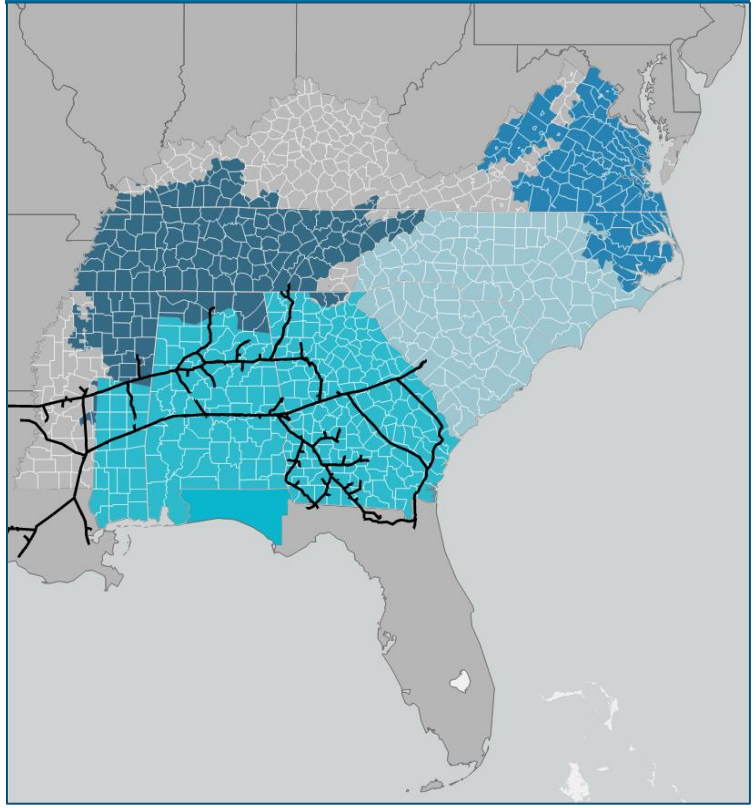
Transcontinental Pipeline Capacity Expansion

Expansion Type	Pipeline section	Customer	State	Initial Capacity (MMCF/d)	Final Capacity (MMCF/d)	Growth
Gas consumer	Transco Z4 St 85 - Z5	Atlanta Gas Light Co.	Georgia	500	875	75.00%
Gas consumer	Transco Z4 St 85 - Z5	Georgia Power Co	Georgia	363	635	75.00%
Gas consumer	Transco Z5 S VA Lat	Piedmont Natural Gas Co., Inc.	North Carolina	160	280	75.00%
Gas consumer	Transco Z4 St 85 - Z5	Georgia: Misc Ind Gas Mkt	Georgia	200	204	2.00%
Gas consumer	Transco Z4 Momentum exp	Georgia Power Co	Georgia	136	191	40.37%
Gas consumer	Transco Z5 South Del	South Carolina Electric & Gas Co.	South Carolina	100	175	75.00%
Gas consumer	Transco Z4 St 85 - Z5	Georgia: Misc LDC Gas Sales	Georgia	59	103	75.00%
Gas consumer	Transco Z4 Southcoast Exp	Atlanta Gas Light Co.	Georgia	61	75	23.30%
Gas consumer	Transco Z4 Southcoast Exp	Georgia Power Co	Georgia	50	64	28.43%
Interregional expansion	Transco Z5	Transco Z5 North	Virginia	2,521	4,411	75.00%
Interregional expansion	Transco Z5 North	Transco Z5 North Rcpt	Virginia	3,600	4,411	22.55%
Interregional expansion	Transco Z5 South	Transco Z5	Virginia	3,009	3,835	27.44%

* Source: S&P Global

Southern Natural Gas Company saw limited expansion in Georgia, South Carolina, Tennessee and Louisiana

Southern Natural Gas Company*



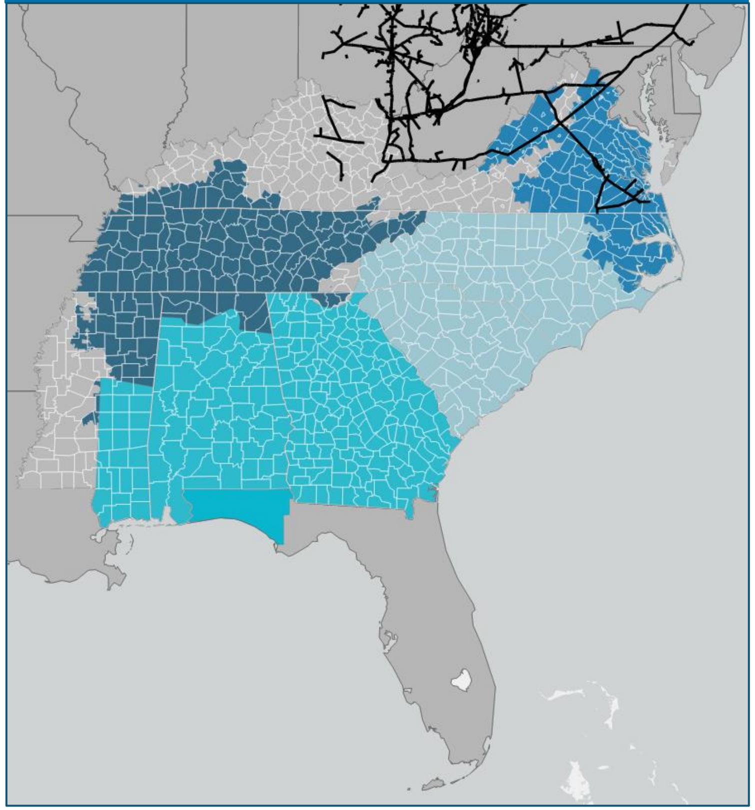
Southern Natural Pipeline Capacity Expansion

Expansion Type	Pipeline section	Customer	State	Initial Capacity (MMCF/d)	Final Capacity (MMCF/d)	Growth
Gas consumer	SoNat Z1 (S TN)	Tennessee Valley Authority	Tennessee	830	885	6.65%
Gas consumer	SoNat Z3 (S GA) Macon to SC	South Carolina Electric & Gas Co.	South Carolina	350	378	6.65%
Gas consumer	SoNat Z0 (SW LA)	Entergy Louisiana Inc	Louisiana	50	88	75.00%
Gas consumer	So Nat Z2 (S AL)	JEA	Florida	10	18	75.00%
Gas consumer	So Nat Z2 (S AL)	Seminole Electric Coop Inc	Florida	10	15	50.00%
Interregional expansion	SoNat Z3 (S GA) Macon to SC	Southern Natural Z3 (S GA)	Georgia	632	975	54.30%

* Source: S&P Global

Columbia Gas Transmission supplies Virginia and the Mid-Atlantic with natural gas from the Marcellus and Utica

Columbia Gas Transmission*



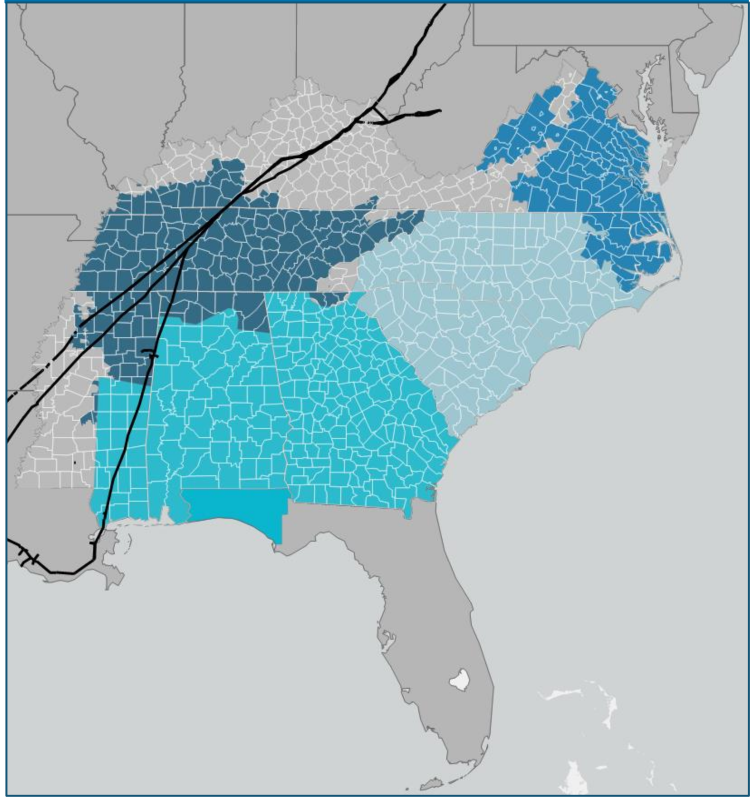
Columbia Gas Transmission Capacity Expansion

Expansion Type	Pipeline section	Customer	State	Initial Capacity (MMCF/d)	Final Capacity (MMCF/d)	Growth
Gas consumer	Col Gas (1) Southeast VA	Col Gas (10) VA and MD	Virginia	500	875	75.00%
Gas consumer	Col Gas (10) VA and MD	Col Gas (4) E PA	Virginia	300	525	75.00%
Gas consumer	Col Gas (10) VA and MD	Virginia: Misc Ind Gas Mkt	Virginia	100	110	1.88%
Gas consumer	Col Gas (10) VA and MD	Columbia Gas of Virginia, Inc.	Virginia	35	61	53.05%
Gas consumer	Col Gas (10) VA and MD	Roanoke Gas Co.	Virginia	50	58	11.74%
Natural gas production	Col Gas (3) S WV / E KY Sup	Marcellus Shale	West Virginia	1,300	2,275	75.00%
Natural gas production	Col Gas (8) W PA/N WV Sup	Marcellus Shale	Pennsylvania	1,500	2,249	49.95%
Natural gas production	Col Gas Leach Xpress	Marcellus Shale	West Virginia	705	1,234	75.00%
Natural gas production	Col Gas (7&5) Ohio Sup	Conventional gas production	Ohio	75	131	75.00%
Natural gas production	Col Gas (4) E PA Sup	Marcellus Shale	Pennsylvania	5	8.75	75.00%

* Source: S&P Global

TGP is one of two major pipeline networks that passes through Tennessee and connects HH to the Appalachian shale plays

Tennessee Gas Pipeline (TGP)*



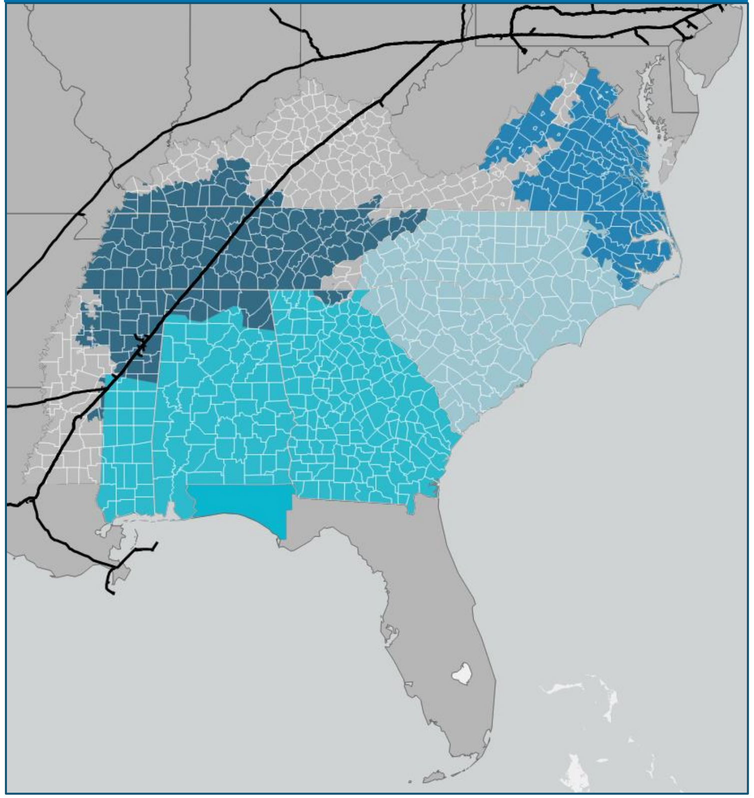
Tennessee Gas Pipeline Capacity Expansion

Pipeline	Pipeline section	Customer	State	Initial Capacity (MMCF/d)	Final Capacity (MMCF/d)	Growth
Gas consumer	Tenn Z2 Del	Tennessee Valley Authority	Tennessee	344	355	3.28%
Gas consumer	Tenn Z1 100 Leg Del	Tennessee: Misc Ind Gas Mkt	Tennessee	88	154	75.00%
Gas consumer	Tenn Z2 Del	Duke Energy Kentucky	Kentucky	59	81	36.74%
Gas consumer	Tenn Z2 Del	Tennessee Valley Authority	Kentucky	25	44	75.00%
Natural gas production	Marcellus Shale	Marcellus Shale	West Virginia	43	75	31.35%
Natural gas production	Utica Shale	Utica Shale	Ohio	50	75	21.75%

* Source: S&P Global

TETCO has two main corridors from the Mid-Atlantic: one passing through TN and the other through the Mid-West

Texas Eastern Transmission (TETCO)*



Texas Eastern Transmission Capacity Expansion

Pipeline	Pipeline section	Customer	State	Initial Capacity (MMCF/d)	Final Capacity (MMCF/d)	Growth
Gas consumer	TX E M1 E S BND	Tennessee: Misc Ind Gas Mkt	Tennessee	88	154	75.00%
Gas consumer	Tx E M1 E N BND	Alabama: Misc Ind Gas Mkt	Alabama	25	44	75.00%
Gas consumer	TX E M1 E S BND	Alabama: Misc Ind Gas Mkt	Alabama	25	44	75.00%
Gas consumer	Tx E ELA	Mississippi: Misc Ind Gas Mkt	Mississippi	20	30	50.00%
Gas consumer	TX E M2 E KY S BND	Kentucky Misc Gas-fired Gen	Kentucky	10	13	27.34%
Natural gas production	TX E M2 Marc Sup Rec Total	Marcellus Shale	Pennsylvania	3,100	3,574	15.28%
Natural gas production	Tx E STX Agua Dulce	Eagle Ford Shale	Texas	752	785	4.40%
Natural gas production	Tx E ELA Venice Off	Conventional gas production	Louisiana	6	11	75.00%

* Source: S&P Global

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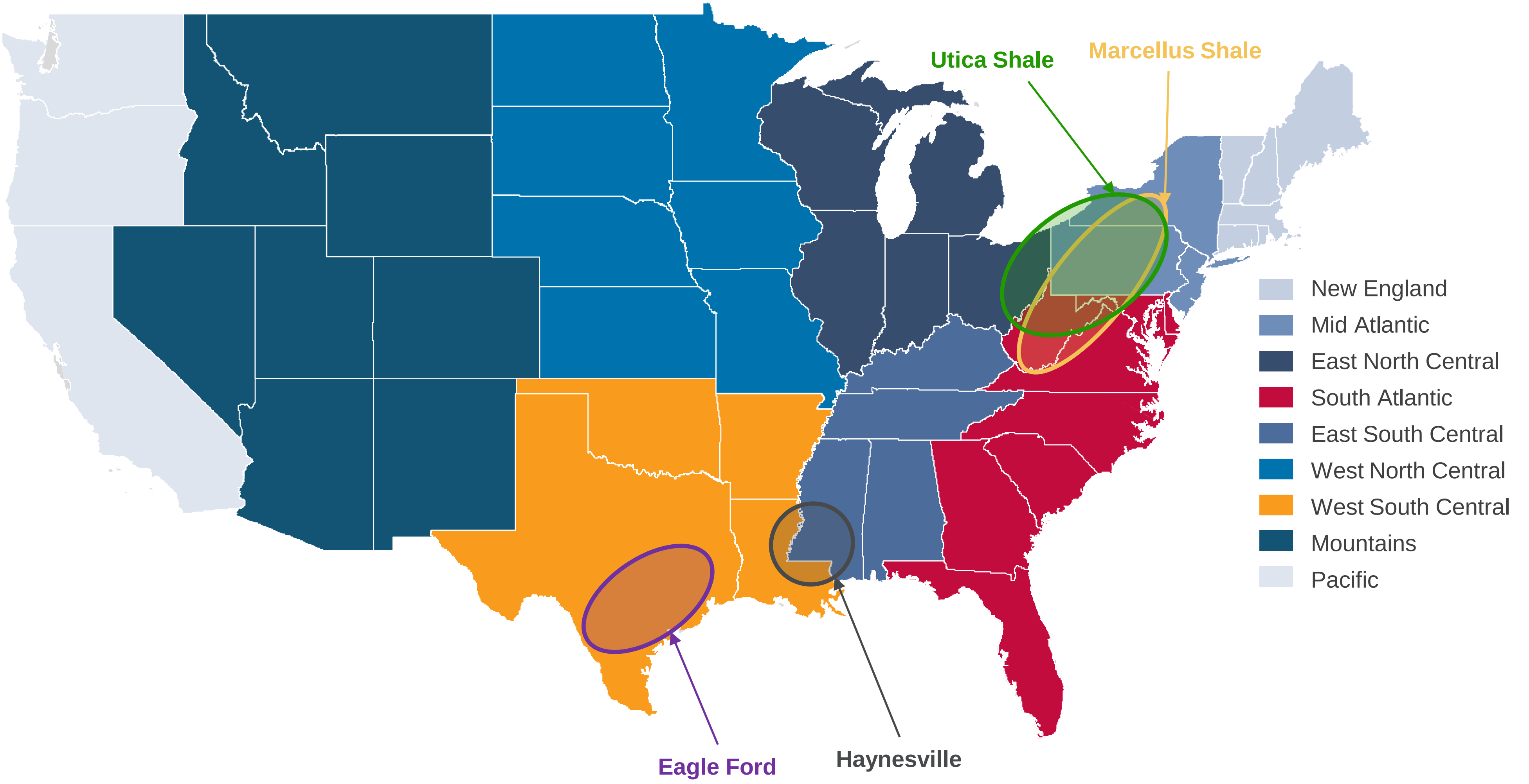
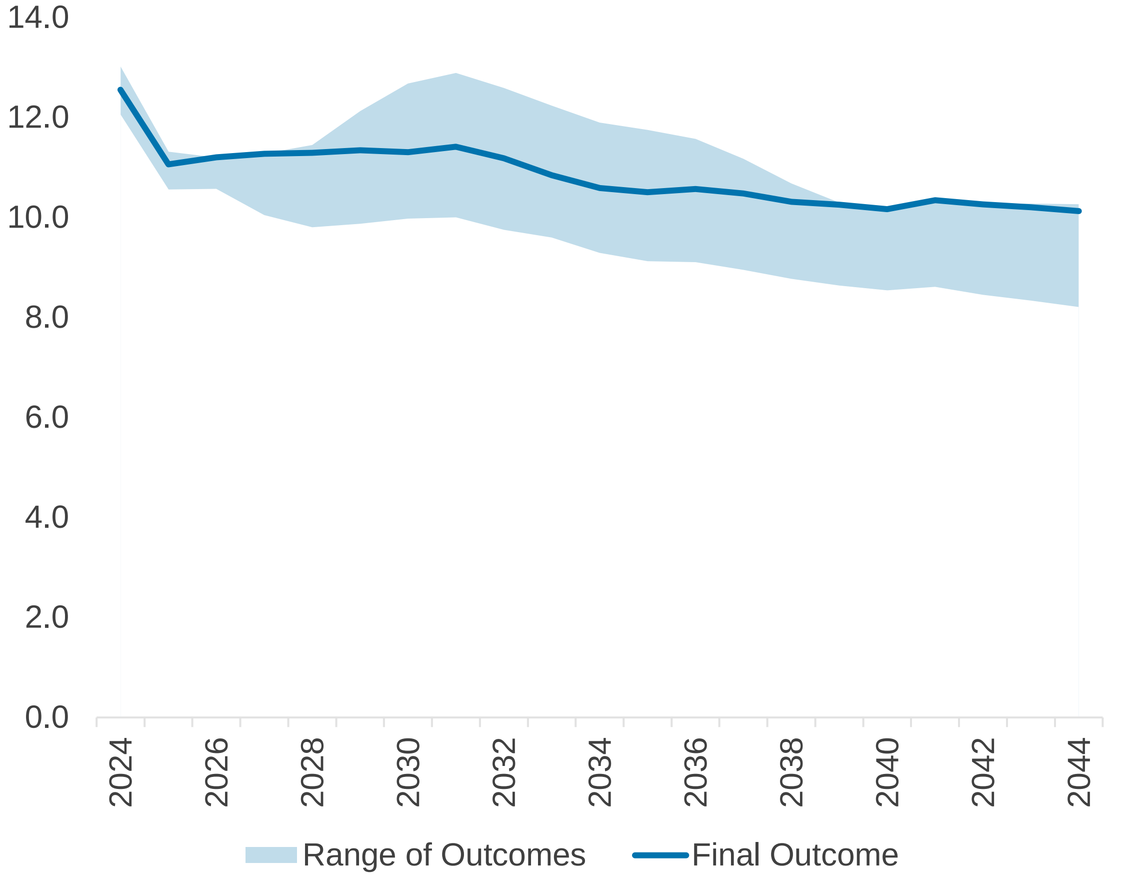
Regional gas demand is aggregated by United States Census Area; the major centers of gas production are in Appalachia and WSC



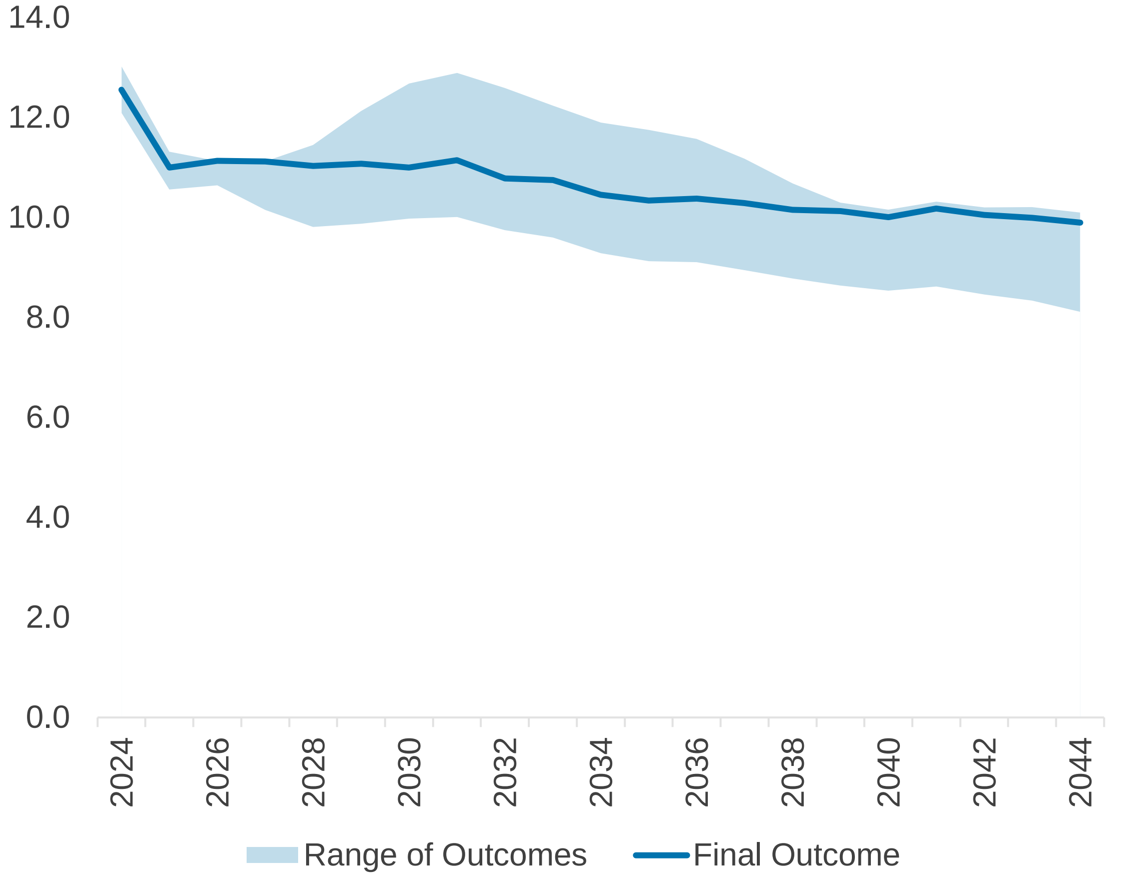
CRA Charles River Associates

CRA's analysis resulted in a range of potential national gas demand projections, with a general expectation for gradual declines

CRA Reference case US Electric Sector Gas Demand Comparison (TCF)



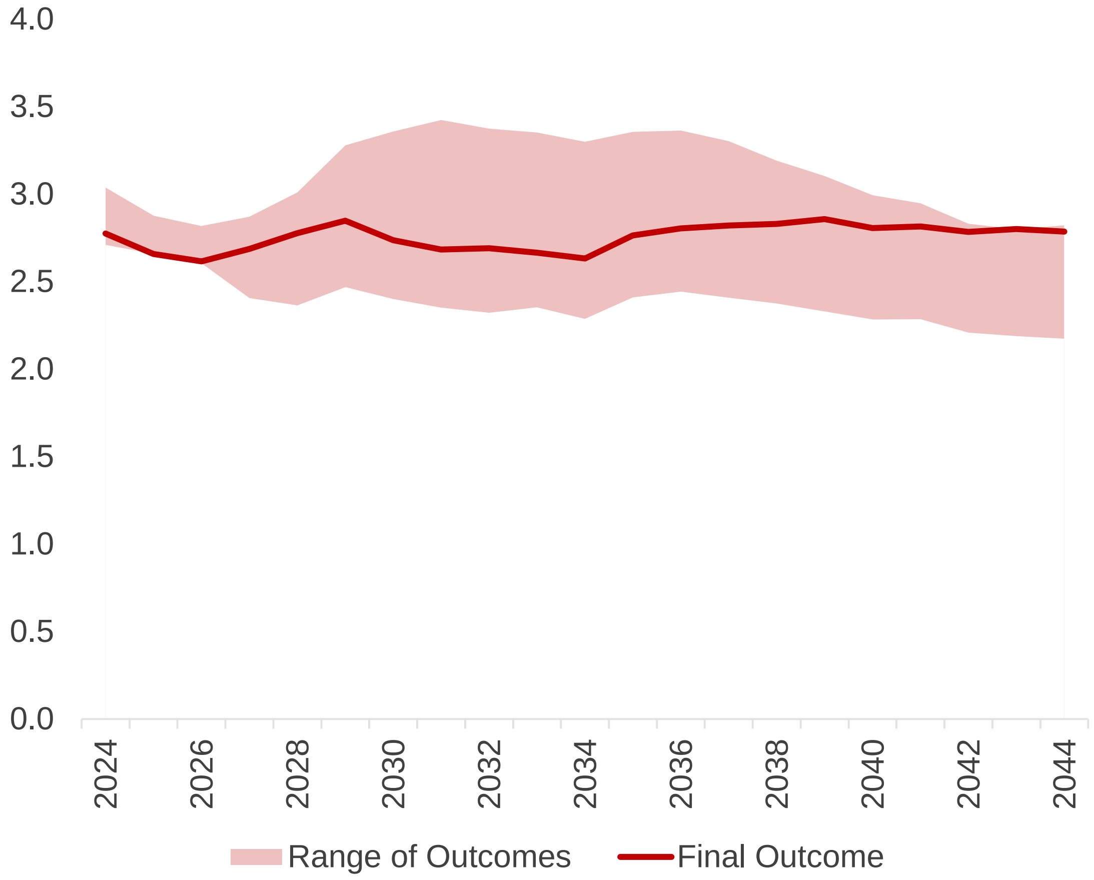
API Scenario US Electric Sector Gas Demand Comparison (TCF)



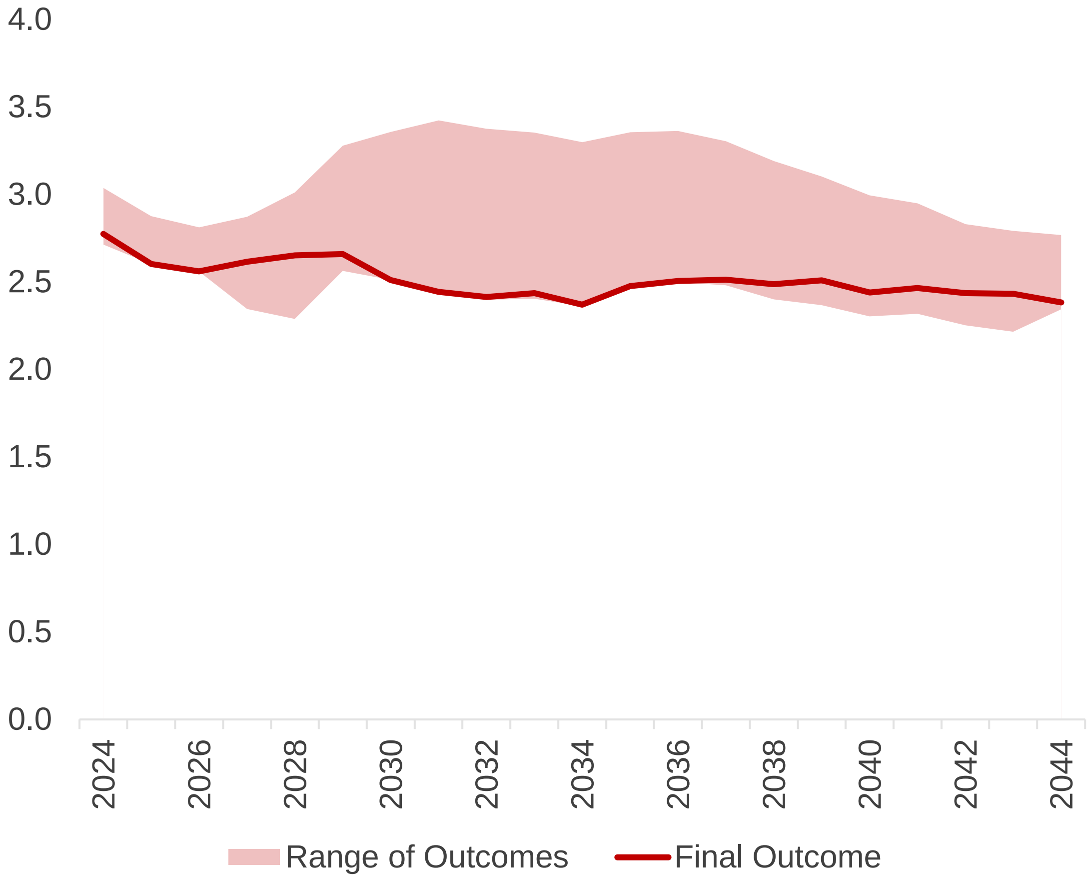
CRA Charles River Associates

Limited pipeline capacity expansion in the South Atlantic region resulted in lower gas demand projections vs. the CRA Reference

CRA Reference case South Atlantic Electric Sector Gas Demand Comparison (TCF)

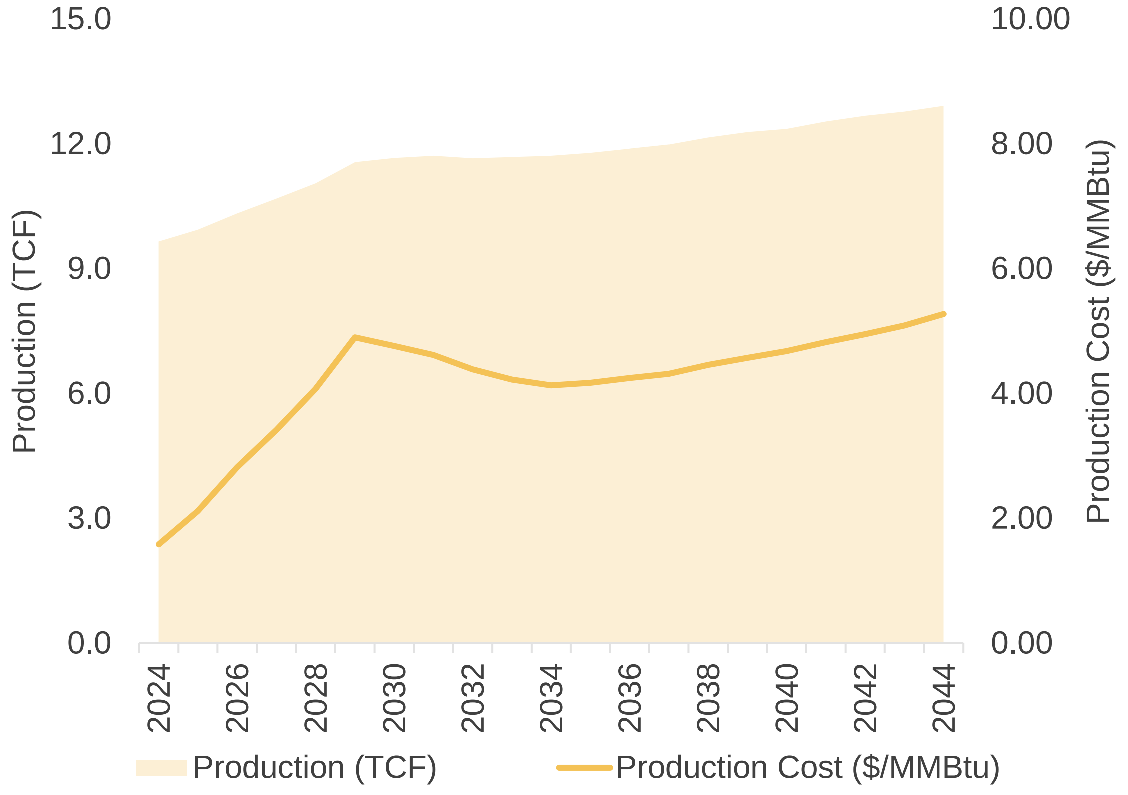


API Scenario South Atlantic Electric Sector Gas Demand Comparison (TCF)

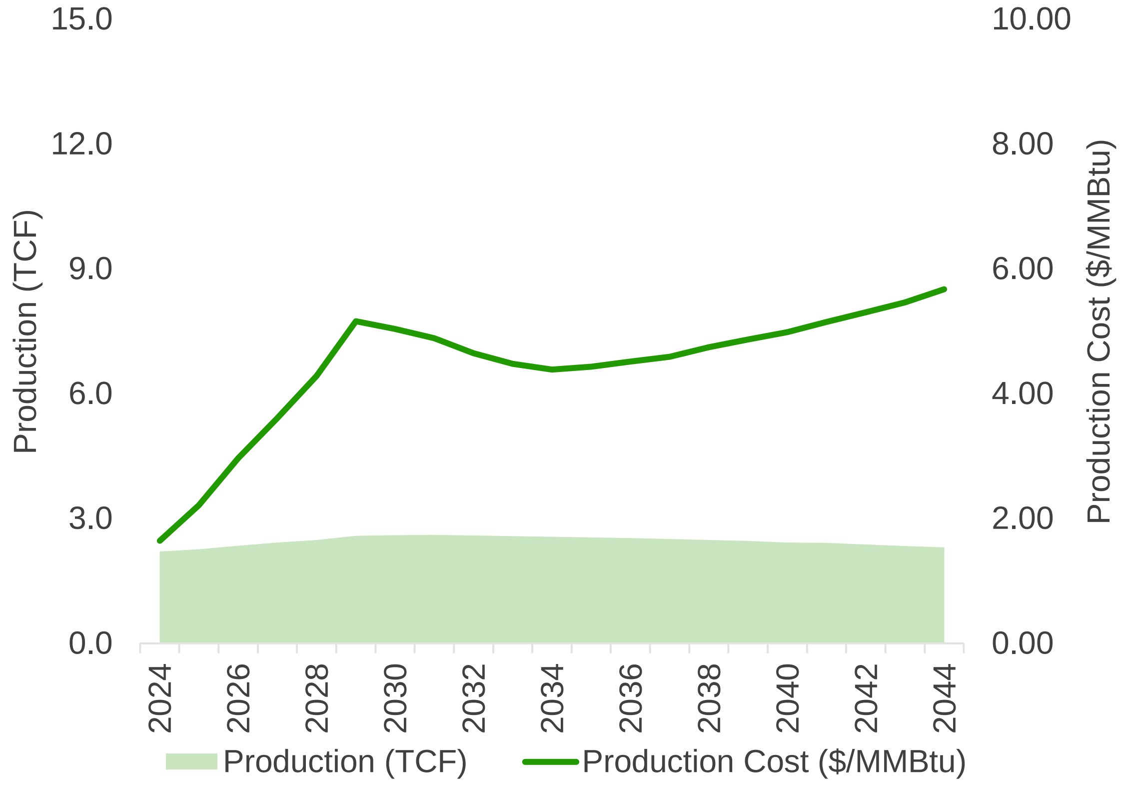


The Marcellus and Utica primarily supply the Midwest and Henry Hub; near term costs rise to meet LNG demand before declining

Marcellus Production vs Production Cost*



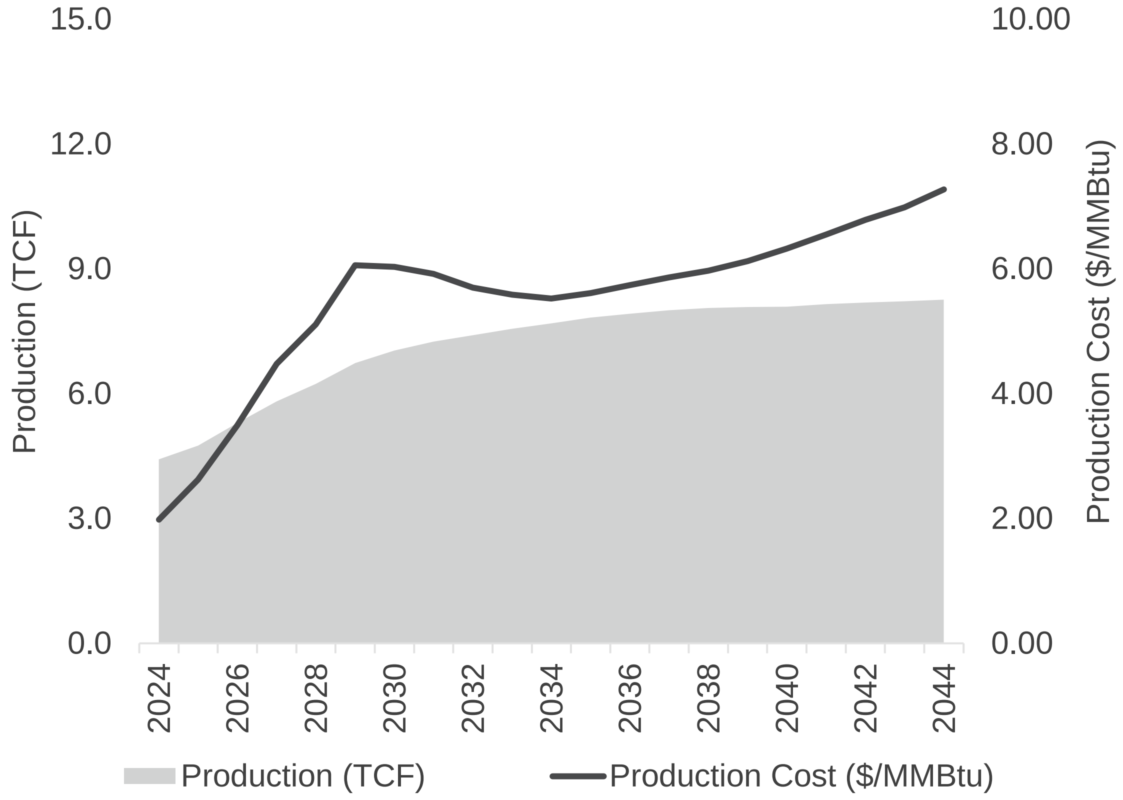
Utica Production vs Production Cost*



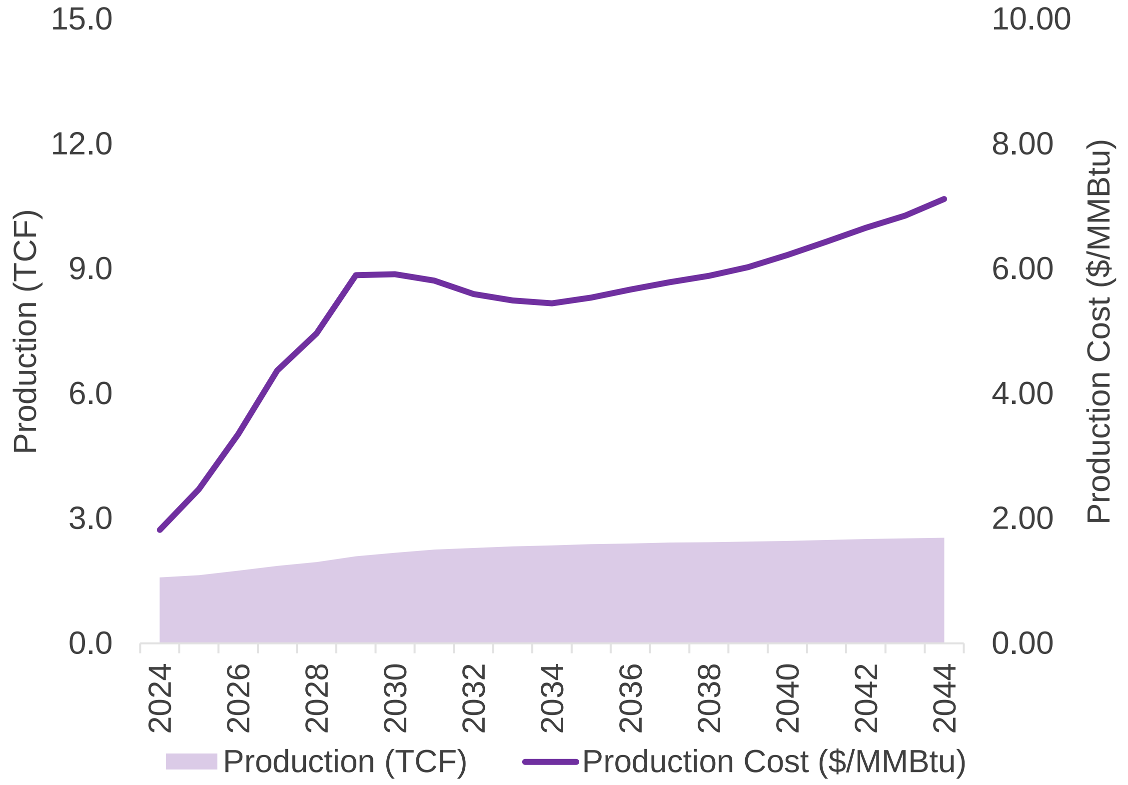
* Production and production costs come from CRA's Reference case. Both cases had the same production cost assumptions, though production varied between cases due to pipeline restrictions.

Transco takes natural gas from Haynesville and Eagle Ford; their costs rise in the long term as proven reserves are expended

Haynesville Production vs Production Cost*



Eagle Ford Production vs Production Cost*



* Production and production costs come from CRA's Reference case. Both cases had the same production cost assumptions, though production varied between cases due to pipeline restrictions.

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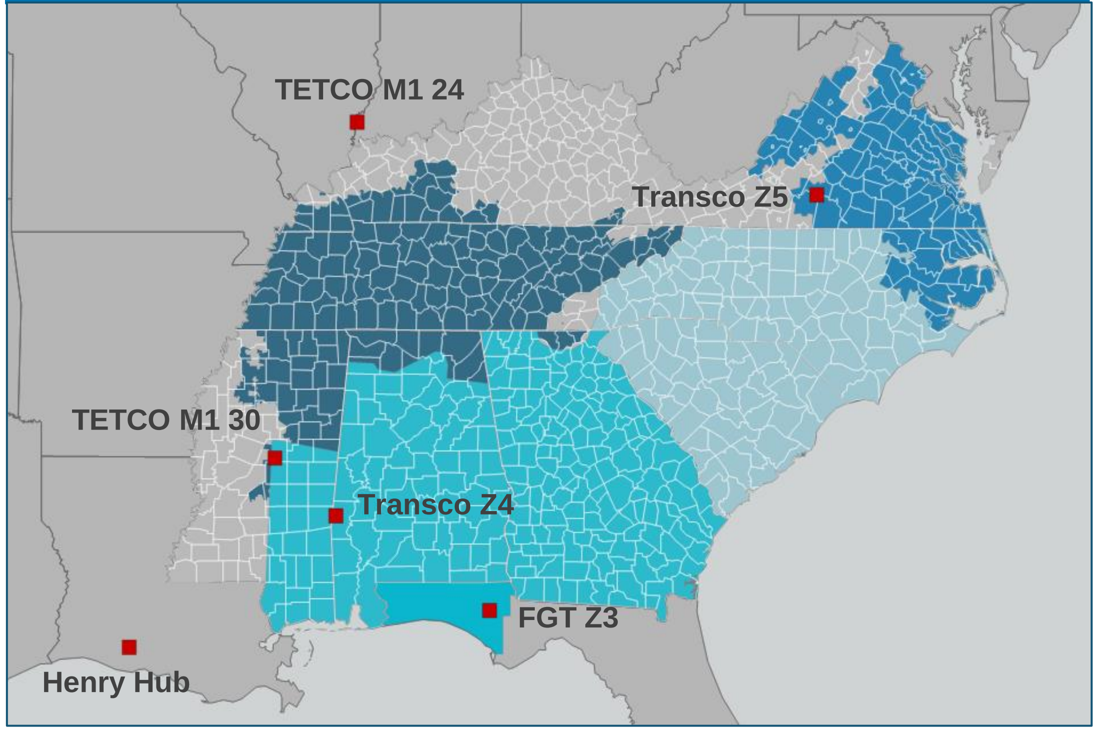
The Southeast draws its gas from different basis points on the Transco, TETCO, and FGT pipelines

Map of major basis points



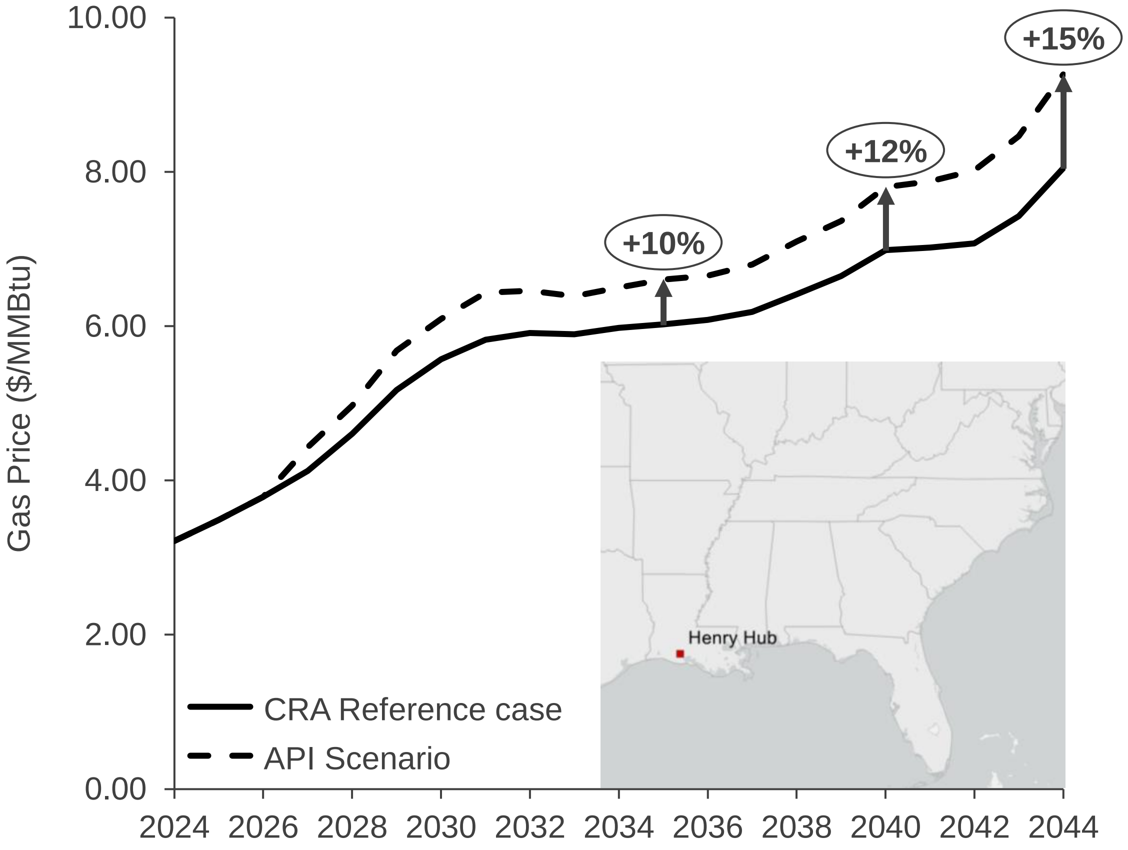
Key Notes

- Historically, natural gas flowed up from Henry Hub to the Northeast via:
  - Transcontinental Pipeline,
  - Texas Eastern Transmission, and
  - Tennessee Gas Pipeline.
- With the development of Shale Gas in Ohio and Pennsylvania (Appalachia), natural gas has begun to flow in reverse and has helped lower prices across the country.
- The recently-built Mountain Valley Pipeline has connected Transco Z5 to the shale plays in PA and has helped to lower prices in the region.
  - The pipeline faced considerable opposition and does not expect to have be expanded further in either case.

* Source: S&P Global

Restricted pipeline capacity expansion is likely to impact natural gas prices by 10-15% over the study period

Henry Hub gas price ($/MMBtu)

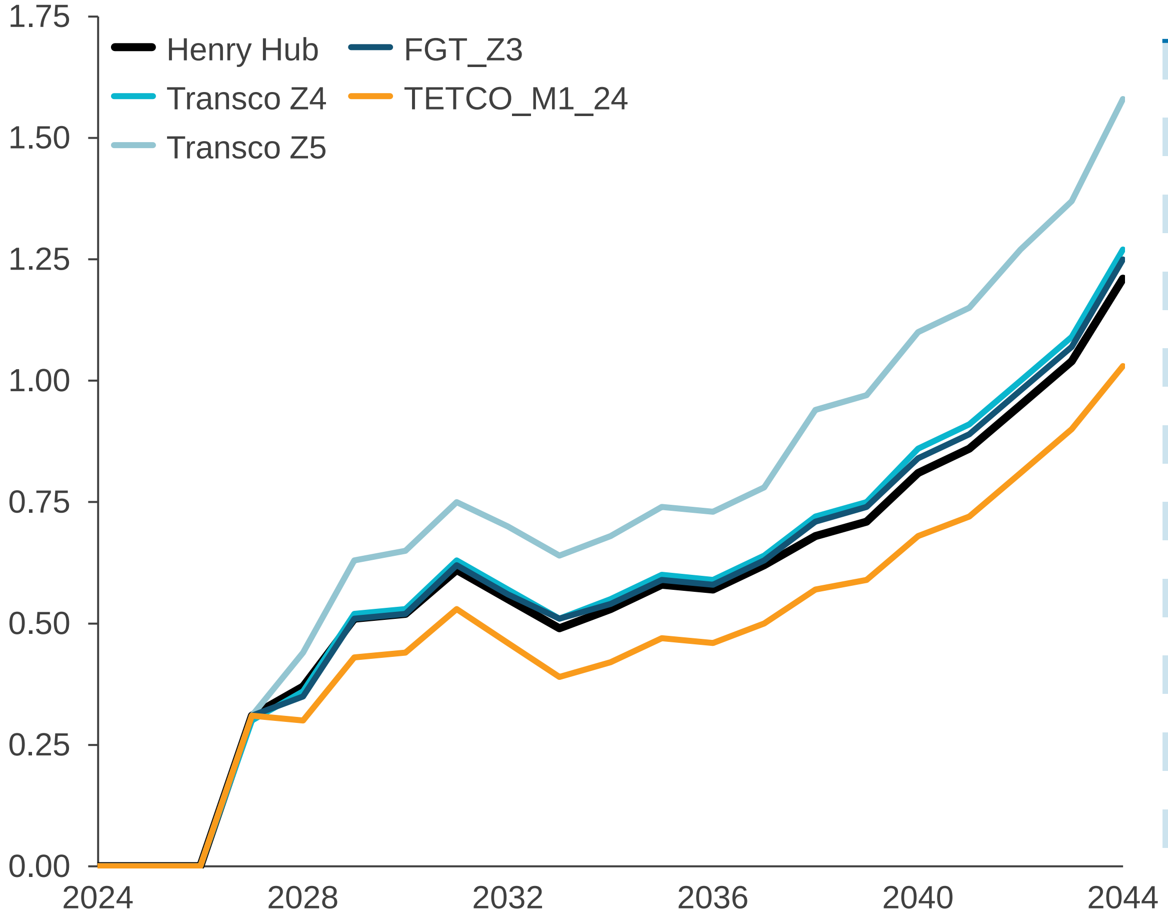


Key Notes

- Natural gas prices are expected to rise in the coming years as new liquified natural gas (LNG) facilities come online to export American natural gas.
  - Most LNG plants are built in Texas and Louisiana near the main trading point for natural gas: **Henry Hub**.
  - Production costs will rise until 2030 in order to produce sufficient natural gas.
- America has large reserves of cheap natural gas in Appalachia and West Texas, which use pipelines to move across the country.
- Without new natural gas pipeline capacity, prices will grow as supply cannot meet demand.
- CRA's scenario prevented pipeline capacity expansion in the Southeast, including expanding major pipelines that connect Henry Hub to the Appalachian gas plays.
  - Higher gas prices resulted in more expensive power prices and more expensive retail rates compared to the CRA Reference case.

Except for TETCO M1 24, all basis points in the Southeast see larger increases in prices than Henry Hub in API's Scenario

API Scenario Premium vs CRA Reference Case ($/MMBtu)

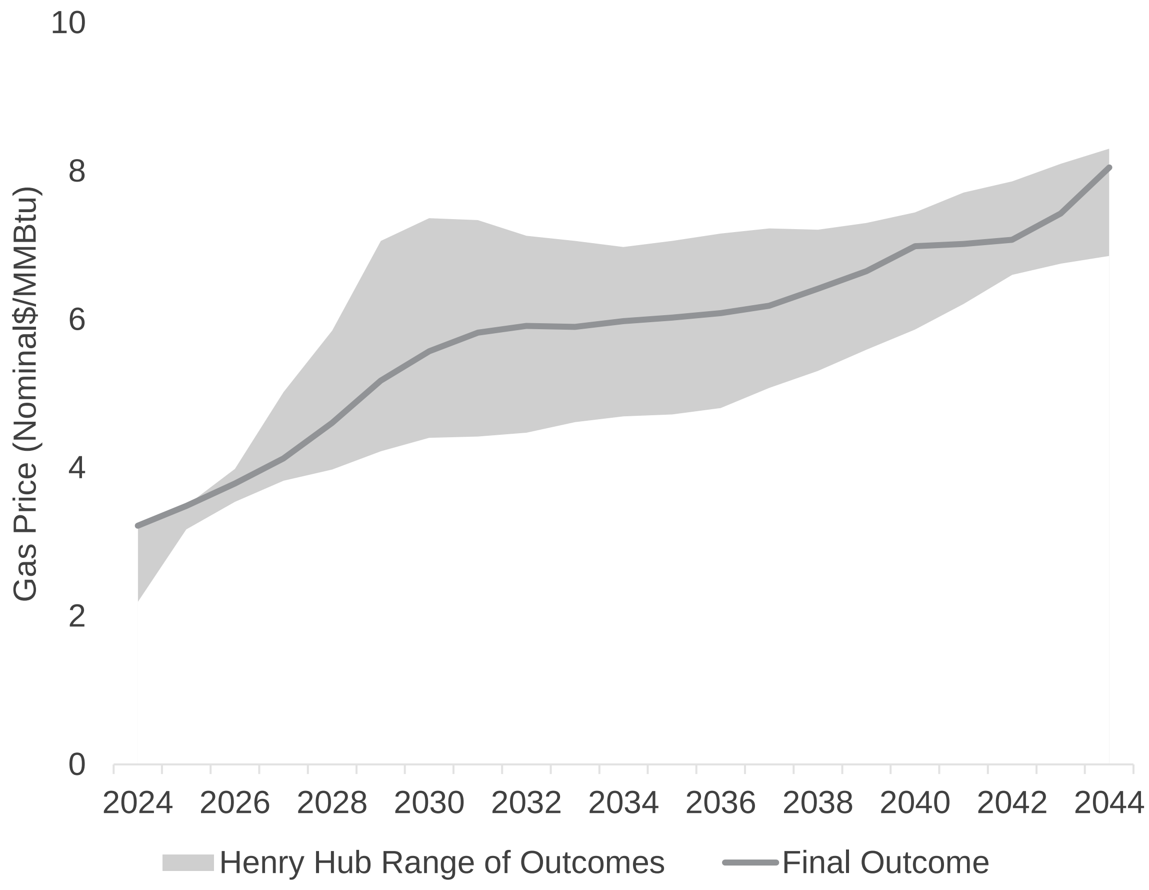


API Scenario Premium vs CRA Reference Case ($/MMBtu)

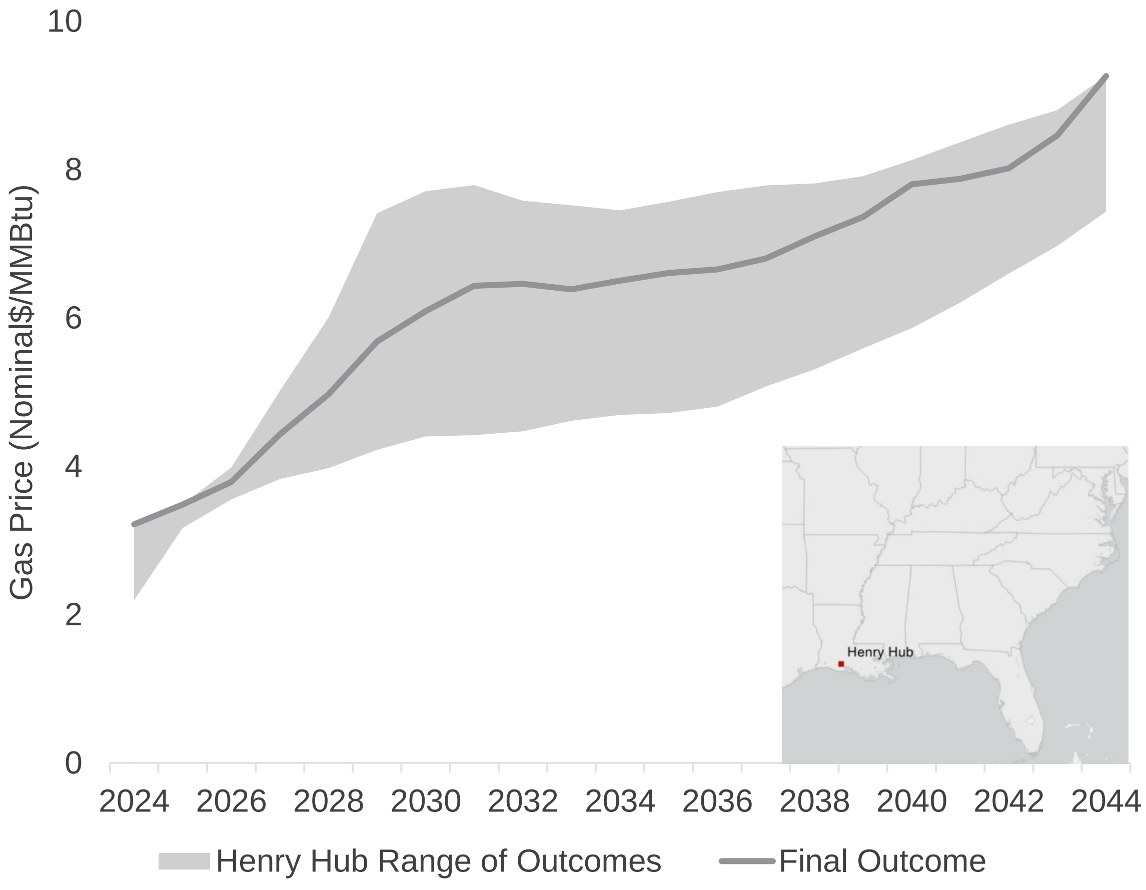
	Henry Hub	Transco Z4	Transco Z5	FGT Z3	TETCO M1 24
2024	0.00	0.00	0.00	0.00	0.00
2025	0.00	0.00	0.00	0.00	0.00
2026	0.00	0.00	0.00	0.00	0.00
2027	0.31	0.30	0.31	0.31	0.31
2028	0.37	0.36	0.44	0.35	0.30
2029	0.51	0.52	0.63	0.51	0.43
2030	0.52	0.53	0.65	0.52	0.44
2031	0.61	0.63	0.75	0.62	0.53
2032	0.55	0.57	0.70	0.56	0.46
2033	0.49	0.51	0.64	0.51	0.39
2034	0.53	0.55	0.68	0.54	0.42
2035	0.58	0.60	0.74	0.59	0.47
2036	0.57	0.59	0.73	0.58	0.46
2037	0.62	0.64	0.78	0.63	0.50
2038	0.68	0.72	0.94	0.71	0.57
2039	0.71	0.75	0.97	0.74	0.59
2040	0.81	0.86	1.10	0.84	0.68
2041	0.86	0.91	1.15	0.89	0.72
2042	0.95	1.00	1.27	0.98	0.81
2043	1.04	1.09	1.37	1.07	0.90
2044	1.21	1.27	1.58	1.25	1.03

CRA's analysis provided a wide range for Henry Hub prices; the API Scenario saw higher prices and a wider spread

Reference case Henry Hub price range ($/MMBtu)

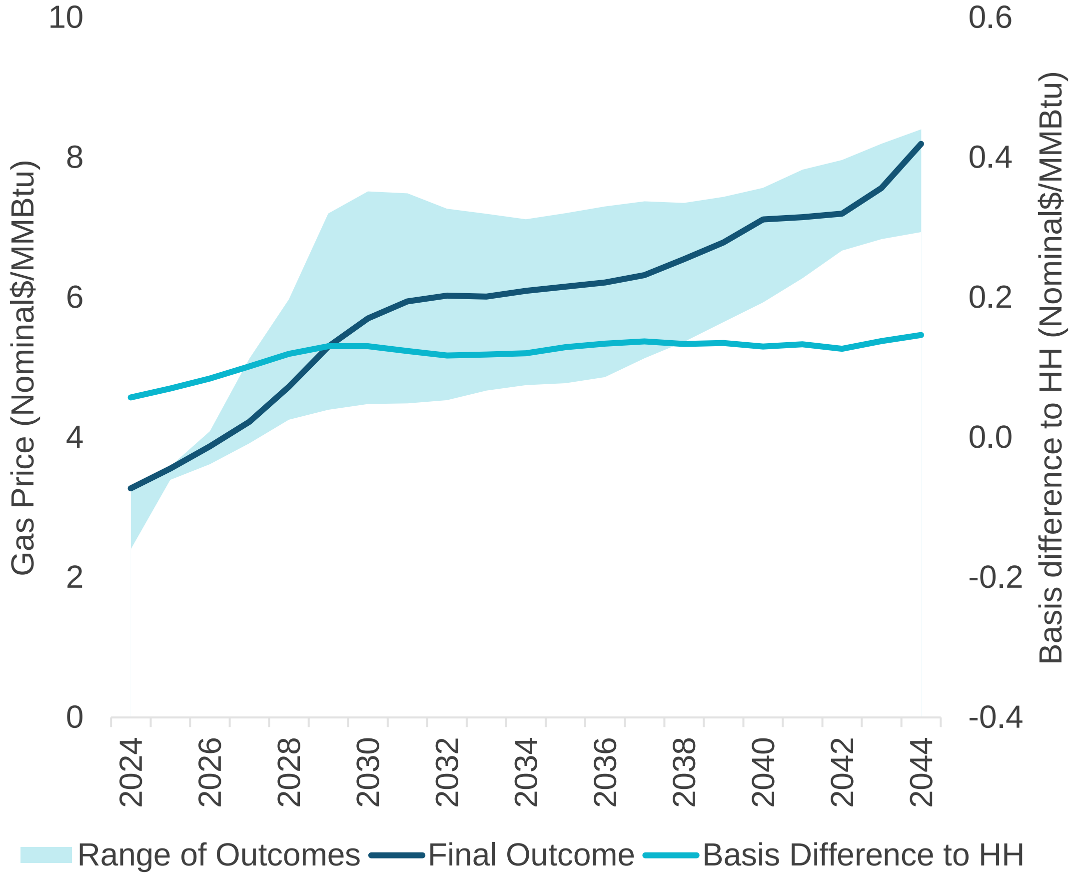


Scenario Case Henry Hub price range ($/MMBtu)

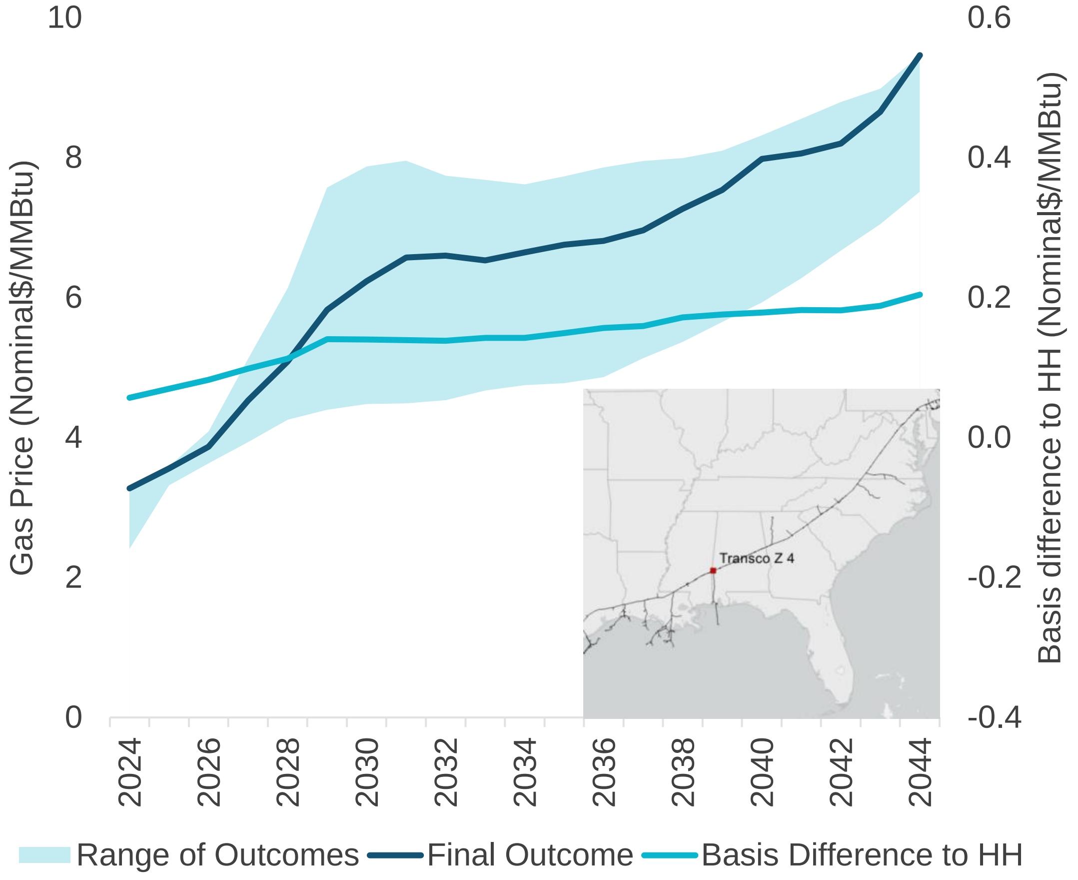


The lack of pipeline capacity expansion on Transco in the API scenario results in a higher basis difference to Henry Hub

Reference case Transco Z4 price range ($/MMBtu)

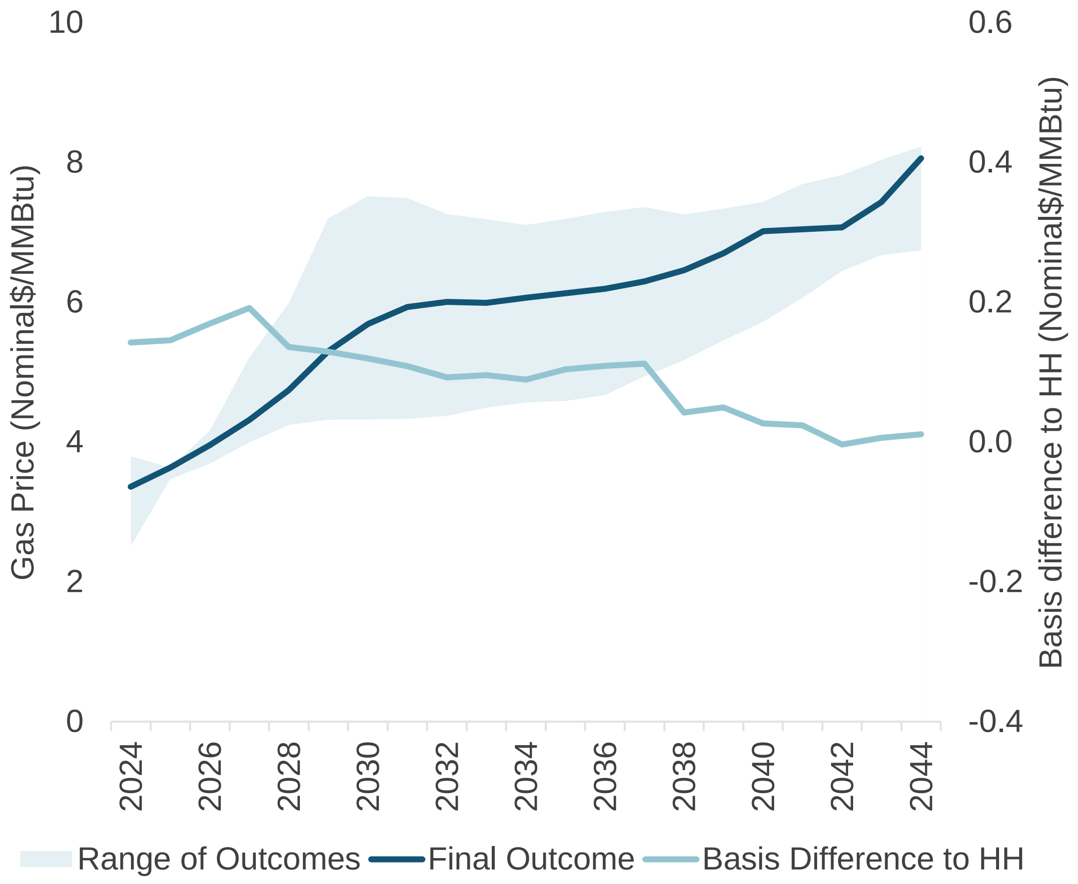


Scenario Transco Z4 price range ($/MMBtu)

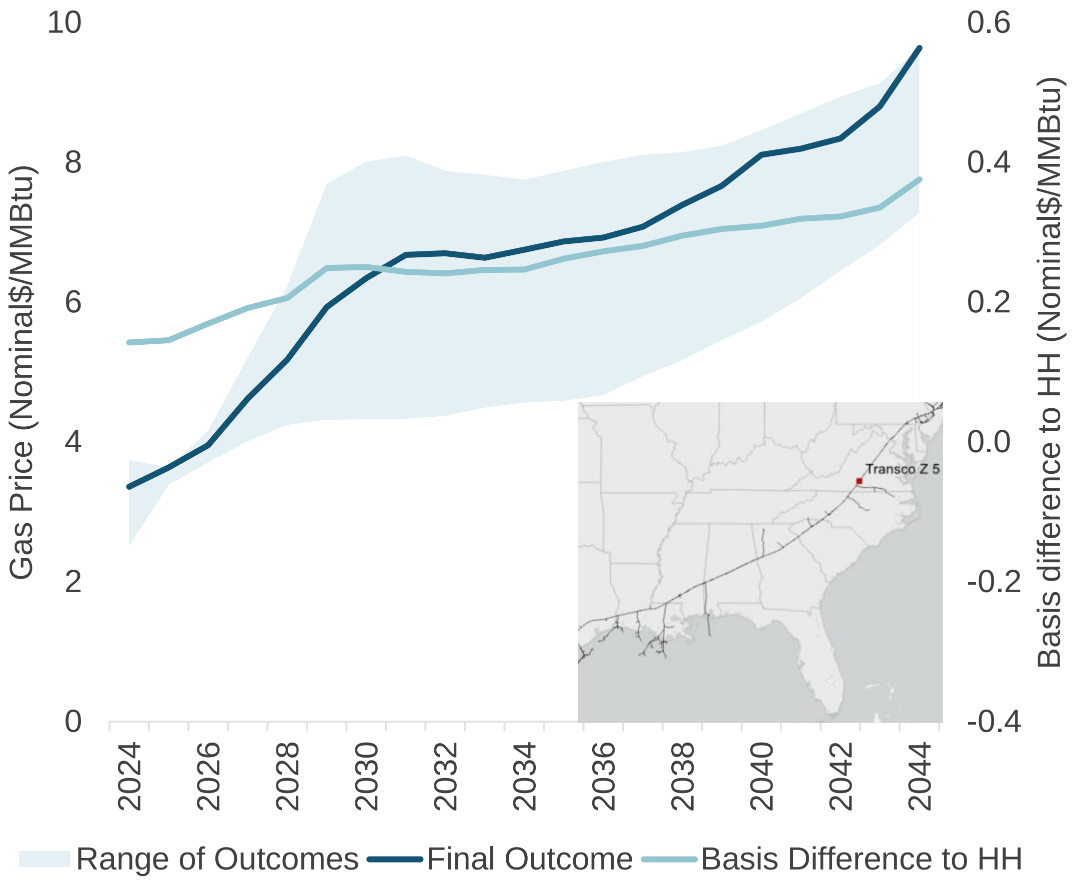


The inability to expand connection to the Marcellus and Utica in the scenario results in higher prices in the API Scenario

Reference case Transco Z5 price range ($/MMBtu)

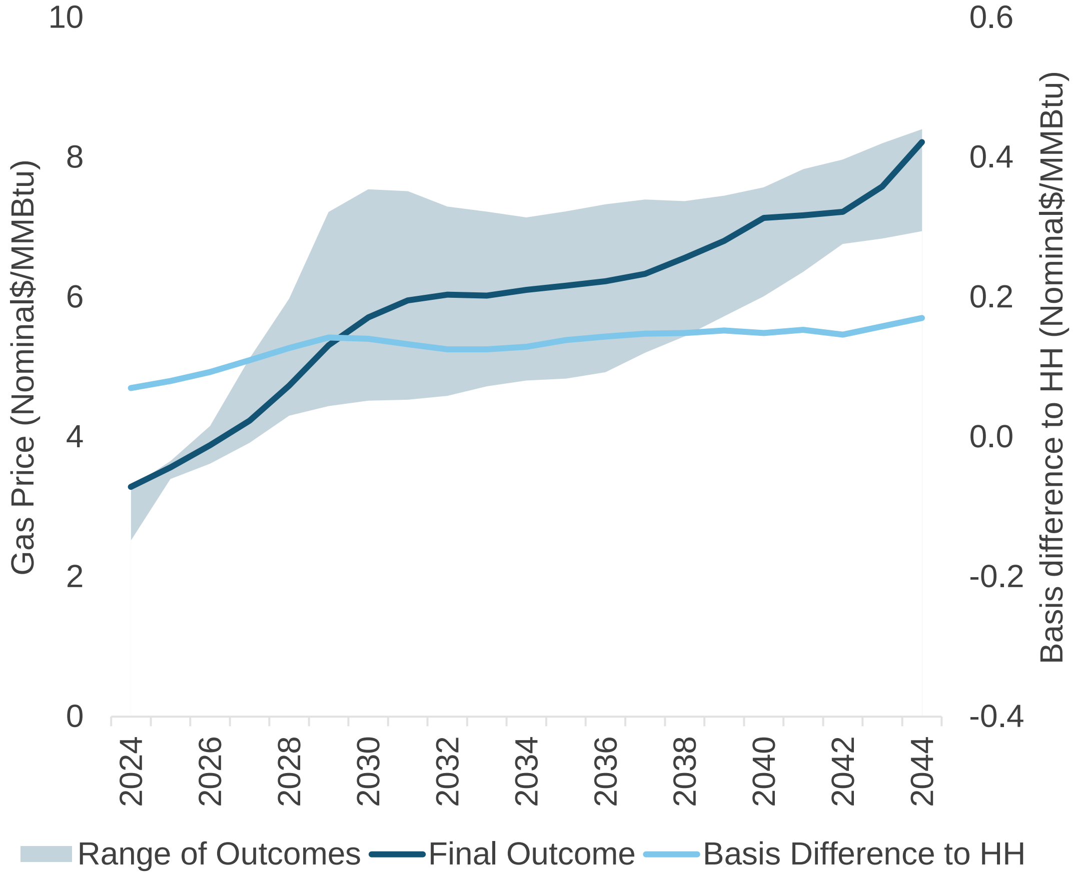


Scenario Transco Z5 price range ($/MMBtu)

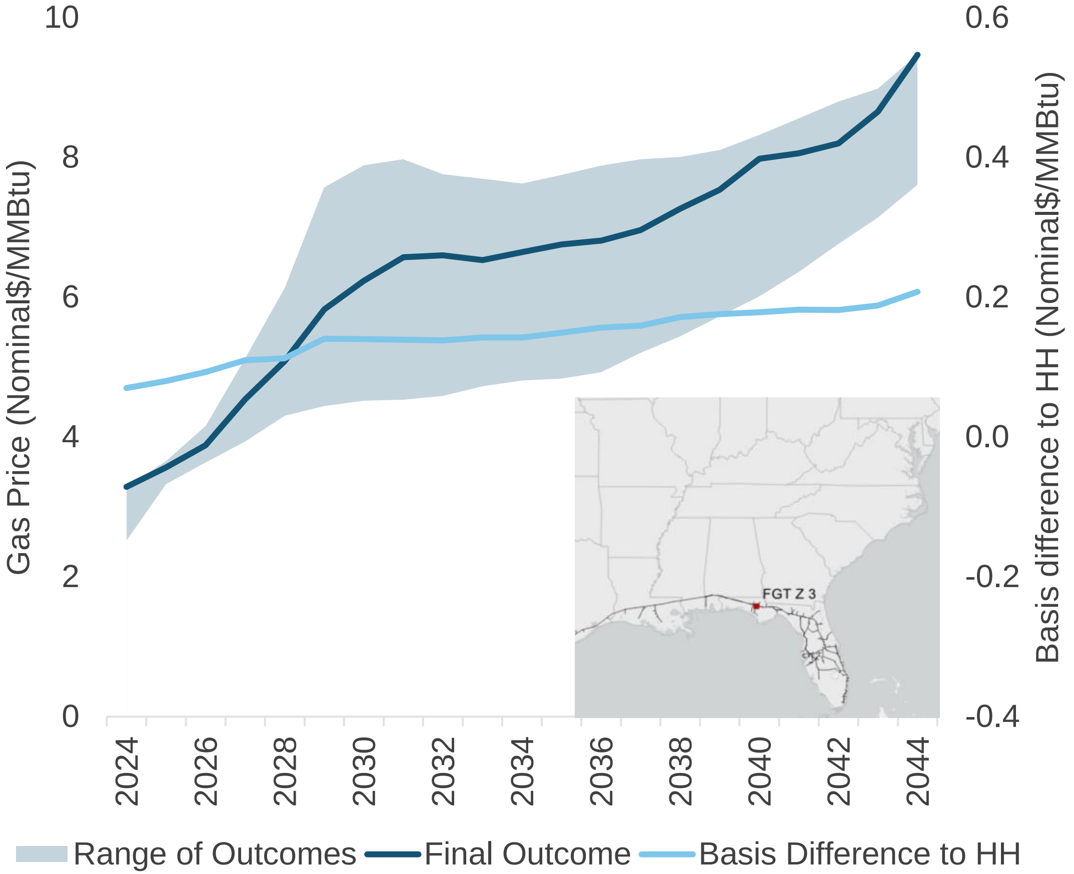


Florida Gas Transmission is not directly affected in the API Scenario constraints and so only sees slightly higher prices

Reference case FGT Z3 price range ($/MMBtu)

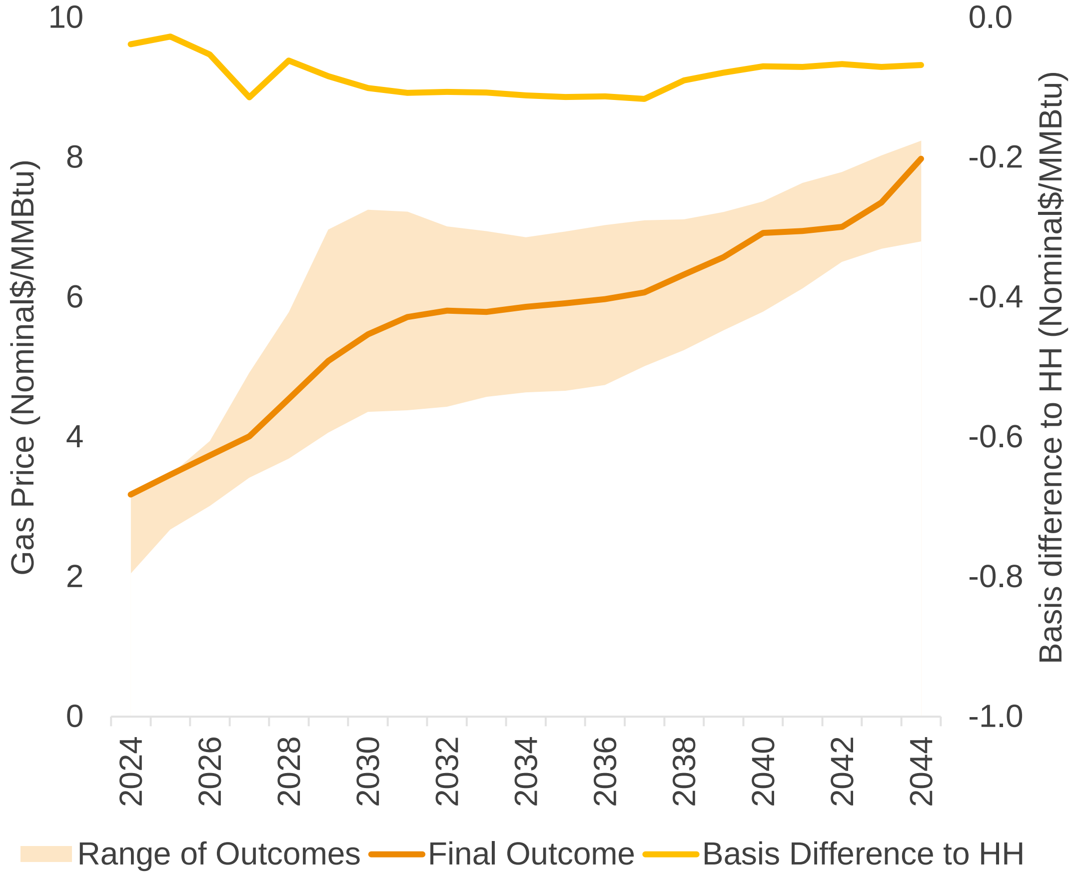


Scenario FGT Z3 price range ($/MMBtu)

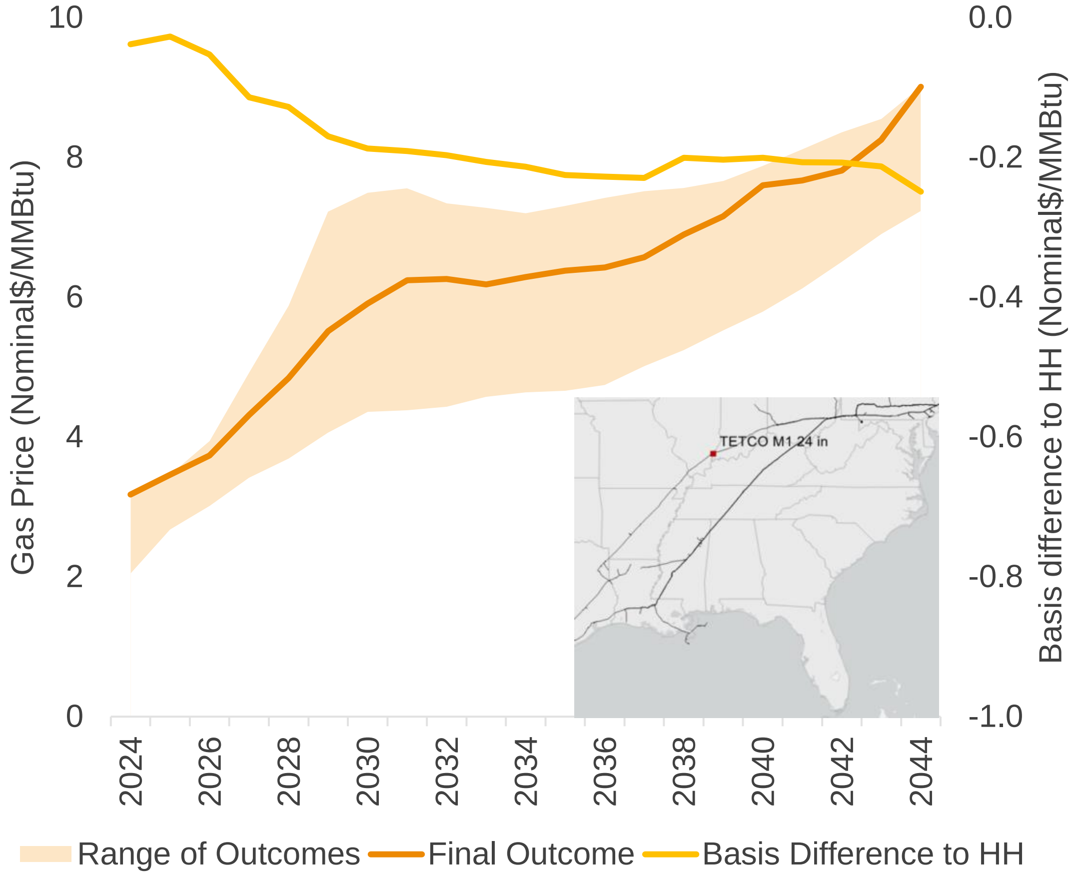


TETCO M1 24 bypasses TN and KY, so its pipeline capacity grows more in the API Scenario, lowering its basis difference to HH

Reference case TETCO M1 24 price range ($/MMBtu)



Scenario TETCO M1 24 price range ($/MMBtu)



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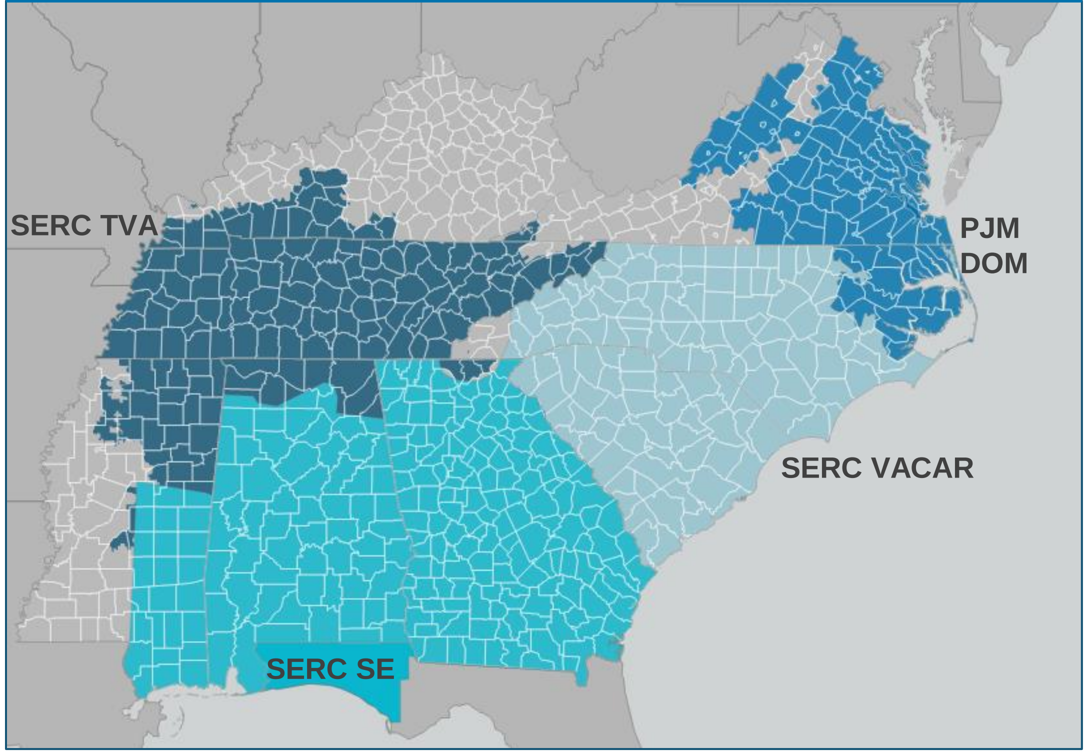
CRA's outlook of the Southeast power sector is modeled on the service territories of the main utilities and balancing authorities

Map of Electric Service Territories in Analysis



Key Notes

SERC TVA
- Tennessee Valley Authority

SERC SE (Southeast)
- Georgia Power
- Alabama Power
- Mississippi Power

SERC VACAR
- Duke Energy Carolinas
- Duke Energy Progress

PJM Dom (Dominion)
- Dominion Energy (Virginia Electric Company)

- In addition to the main utilities, CRA also modelled the other utilities, municipalities, and co-ops in these regions.

* Source: S&P Global

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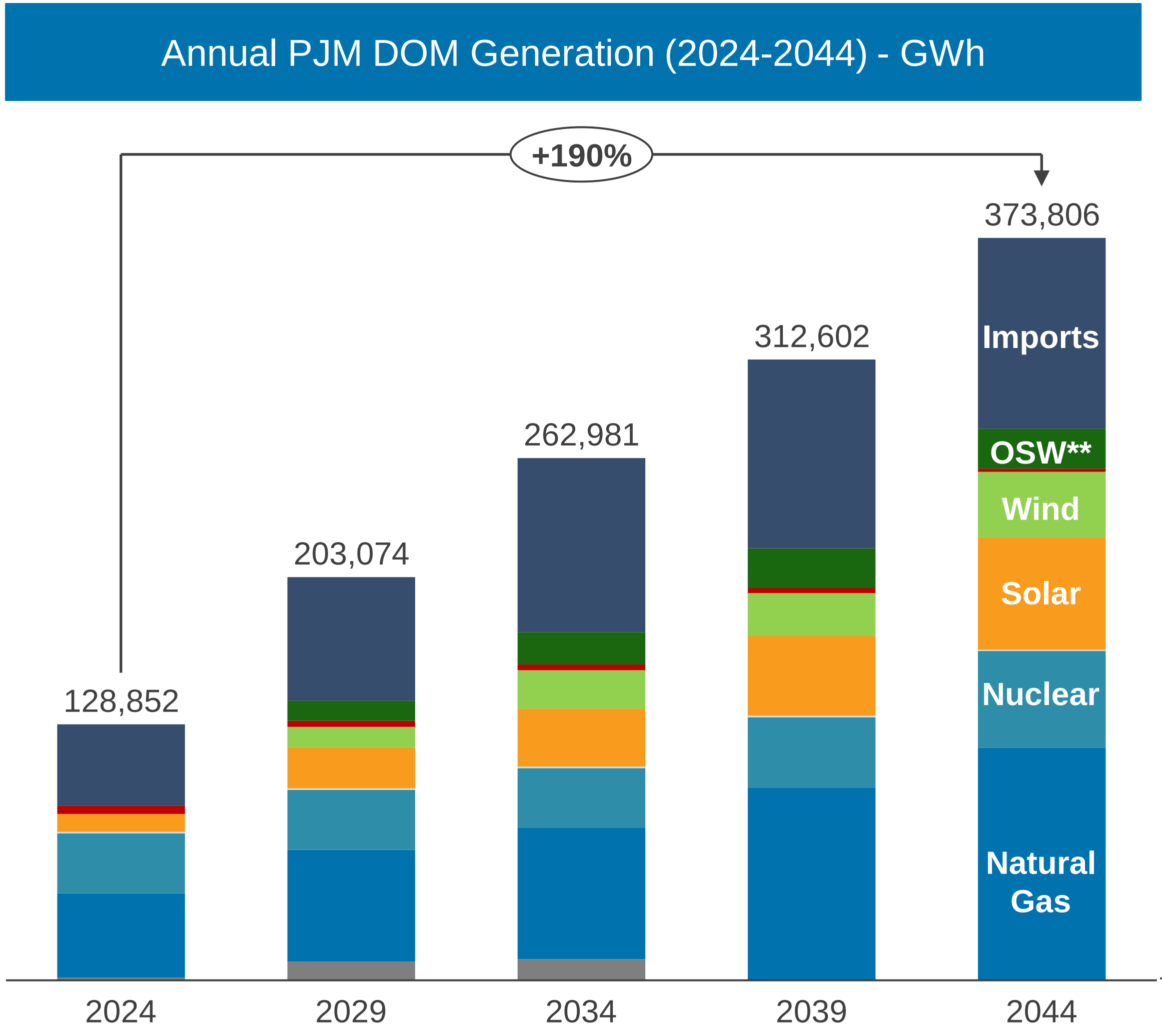
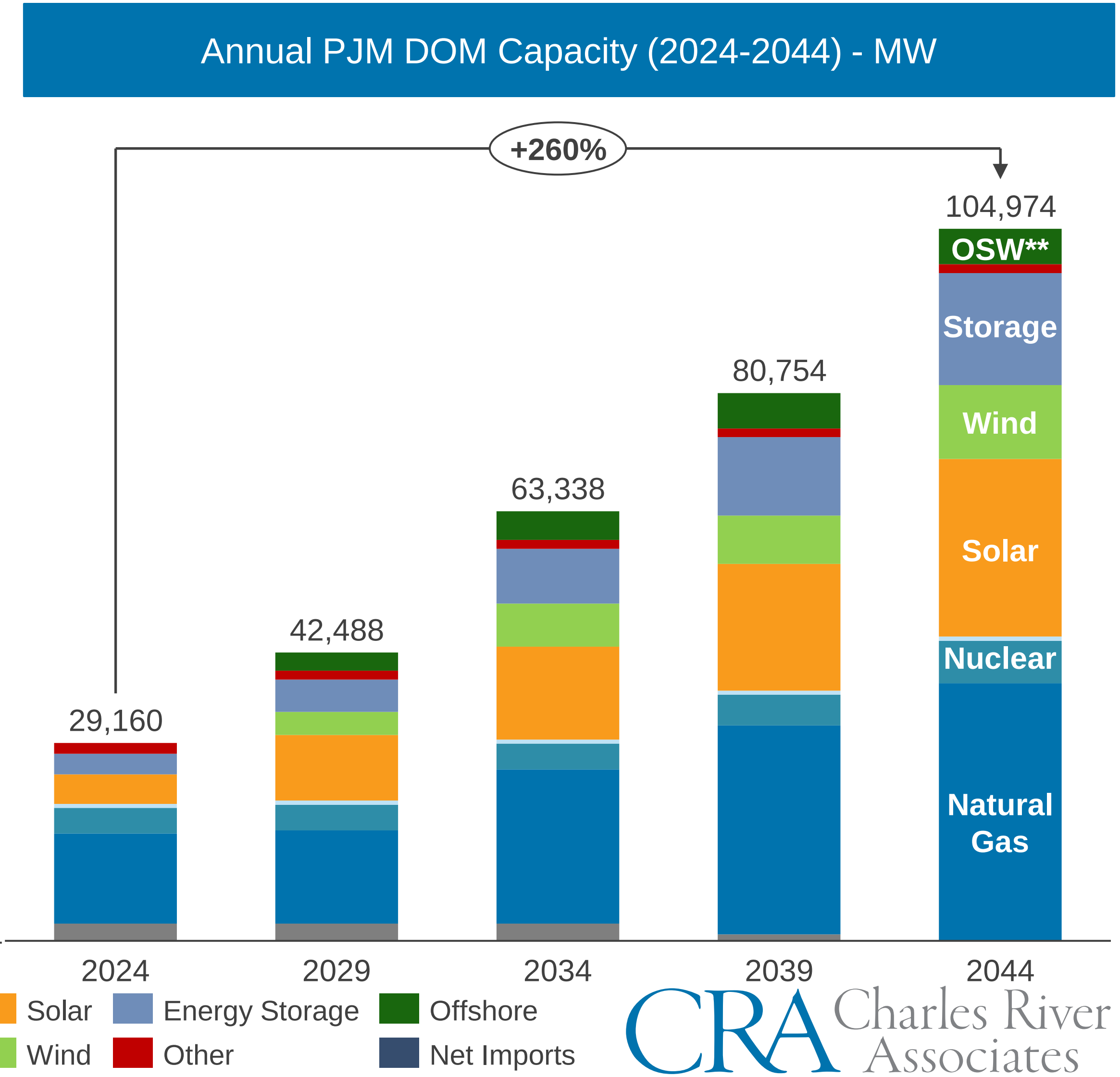
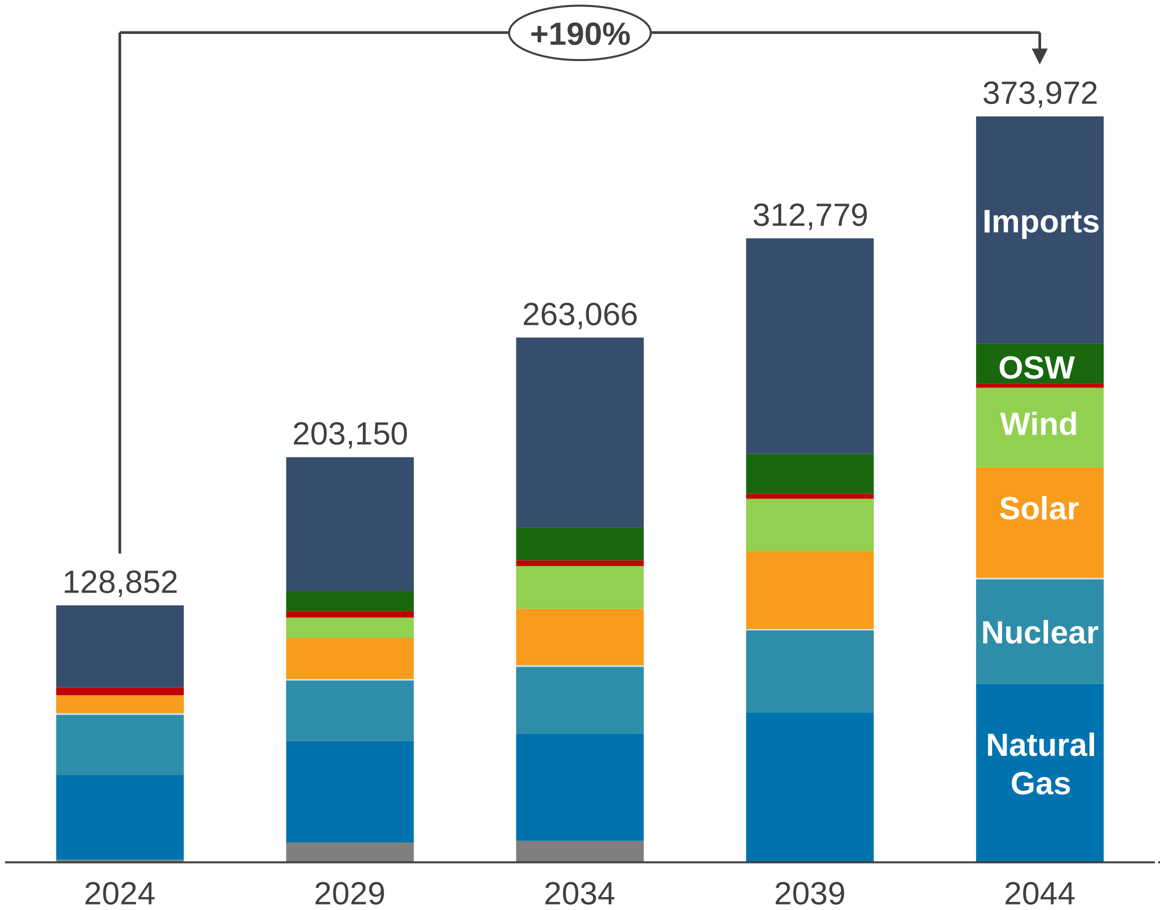
PJM DOM's capacity growth is driven by data center demand; CRA's expansion is in line with recent studies by the JLARC*

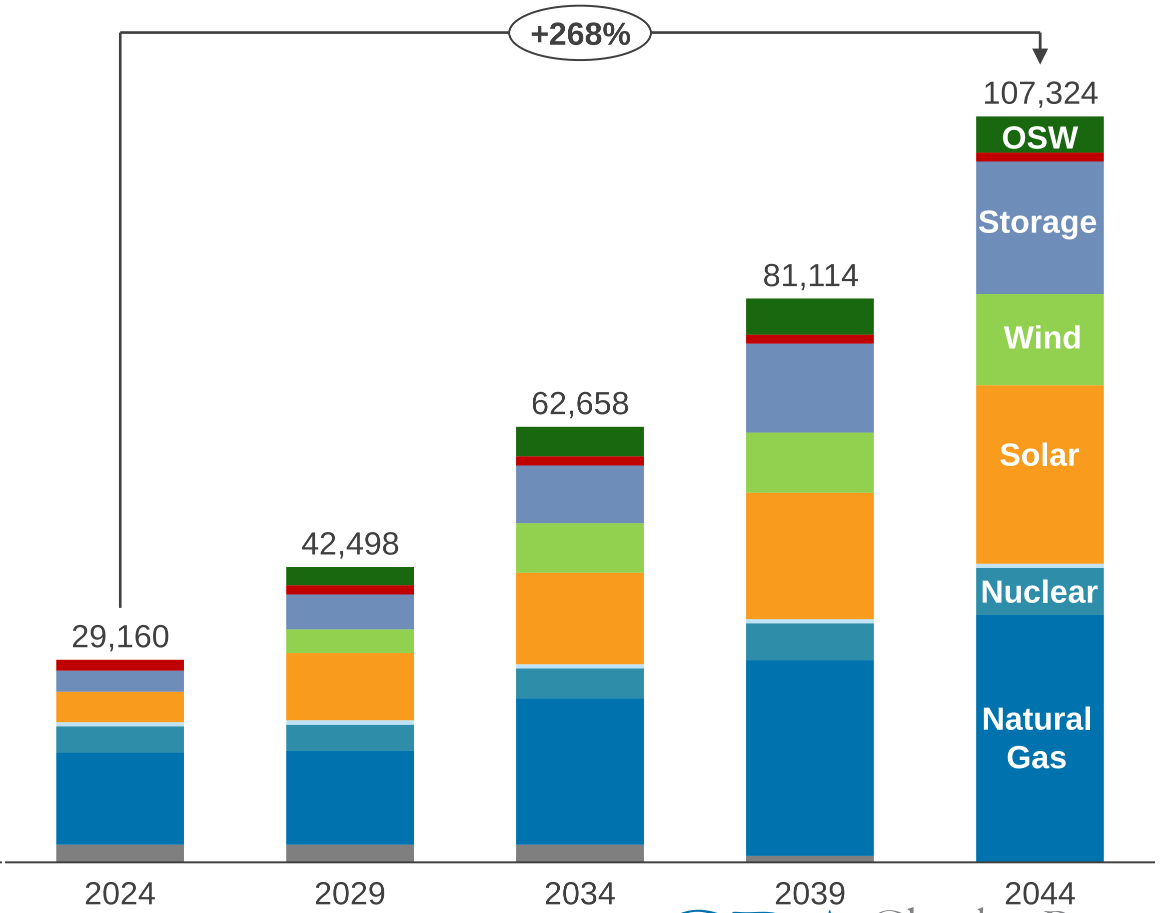




* Data Centers in Virginia Report Dec, 2024, (JLARC)
** Offshore Wind

The API Scenario has more imports and renewable capacity than the CRA Reference case to offset the higher gas prices

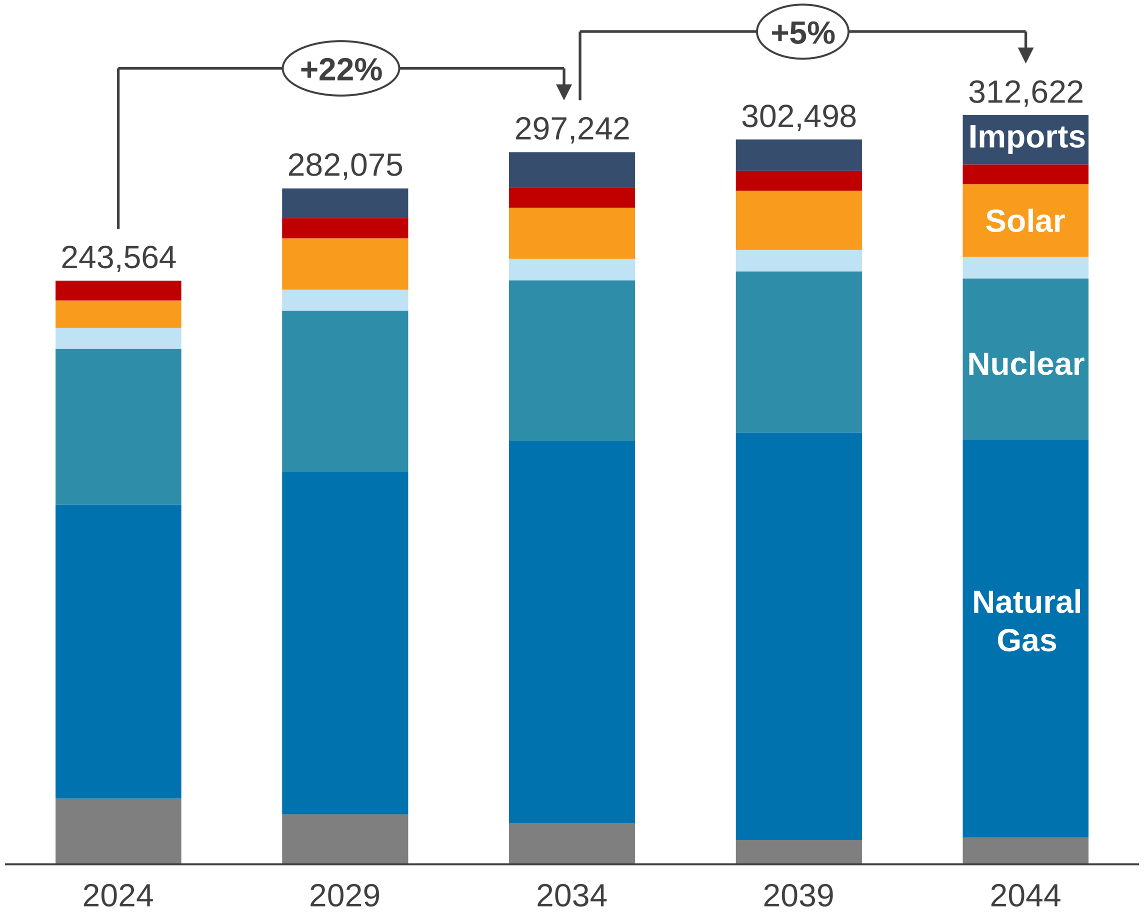




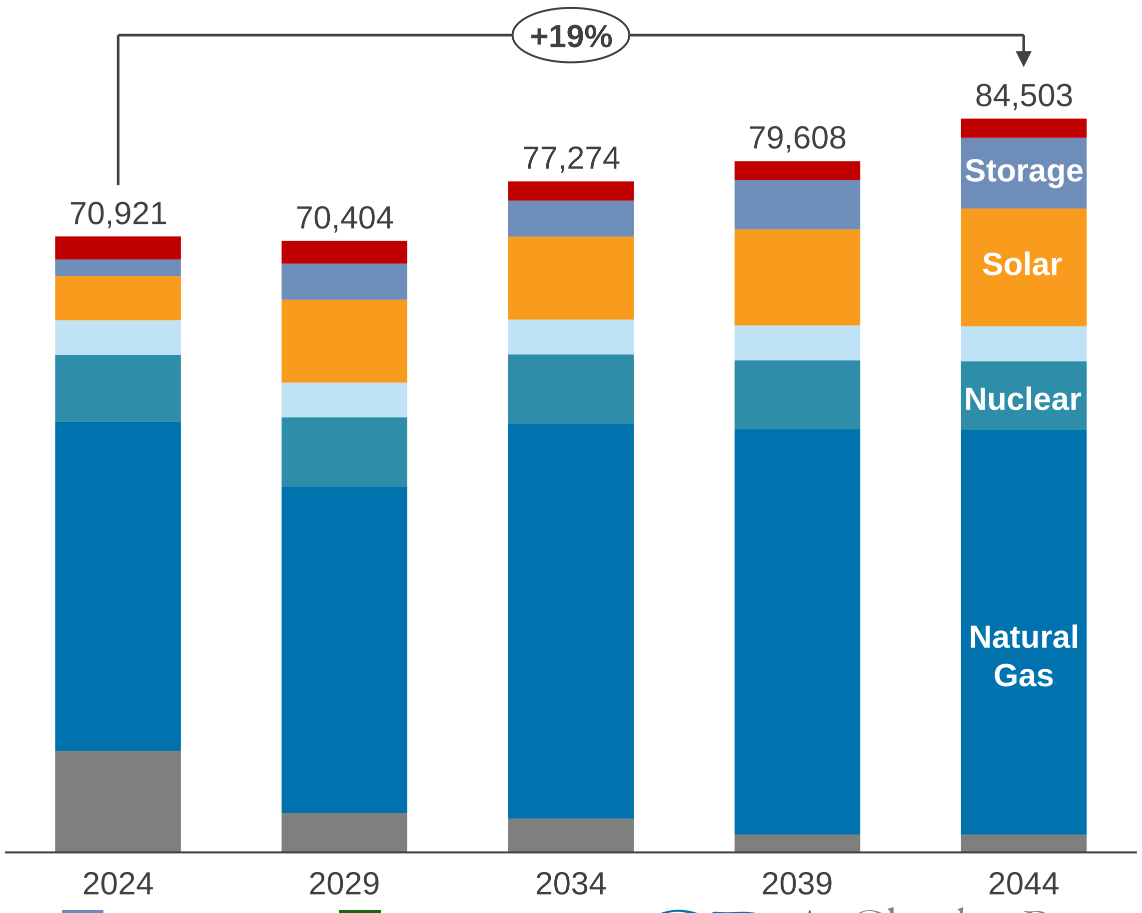
Coal Oil Biomass Solar Energy Storage Offshore
Gas Nuclear Hydro Wind Other Net Imports

SERC SE's demand growth is concentrated in the near term and has the heaviest reliance on natural gas of all regions

SERC SE Generation (2024-2044) - GWh



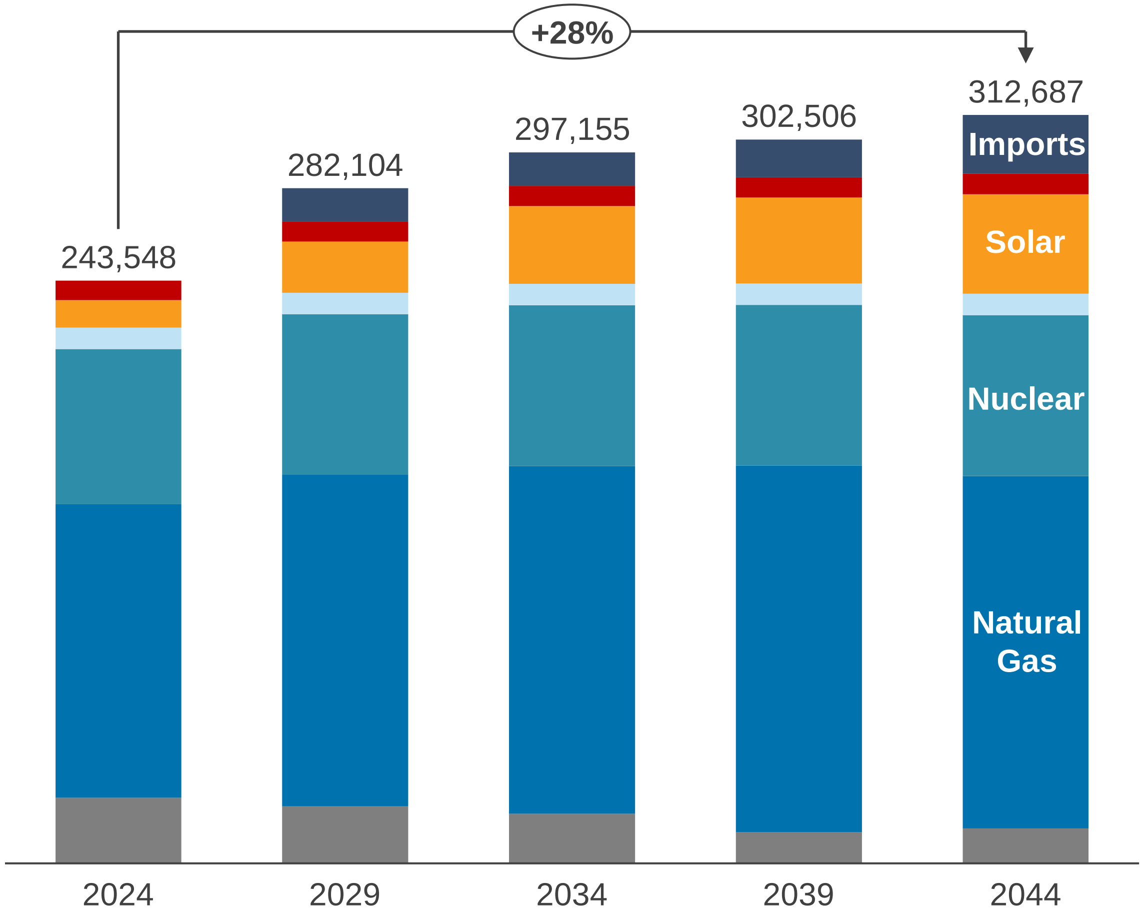
SERC SE Capacity (2024-2044) - MW



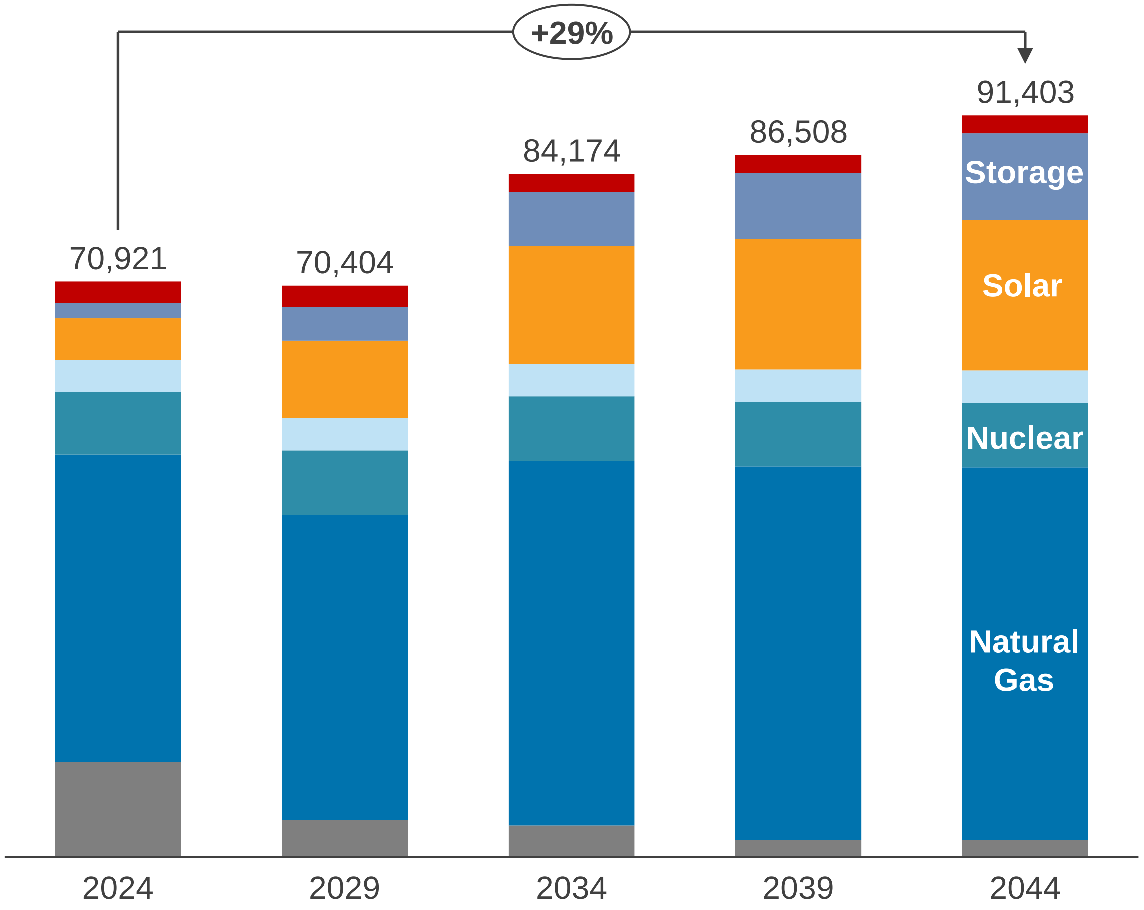
Coal | Oil | Biomass | Solar | Energy Storage | Offshore
Gas | Nuclear | Hydro | Wind | Other | Net Imports

SERC SE sees a larger buildout of solar PV and storage in API's Scenario to offset the higher gas prices

SERC SE Generation (2024-2044) - GWh



SERC SE Capacity (2024-2044) - MW

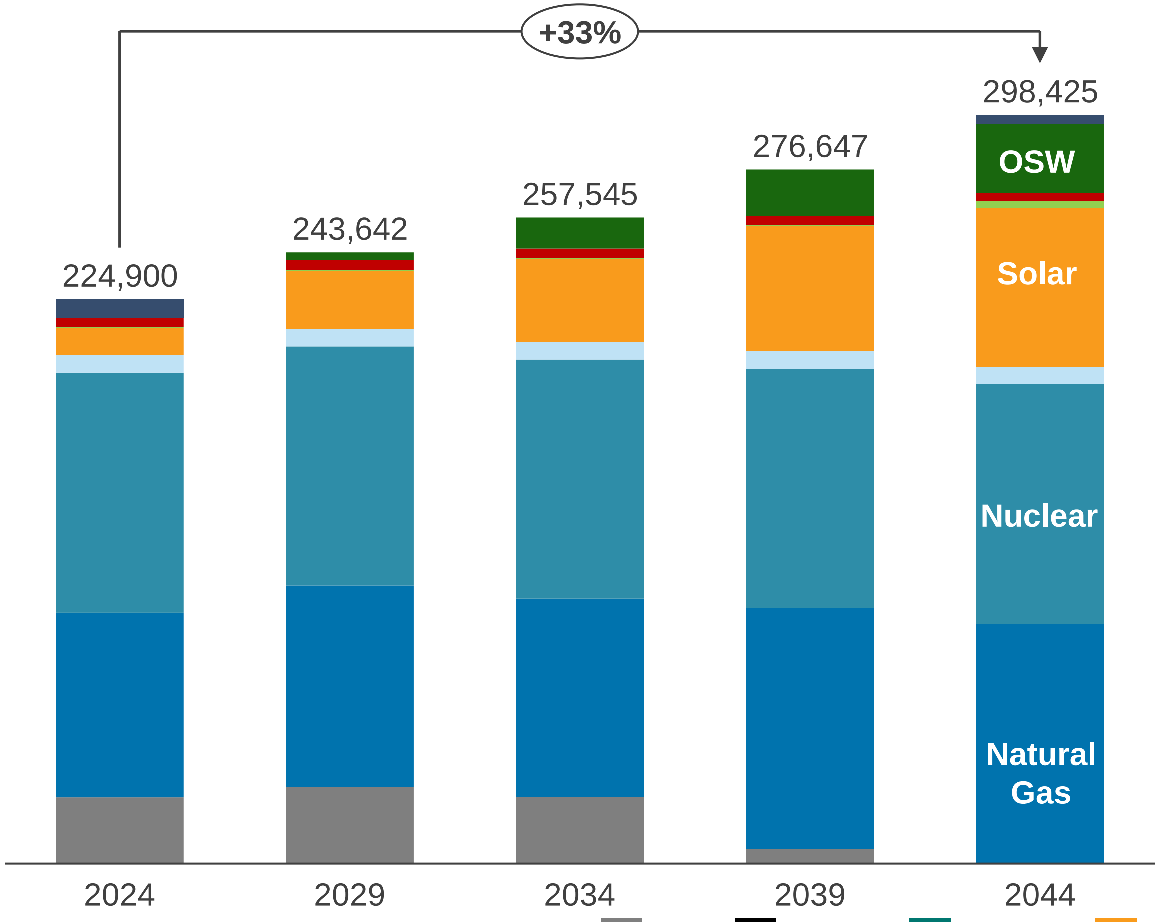


Coal | Oil | Biomass | Solar | Energy Storage | Offshore
Gas | Nuclear | Hydro | Wind | Other | Net Imports

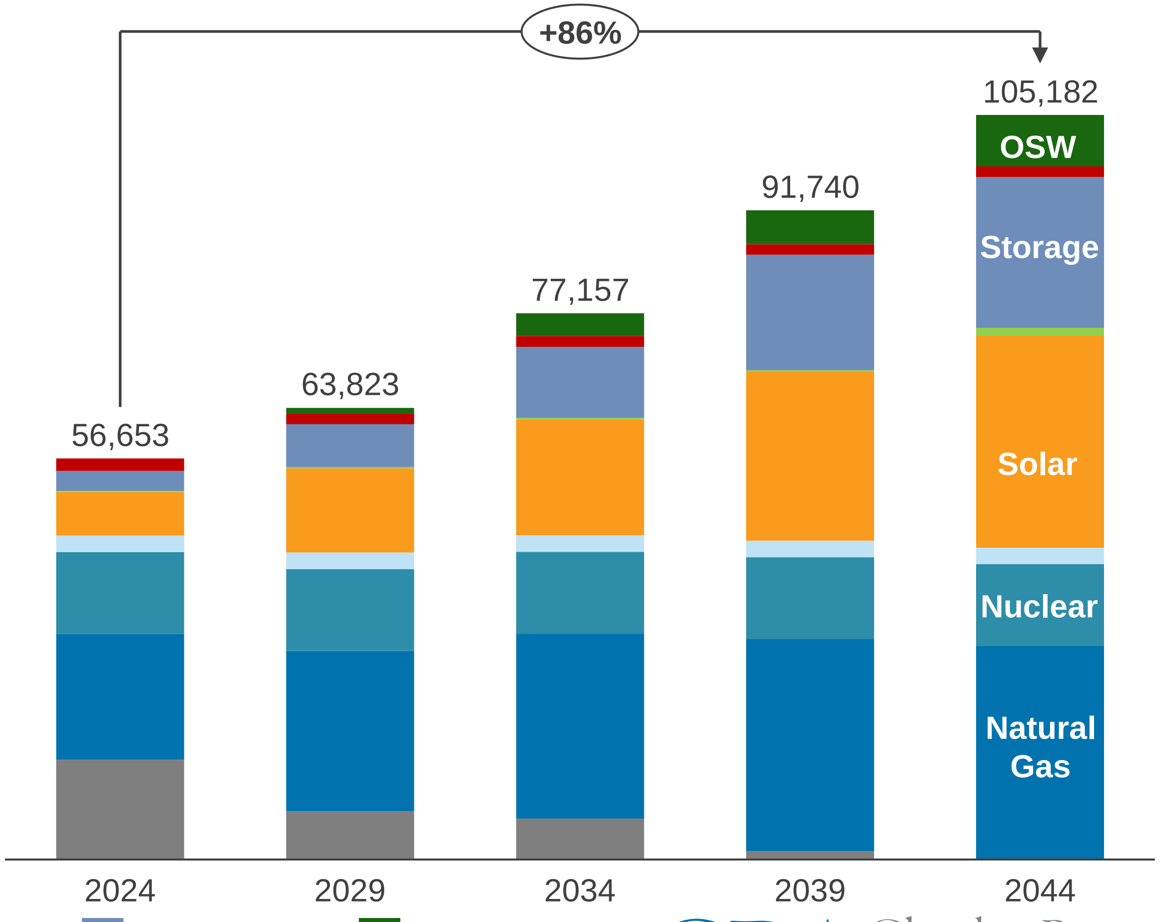
CRA Charles River Associates

CRA believes that there will be strong growth in solar PV and offshore wind in the Carolinas in both cases

SERC VACAR Generation (2024-2044) - GWh



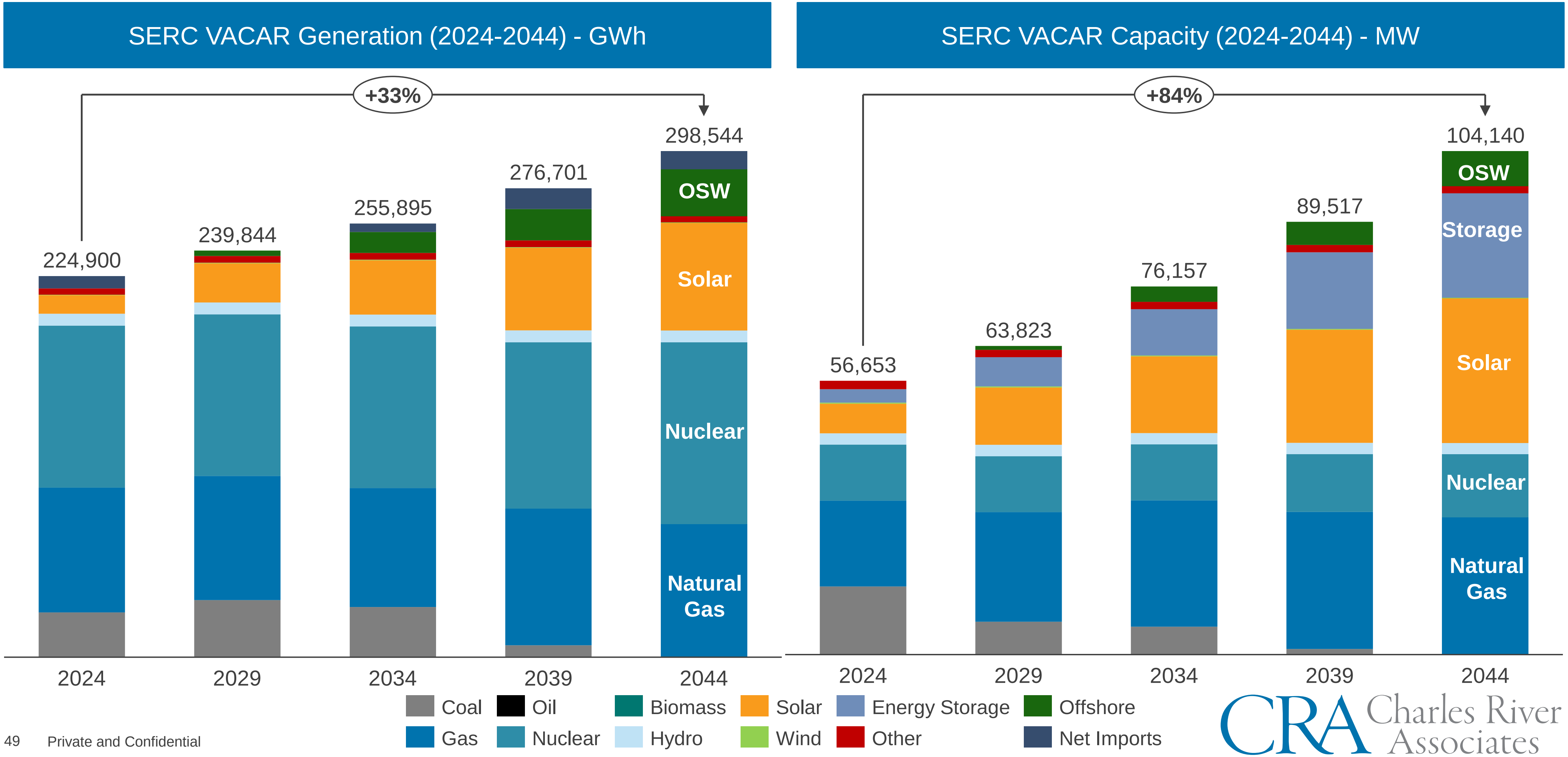
SERC VACAR Capacity (2024-2044) - MW



Coal | Oil | Biomass | Solar | Energy Storage | Offshore
Gas | Nuclear | Hydro | Wind | Other | Net Imports

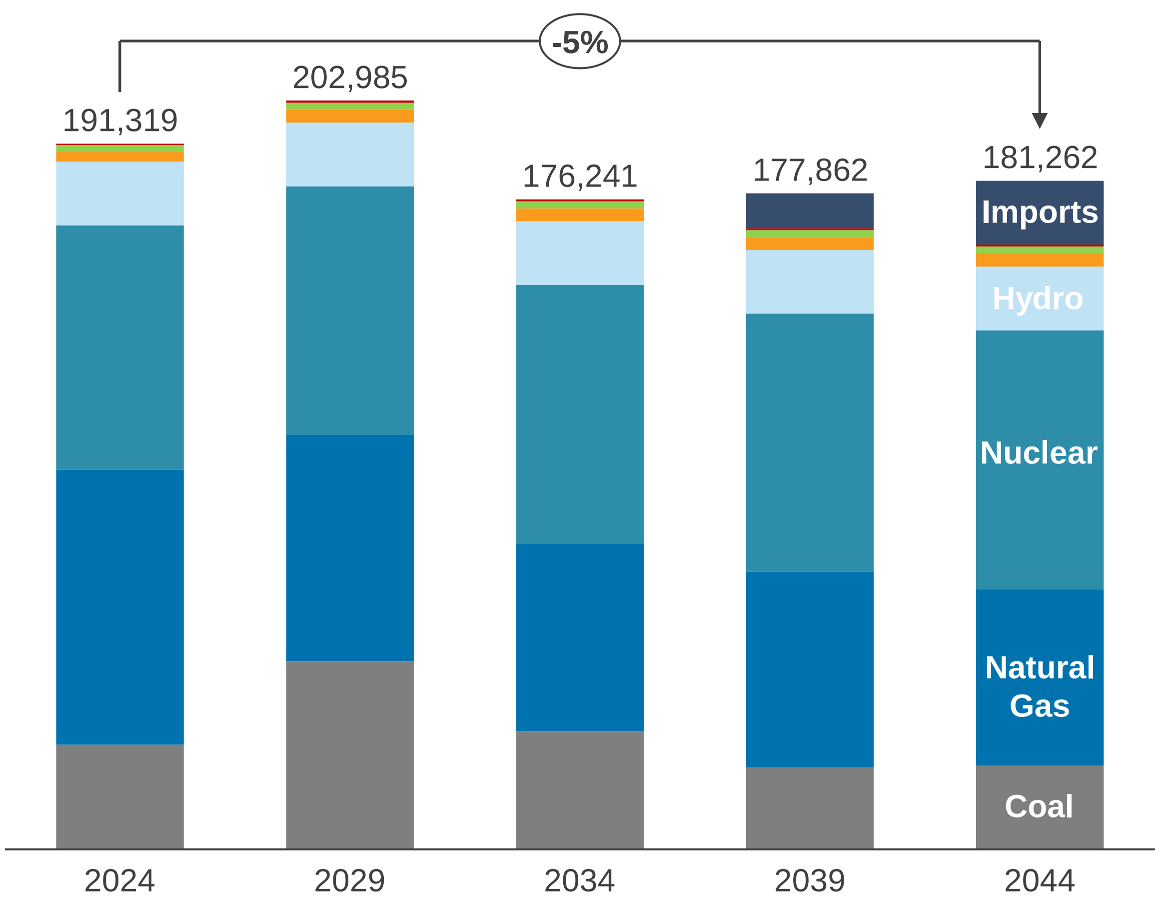
CRA Charles River Associates

The Carolinas has a similar buildout between cases, but the Scenario sees less gas generation than the Reference case

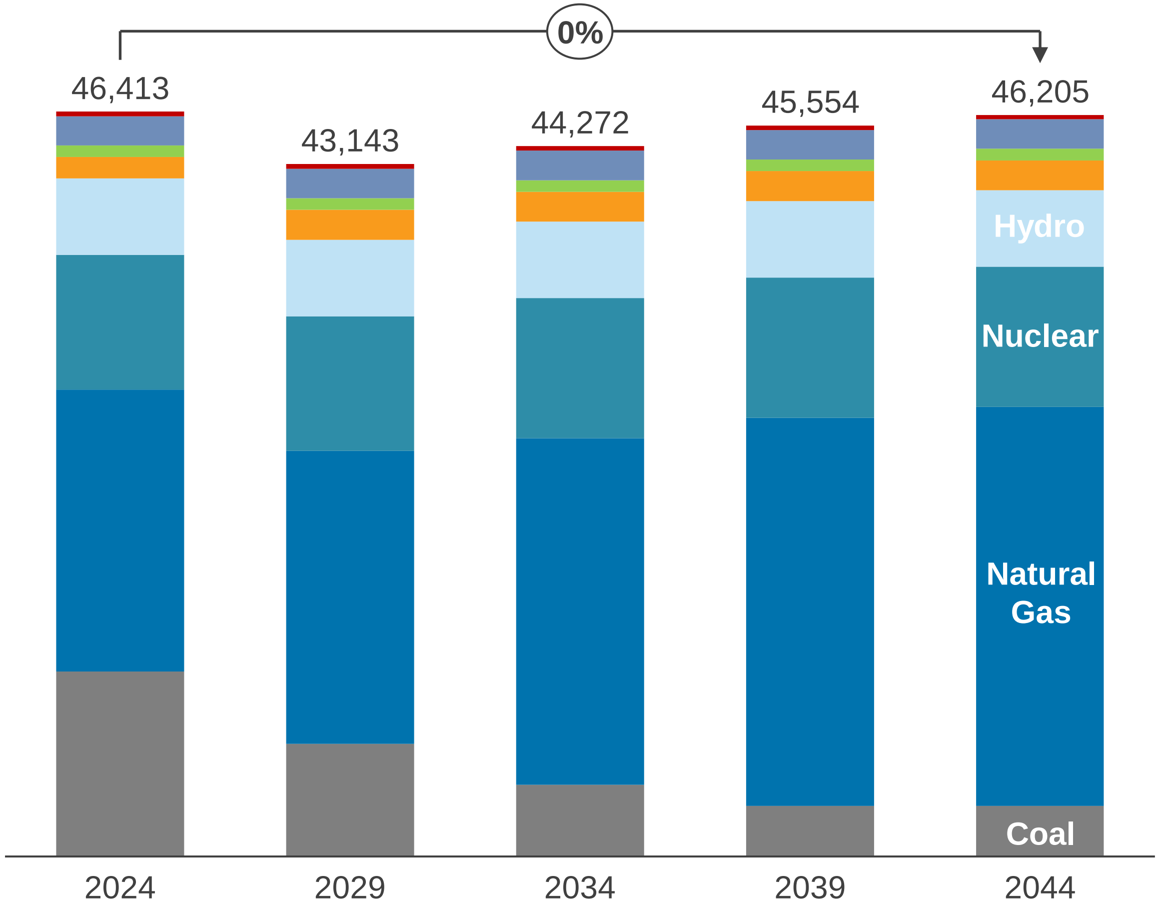


SERC TVA comes to rely on imports in the long term, having traditionally been an exporter of energy

SERC TVA Generation (2024-2044) - GWh



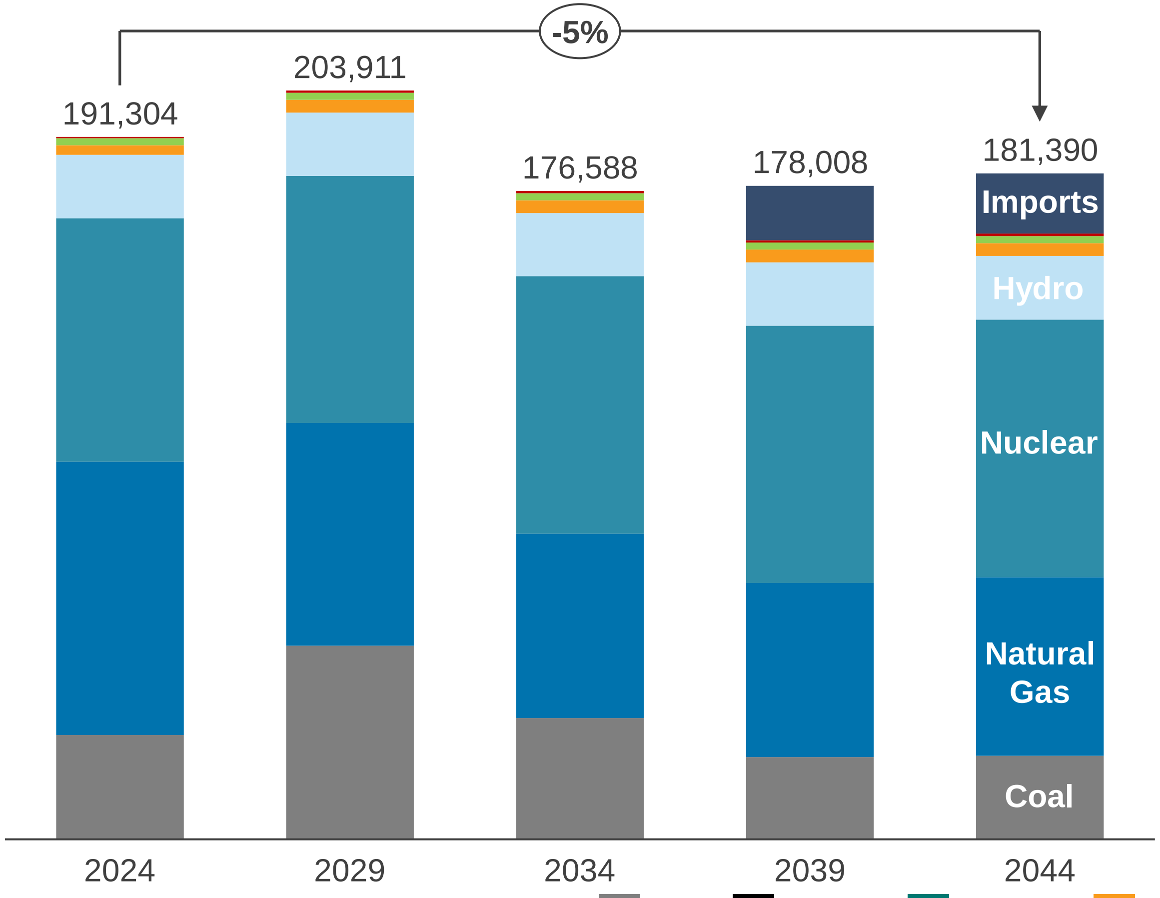
SERC TVA Capacity (2024-2044) - MW



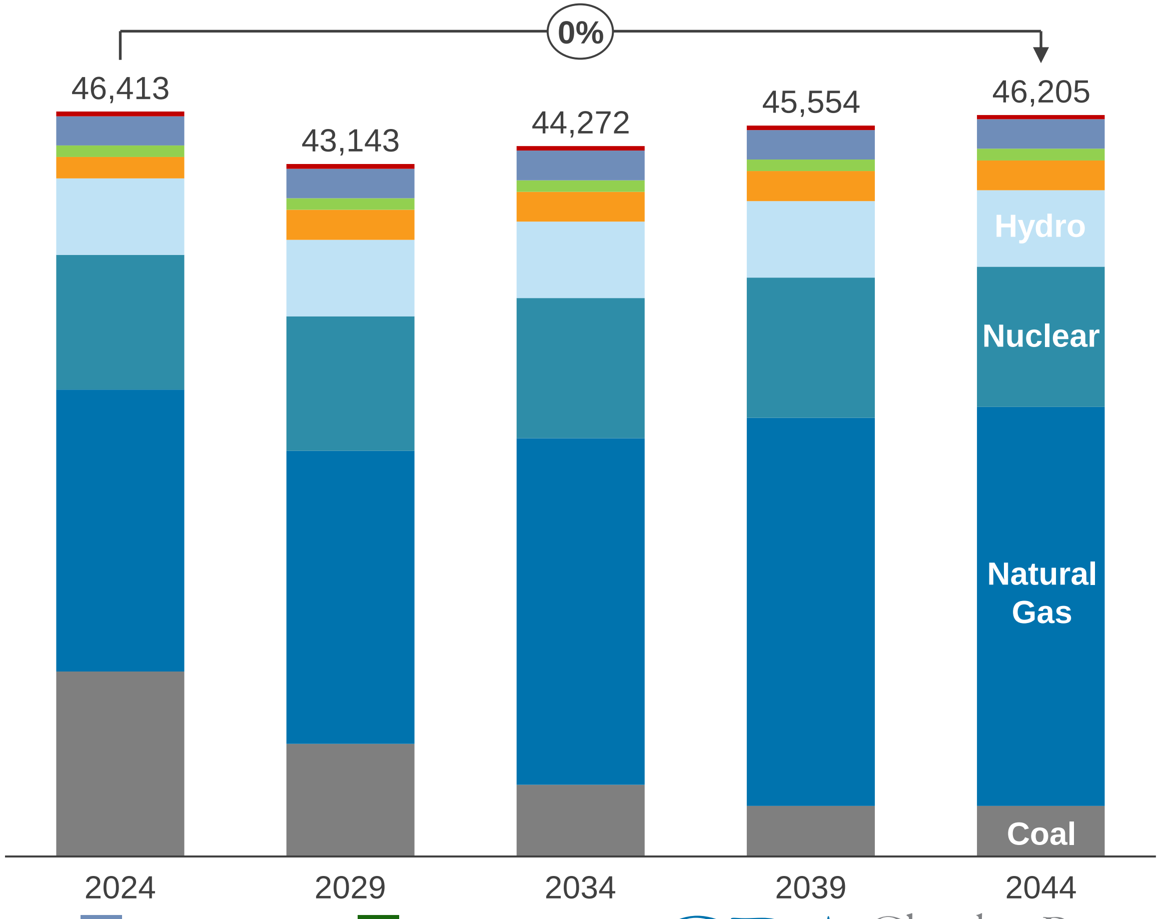
Coal, Oil, Biomass, Solar, Energy Storage, Offshore, Gas, Nuclear, Hydro, Wind, Other, Net Imports

Given its low load growth, TVA does not see many resource additions beyond maintaining its reliability requirements

SERC TVA Generation (2024-2044) - GWh



SERC TVA Capacity (2024-2044) - MW



Coal, Oil, Biomass, Solar, Energy Storage, Offshore
Gas, Nuclear, Hydro, Wind, Other, Net Imports

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The Typical American household in the Southeast of the US consumes 1,000kWh per month and pays between $125 and $150

Dominion Energy Summer 2023

Household Consumption	500 kWh	750 kWh	1000 kWh
Generation	$36.75	$54.63	$73.73
Transmission	$7.27	$10.83	$14.62
Distribution	$34.30	$46.78	$60.50
Total Rate	**$78.33**	**$112.24**	**$148.85**

Dominion Energy Winter 2024

Household Consumption	500 kWh	750 kWh	1000 kWh
Generation	$41.45	$62.69	$81.22
Transmission	$7.73	$11.72	$15.21
Distribution	$29.14	$39.84	$48.80
Total Rate	**$78.33**	**$114.24**	**$145.23**

Key Notes and Methodology

- Total Rates for each utility were obtained from Edison Electric Institute’s (EEI) *Typical Bills and Rates* reports for Summer 2023 and Winter 2024.
- Generation, Transmission, and Distribution components of the total rates for all utilities in the South Atlantic region were pulled from the EEI reports, as the utilities of concern do not report a full breakdown to EEI.
- To estimate the Generation, Transmission, and Distribution components of the Total Rates of each utility presented, the average ratio of each component in the South Atlantic region was multiplied by the Total Rate of the given utility for each level of household consumption.
- The total rate varies based upon the amount of energy consumed each month.
- As demand in Dominion grows the share of the cost from generation grows since more electricity must be generated.
  - Generation costs include the cost to dispatch a power plant, the costs to build one, and the costs of financing construction.

* Sources: Edison Electric Institute, *Typical Bills and Average Rates Report*, Summer 2023 and Winter 2024
[EIA *Electricity Data Browser*]

Winter rates cover October – May and see higher Generation charges than the Summer period, but lower Distribution charges

Duke Energy Carolinas Summer 2023

Household Consumption	500 kWh	750 kWh	1000 kWh
Generation	$33.19	$48.56	$63.79
Transmission	$6.57	$9.63	$12.65
Distribution	$30.98	$41.58	$52.35
Total Rate	**$70.74**	**$99.76**	**$128.79**

Georgia Power Summer 2023

Household Consumption	500 kWh	750 kWh	1000 kWh
Generation	$37.15	$54.59	$78.61
Transmission	$7.35	$10.82	$15.59
Distribution	$34.67	$46.74	$64.51
Total Rate	**$79.17**	**$112.15**	**$158.71**

TVA Energy Summer 2023

Household Consumption	500 kWh	750 kWh	1000 kWh
Generation	$36.66	$52.55	$68.25
Transmission	$7.26	$10.42	$13.53
Distribution	$34.21	$44.99	$56.00
Total Rate	**$78.12**	**$107.96**	**$137.78**

Duke Energy Carolinas Winter 2024

Household Consumption	500 kWh	750 kWh	1000 kWh
Generation	$40.19	$58.95	$77.70
Transmission	$7.50	$11.02	$14.55
Distribution	$28.25	$37.46	$46.69
Total Rate	**$75.94**	**$107.43**	**$138.93**

Georgia Power Winter 2024

Household Consumption	500 kWh	750 kWh	1000 kWh
Generation	$42.00	$60.42	$78.77
Transmission	$7.83	$11.29	$14.75
Distribution	$29.53	$38.39	$47.34
Total Rate	**$79.36**	**$110.10**	**$140.86**

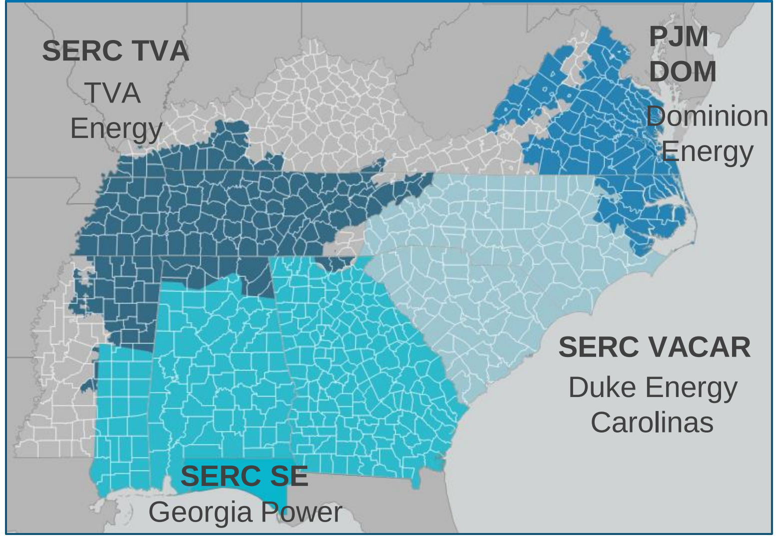
TVA Energy Winter 2024

Household Consumption	500 kWh	750 kWh	1000 kWh
Generation	$38.87	$55.39	$71.82
Transmission	$7.25	$10.35	$13.45
Distribution	$27.33	$35.20	$43.16
Total Rate	**$73.45**	**$100.94**	**$128.43**

Source: Edison Electric Institute, *Typical Bills and Average Rates Report*, Summer 2023 and Winter 2024

The total cost of electric service is determined by generation, transmission and distribution cost components

Map of Electric Service Territories in CRA Analysis



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- Total Rates for each utility were obtained from Edison Electric Institute's (EEI) *Typical Bills and Rates* reports for Summer 2023 and Winter 2024.
- Generation, Transmission, and Distribution components of the total rates for all utilities in the South Atlantic region were pulled from the EEI reports, as the utilities of concern do not report a full breakdown to EEI.
- To estimate the Generation, Transmission, and Distribution components of the Total Rates of each utility presented, the average ratio of each component in the South Atlantic region was multiplied by the Total Rate of the given utility.
- The total rate varies based upon the amount of energy consumed each month. CRA assumes average monthly consumption is 1,000 kWh.

Summer Rate using 1,000 kWh monthly

Bill Component	Dominion Energy	Duke Energy Carolinas	Georgia Power	TVA Energy
Generation	$73.73	$63.79	$78.61	$68.25
Transmission	$14.62	$12.65	$15.59	$13.53
Distribution	$60.50	$52.35	$64.51	$56.00
Total Rate	**$148.85**	**$128.79**	**$158.71**	**$137.78**

Winter Rate using 1,000 kWh monthly

Bill Component	Dominion Energy	Duke Energy Carolinas	Georgia Power	TVA Energy
Generation	$81.22	$77.70	$78.77	$71.82
Transmission	$15.21	$14.55	$14.75	$13.45
Distribution	$48.80	$46.69	$47.34	$43.16
Total Rate	**$145.23**	**$138.93**	**$140.86**	**$128.43**

* Sources: Edison Electric Institute, *Typical Bills and Average Rates Report*, Summer 2023 and Winter 2024, EIA *Electricity Data Browser*, *S&P Global*

Each region has different financial assumptions based upon factors such as the state tax rates and age of the fleet

Cost of Service Financial Assumptions				
	SERC TVA	SERC SE	SERC VACAR	PJM DOM
Average Gen Asset Life Remaining (yrs.)	17.8	22.4	21.3	20.6
Return on Equity	6.8%	10.5%	10.0%	9.7%
Cost of Debt	5%	5%	5%	5%
Federal Tax Rate	-	21%	21%	21%
State Tax Rate	-	5.75%	3.75%	6%
Blended Tax Rate	-	26%	24%	26%
Equity %	44%	56%	52%	52%

Key Notes

- Average Generating Asset Life Remaining reviews the average age of the fleet by fuel type and weights it relative to the capacity.
  - The more years remaining on the life of the fleet, the more costs still need to be paid.
- Return on Equity (ROE) is stated in each major utility's Integrated Resource Plan (IRP) and is agreed upon with state's Public Utility Commission (PUC).
- TVA has different reporting requirements from the other utilities as it is a federal agency and so required different methodology to determine.
  - See Annex 2 for more information.
- For regions made up of multiple states the state taxes were adjusted to account for the spread.
  - TVA does not pay state or federal taxes, but payments in lieu of taxes are assumed for TVA of 6.5%

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The generation costs are determined by the cost of operating the fleet and earning a return from and on the investment in the fleet

Components

- Capital Recovery:
  - Return of and on invested capital; and
  - Income taxes.
- Fixed operating & maintenance costs,
- Variable dispatch costs:
  - Fuel;
  - Emissions; and
  - Variable operating & maintenance costs.
- Imports and Exports:
  - Imported energy from outside the zone; and
  - Exports reduce system costs.
- Total Sales:
  - Quantity of MWh sold to customers.

Key Notes

- Both the CRA Reference case and API Scenario must meet the same demand, but do so by dispatching different resources at different costs and building different types of power plants at varying expenses.
- CRA *approximated* the existing rate base and remaining life for the relevant regions based on public utility data and rate data.
- New power plant additions add to the system rate base, with annual depreciation is dependent upon the book life of the technology type.
- Variable dispatch costs are a function of all the costs needed to produce electricity, while the fixed operating & maintenance costs reflect the costs needed to keep power plants functioning.
- If power is imported from outside, the cost is determined by the market price in that hour.
- These costs are divided by the Total Sales to determine the $/MWh cost of Generation.
- CRA assumes Transmission and Distribution costs grow in line with inflation at 2.1%.

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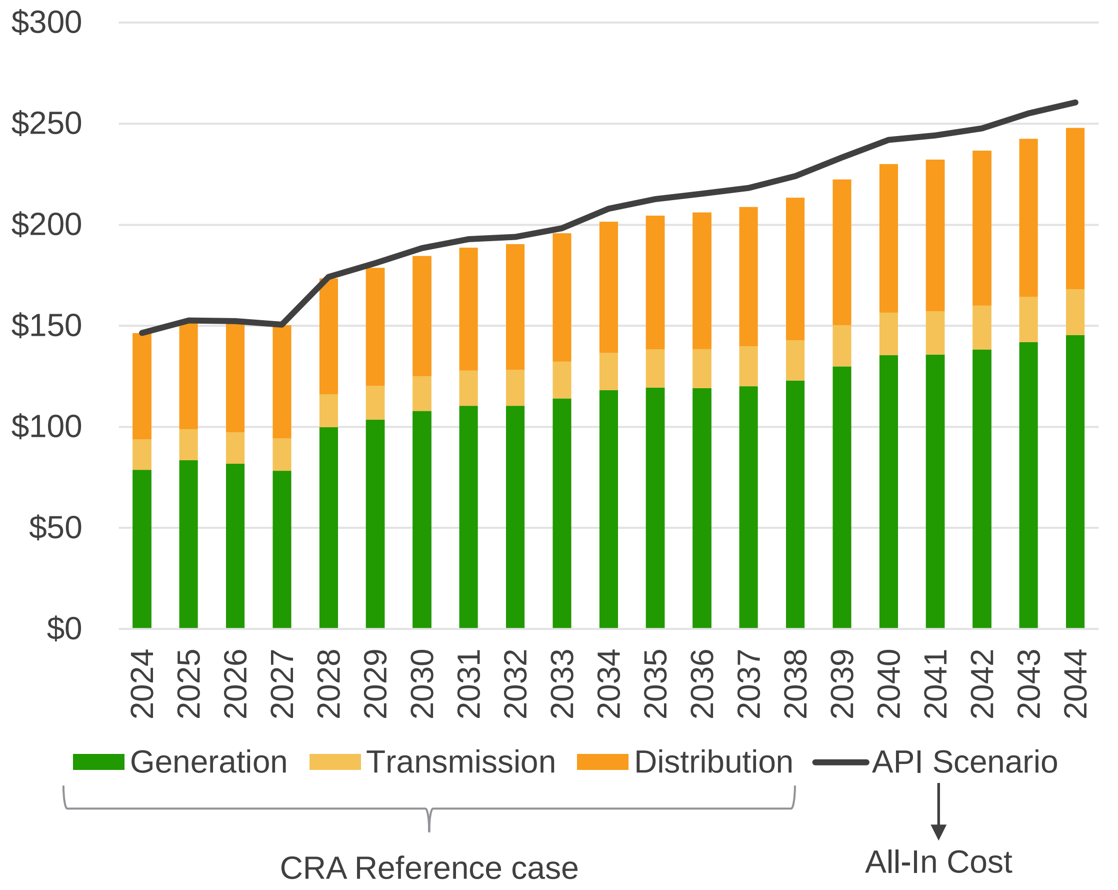
PJM DOMs growing electric demand results in high electric bills in both the CRA Reference case and API Scenario

PJM DOM Monthly Retail Rates ($/MWh)



Key Notes

- PJM Dominion has the largest demand growth in the CRA Reference case and API Scenario.
- Rising demand results in a continuous need for new generating capacity over the study period.
- By 2035 **generation costs** have risen to:
  - $119/MWh in the CRA Reference case, and
  - $128/MWh in the API Scenario.
- The higher costs in the API Scenario are driven by:
  - Higher fuel costs for natural gas plants,
  - Higher capital costs for new power plants, and
  - Higher import costs (both from the quantity purchased and the $/MWh price of imports).
- By 2044 the **total cost of service** has risen to:
  - $248/MWh in the CRA Reference case, and
  - $261/MWh in the API Scenario.
- The increasing spread in 2044 reflects an expansion and continuation of the trends seen in the 2030s.

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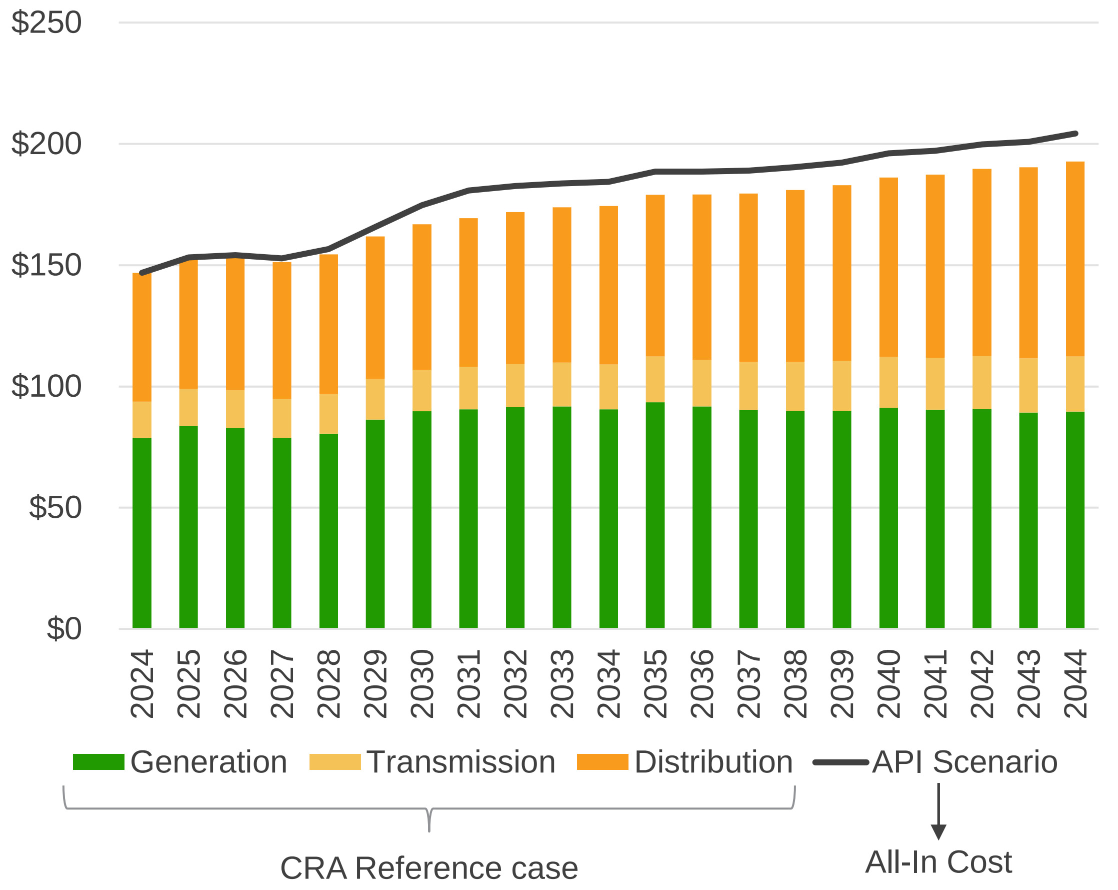
SERC SE's heavy reliance on gas causes higher electric bills for rate payers in API's Scenario

SERC SE Monthly Retail Electricity Cost Projections ($/MWh)

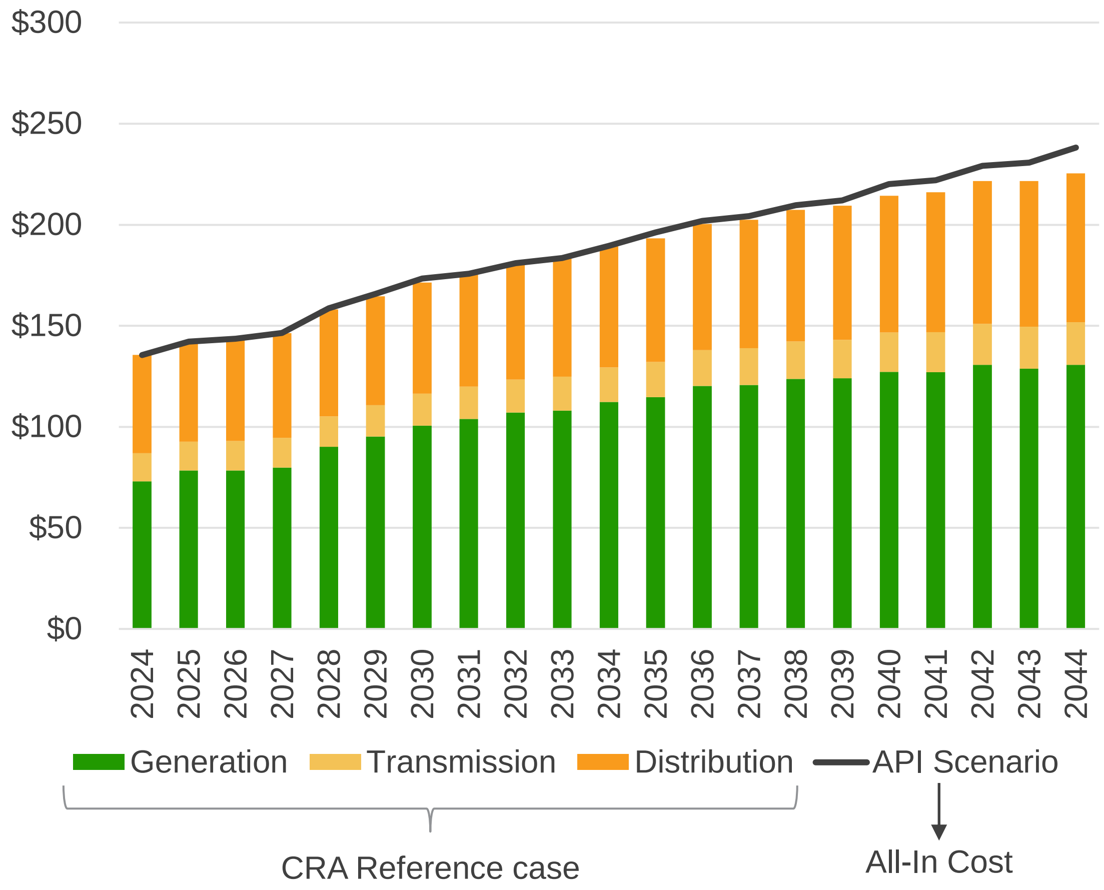


Key Notes

- SERC SE has very high demand growth in the first half of the study period.
  - During this time, generation costs rise as new capacity needs to be built quickly.
- In 2024 **generation costs** are $78.7/MWh, by 2035 they have risen to:
  - $93/MWh in the CRA Reference case, and
  - $103/MWh in the API Scenario.
- The higher costs in the API Scenario are driven by:
  - Higher fuel costs for natural gas plants,
  - A greater buildout of solar PV and storage capacity which has a higher construction costs compared to CRA Reference case.
- As electric demand flattens, the cost of generation begins to stabilize as resources are depreciated over time.
- By 2044 **generation costs** have fallen to:
  - $90/MWh in the CRA Reference case, and
  - $101/MWh in the API Scenario.

SERC VACAR does not see a substantial difference between the two cases until the later part of the study period

SERC VACAR Monthly Retail Rates ($/MWh)

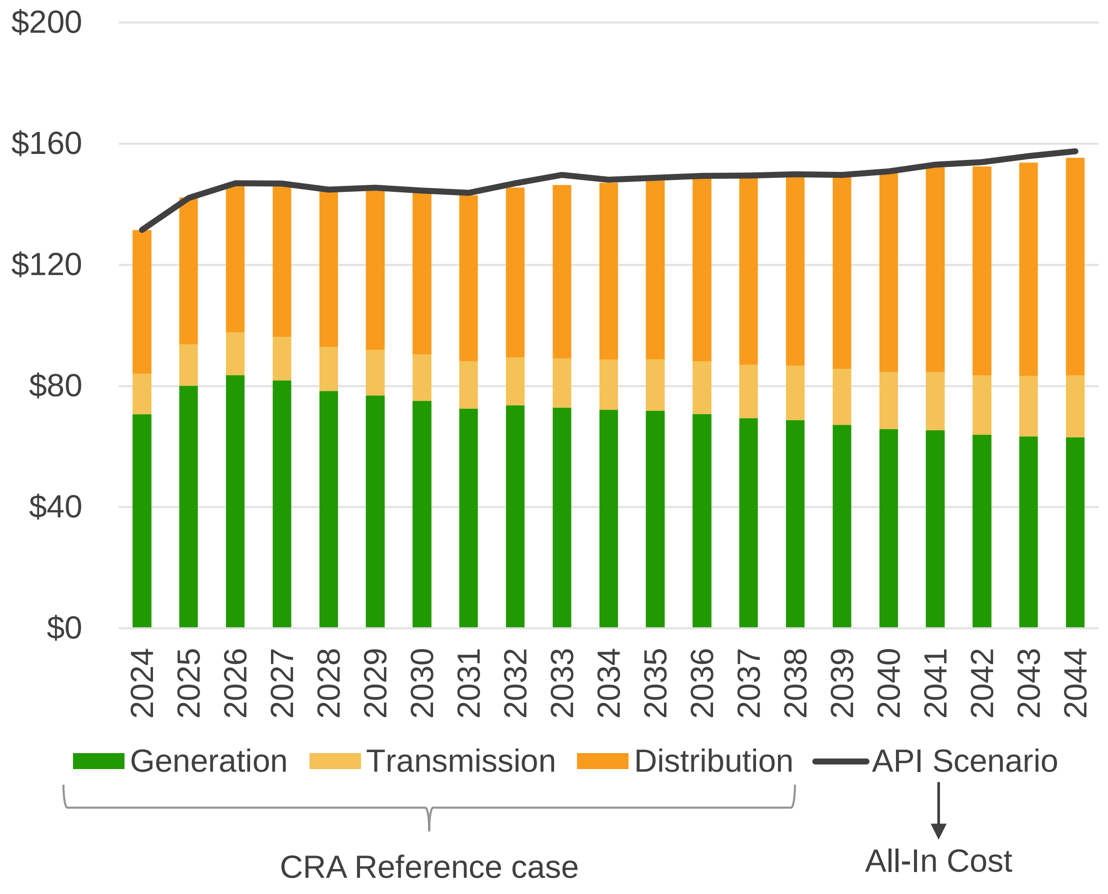


SERC VACAR Retail Rates ($/MWh)

- Like Dominion, VACAR has steadily rising demand over the study period, resulting in rising generation costs.
- By 2035 **generation costs** have risen to:
  - $115/MWh in the CRA Reference case, and
  - $118/MWh in the API Scenario.
- The lack of a difference between the CRA Reference case and API Scenario is driven by:
  - Natural gas only makes up 33% of generation (vs. 50% in SERC SE), and
  - Slightly more capacity is built in the CRA Reference case by 2035, resulting in higher capital costs feeding into the generation costs.
- By 2044 the **total cost of service** has risen to:
  - $225/MWh in the CRA Reference case, and
  - $238/MWh in the API Scenario.
- The increasing spread is driven by:
  - Higher fuel costs for natural gas plants,
  - Construction of more expensive nuclear SMRs in the 2040s, and
  - Higher import costs (both from the quantity purchased and the $/MWh price of imports).

The Total Cost of Service changes very little for TVA between cases due to its low demand growth and resource flexibility

SERC TVA Monthly Retail Rates ($/MWh)



Key Notes

- Unlike the other regions in the study, SERC TVA is not expecting large load growth,
  - The expected withdrawal of EPA GHG regulations means it does not anticipate electrification to push up demand.
- The only driver of cost differences is the variable costs of gas plants and the quantity of imports and exports.
  - In 2034, TVA only uses gas for 30% of generation and can reduce exports to reduce variable costs.
  - TVA builds the same quantity of capacity in both cases, though not always in the same year.
- In the final study years, the API scenario becomes slightly more expensive than the CRA Reference case due to:
  - Further rising variable costs for gas plants,
  - Higher import costs (both from the quantity purchased and the $/MWh price of imports).
- By 2044 the **total cost of service** has risen to:
  - $155/MWh in the CRA Reference case, and
  - $157/MWh in the API Scenario.

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About CRA – an overview of the firm

Charles River Associates (CRA) has for over 50 years been a leading global consulting firm offering investigative, economic, and strategic expertise to major law firms, corporations, financial institutions, and governments around the world.

In Energy, we help a wide range of clients across the sector assess investment strategies & opportunities, devise winning strategies, identify & access value pools, navigate & decode uncertainty, and transform operating models. We combine evidence-based research, rigorous analysis, regulatory & economic insight, together with proven industry experience to deliver value.

Increasingly, our analysis is **driven by the accelerating Energy Transition**, requiring clients to bring short- & medium-term objectives in sync with long-term implications and requirements.

Since its founding in 1965, CRA continues to distinguish itself in the professional services arena and is proud to have worked with **94% of the AmLaw 100** law firms and **83% of the Fortune 100** companies.

50+ Years advising clients

1,000+ Consultants (+ extended network of senior experts)

22 Offices in 10 countries

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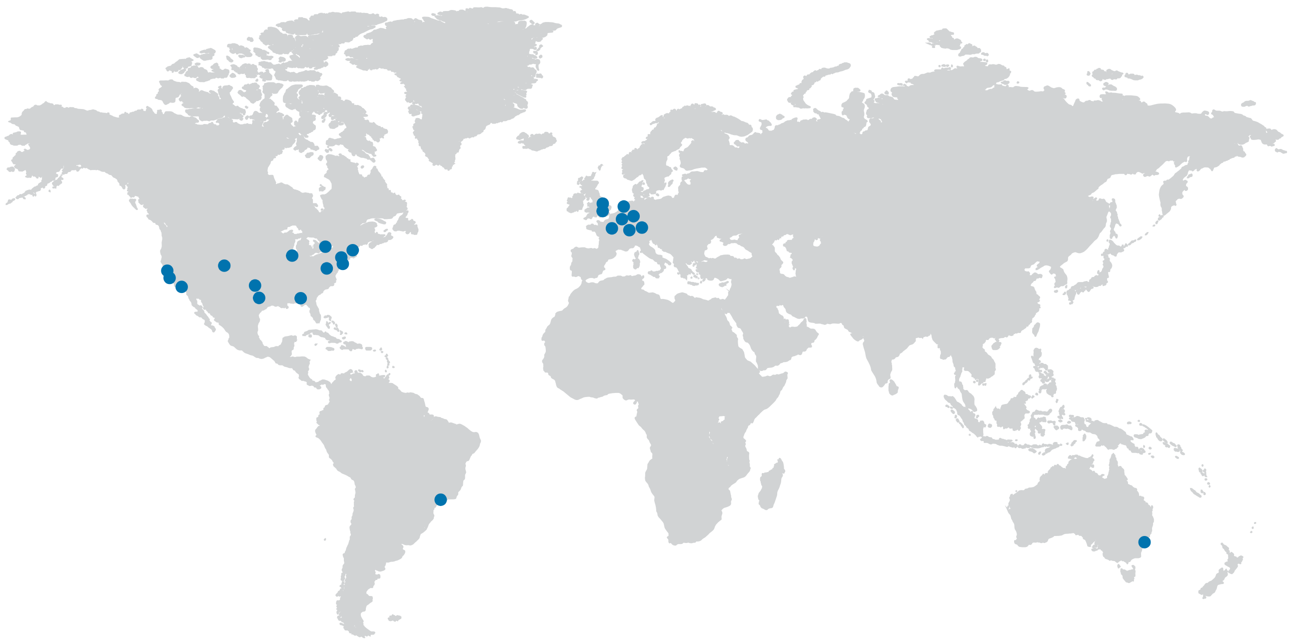
Charles River Associates is an established boutique consulting firm specializing in high stakes matters for clients across sectors

- **Founded in 1965**
- **1,000+ Consultants today**
- **23 Offices in 10 Countries**
- **Industry Practices**: Energy, Chemicals, Industrials, Metals + Mining, Life Sciences, Financial Services
- **Cross-Industry Practices**: Investigations, Strategy and Governance, Anti-trust

CRA Office Locations



Boston* - New York - Summit NJ - Washington DC - Tallahassee - Chicago - Dallas

Houston - College Station TX - Salt Lake City - Los Angeles - Oakland CA - San Francisco

Toronto - São Paulo - London - Cambridge - Paris - Brussels - Amsterdam - Zurich

Düsseldorf - Munich - Sydney

Key Industry Verticals We Serve

Power

- Infra owners, Investors, Utilities, ISOs
- Wholesale Market Design, Market Price Forecasting, Plant Economics, Portfolio Analysis, Transmission Studies

Chemicals + Industrials

- Petrochemicals, polymers, specialty chemicals, inorganics, ag chemicals
- Business strategy, Performance Improvement, Growth Strategy, Portfolio Strategy, M&A Diligence, Capital Allocation.

Utilities

- Electric, Gas, Water Utilities
- Strategy, Resource Planning, Regulatory and Policy Support, Procurement

Metals + Mining

- Basic minerals, Iron and steel, aluminum, composites & specialty metals
- Investment analysis, Portfolio strategy, Market assessment M&A diligence, technology plans

Midstream

- NG Pipeline, Hydrogen
- Strategy, Comparative Economics, Regulatory and Policy Support

CleanTech

- Advanced generation technologies, E-mobility, DER integration companies
- Strategy, Market Entry, Competitive Evaluation

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CRA's primary fundamental market modeling tools are Aurora, which models the power sector, and NGF which models the natural gas sector

Natural Gas Fundamentals Model

CRA FORECASTS NATURAL GAS PRICES BASED ON EXPECTATIONS AROUND SUPPLY AND DEMAND

A fundamental price forecast answers the question: "What gas price is needed to satisfy total demand and make producers whole?"

CRA Natural Gas Fundamentals Model (NGF)

Gas Supply

- Total resource in place, proved and unproven
- Resource growth over time
- Wet / dry product distribution
- Historic wells drilled and ongoing production
- Conventional & associated production
- Existing tight & coal bed methane
- Existing offshore production

Well Performance

- Drilling & completion costs
- Environmental compliance costs
- Royalties & taxes
- Initial production rates
- Changing drilling and production efficiencies over time
- Productivity decline curve
- Well lifetime
- Distribution of performance

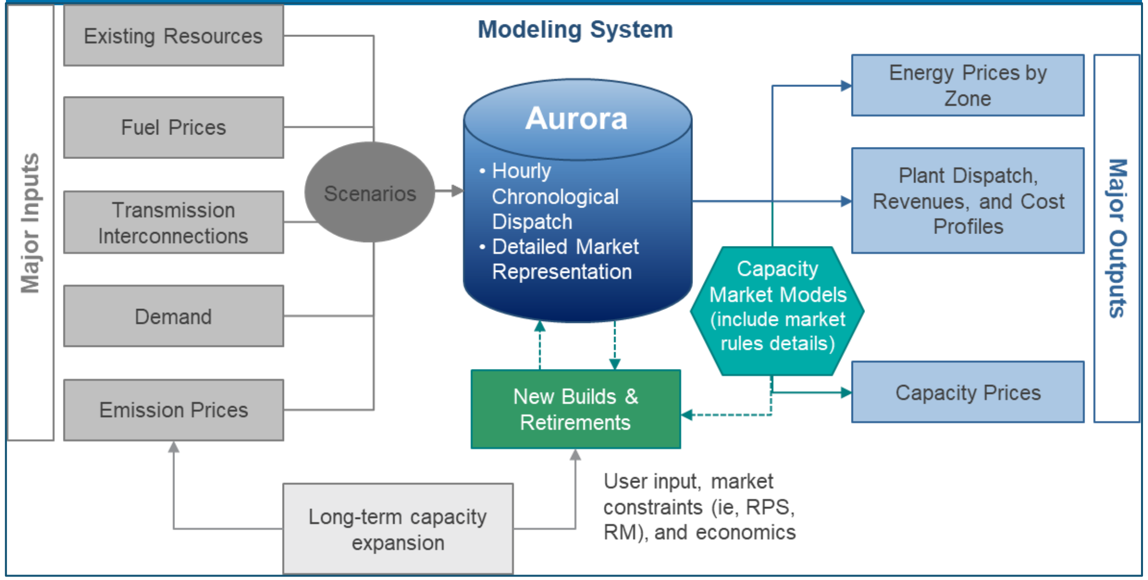
Gas Demand

- Electric and non-electric sector demand forecast (domestic)
- International demand (net pipeline & LNG exports)

Other Market Drivers

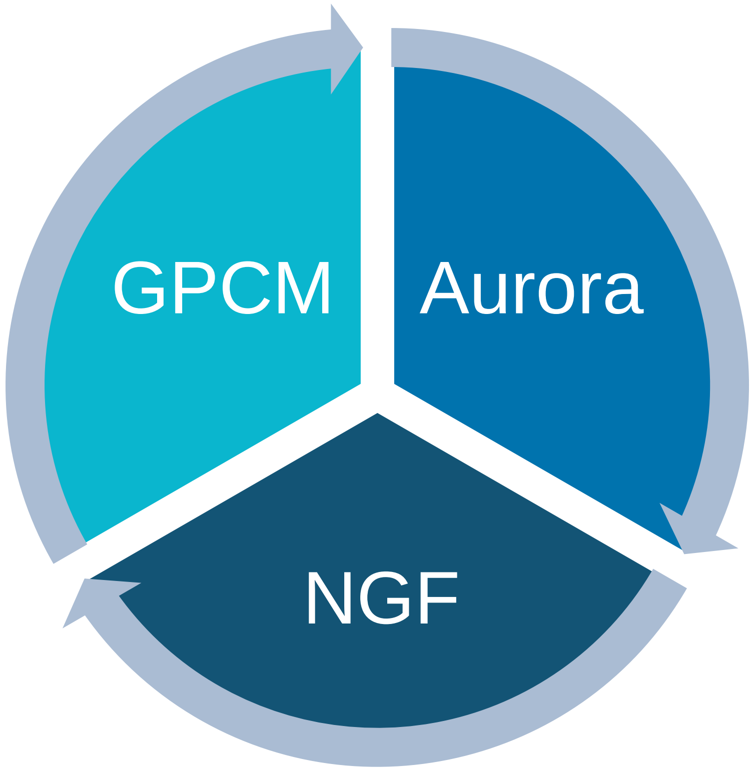
- Value of natural gas liquids and condensates
- Natural gas storage

Aurora XMP



CRA engaged in an iterative process between its electric and natural gas models, which also includes GPCM for gas basis

CRA's Iterative Process



Key Notes

- The **Gas Pipeline Competition Model (GPCM)** is a network flow model of the North American natural gas market, which incorporates detailed representations of supply, demand, and pipeline infrastructure.
  - GPCM is used to assess the impact of the Reference case and scenario on Southeast gas prices.
- CRA's **Natural Gas Fundamentals (NGF)** model provides a bottom-up forecast of North American gas production with a focus on producing a price outlook for Henry Hub.
  - Production cost inputs are aligned with GPCM to produce a consistent outlook.
- **Aurora** is a chronological, hourly dispatch model that represents all major electric pricing zones across North America. It is run in hourly, chronological format and produces energy prices for each zone, along with plant-level dispatch.
  - Aurora power sector gas demand is iterated with gas prices provided by GPCM and NGF until all are in alignment.

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Rates of Growth in Retail Customer Bills

Overview of CRA approach to forecasting customer rate impact

Δ% Retail Bills ~ **Δ% Total Cost of Service** = ∑ **Generation**, **Transmission**, **Distribution**

By scenario

Transmission and Distribution: Less impacted by key study variables, potential for minor variation across scenarios.

Generation:

Fixed Costs

- Existing resource base (existing book value)
- Levelized capital cost of new capacity additions, including return on investment
- Operating unit FOM

Variable Costs

- Total system costs (as opposed to marginal cost setting a wholesale price)
  - Fuel
  - VOM
  - Emissions

Upon determining current costs of T&D, CRA assessed the changes in generation costs (assuming T&D grow at the assumed rate of inflation) and thereby approximate the change in retail bills over the study period. CRA assessed starting points based upon the major utilities in each of the states.

Initial Financial Assumptions

Starting Rate Base	• The Base Rate is assumed to represent the current generation costs based upon the Edison Electric Institute's (EEI) Typical Bills and Rates reports for Summer 2023 and Winter 2024.
Average Gen Asset Life Remaining	• Average number of years remaining in the fleets assets based on their air, average book life and weighted by capacity.
Return on Equity (ROE)	• Assumption based on utility's latest rate case or other public information
Cost of Debt	•Cost of debt procured by the utility
Federal Tax Rate	• Federal tax rate is assumed to remain constant over the study period • TVA doesn't pay federal taxes and is exempt
State Tax Rate	• State tax rate varies by state, but is assumed to remain constant over the study period. • TVA makes a payment in lieu of taxes which is assumed to average 6.5% over the study period.
Equity %	• Assumption based on utilities latest rate case • For TVA data was determined with research from Capital IQ
Debt %	• Assumption based on utilities latest rate case • For TVA data was determined with research from Capital IQ

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Power Plant Assumptions

- Historic Fixed Operation & Maintenance Costs ($/kW)
  - Taken from utility FERC filings and EIA Capital Cost and Performance Characteristics for Utility-Scale Electric Power Generating Technologies: 2024 Edition
- Installed Capacity (System-Wide MW)
- New build Capital Costs ($/kW) - all-in includes Transmission Interconnection, net of Investment Tax Credits
- Build Schedule
- Total dispatch costs ($/MWh)
  - Fuel,
  - Emissions, and
  - Variable Operating & Maintenance Costs
- Total Generation (MWh)

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