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Reliable Affordable Infrastructure
for Secure Energy

JANUARY 2026

APPENDICES

Utilizing East Coast Natural Gas Infrastructure

System-Level Pathways for Emerging Fuels,
Infrastructure Modernization, and Regional Flexibility

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Appendix A: Emerging Fuel Pathways Considered

Hydrogen

Hydrogen (H_2) is typically produced via steam methane reforming (SMR) of natural gas for approximately $1/kg (Lewis et al., 2022). As a carbon-free energy carrier, H_2 can help decarbonize heavy industries, long-distance transport, and energy storage. However, for a low-carbon future, its production must minimize carbon emissions. In this case study, Case H2-1 represents H_2 production via SMR of natural gas incorporating carbon capture and storage (CCS) with an overall capture rate of at least 96% (Lewis et al., 2022). This pathway is similar to conventional H_2 production but with the addition of solvent-based CO_2 capture systems for capturing from both the syngas and the flue gas streams and with a CO_2 compression train.

Case H2-2 is production via autothermal reforming (ATR) of natural gas with CO_2 capture from syngas at an overall capture rate of at least 94%, as defined by the chosen literature source (Lewis, et al., 2022). Note that the capture rates presented are a function of the selected process design and nominal capture rates of individual CO_2 capture units, which were obtained from CO_2 capture technology developers. The Lewis, et al. (2022) SMR case utilizes both CO_2 capture from syngas at 95% and flue gas at 90%, resulting in high overall capture rates for SMR, as a goal of the study was to evaluate configurations with high capture rates. If CO_2 is only captured from syngas, for example, the SMR capture rate would be about 62% (Lewis, et al., 2022). The ATR design only includes CO_2 capture from syngas at a nominal rate of 95 percent, as the flue gas stream is relatively small and contains a small concentration of CO_2, so additional capture is not economic. However, if the syngas capture unit rate is increased from 95% to 99%, overall ATR capture rates would increase to 98%. Lummus Technology (2025) describes various SMR and ATR configurations and their CO_2 removal rates, which aligns with the configurations and capture rates seen in Lewis, et al. (2022). Costs are reflective of the selected process designs from Lewis, et al. (2022).

Case H2-3 represents SMR of RNG upgraded from landfill gas (LFG) sourced from the region, without CCS. Case H2-4 represents ATR of RNG without CCS. Case H2-5 represents SMR of RNG with CCS, with a configuration similar to case H2-1 in implementing a capture rate of over 96% (Lewis, et al., 2022). Case H2-6 represents ATR of RNG with CCS, with a configuration similar to case H2-2 in implementing a capture rate of over 94% (Lewis, et al., 2022).

Case H2-7 represents H_2 production via plasma pyrolysis of natural gas, in which a plasma torch is used to decompose methane (CH_4) into gaseous H_2 and solid carbon, which avoids significant direct CO_2 emissions. A benefit of this technology is the production of solid carbon, which can be sold to provide revenue to the plant and reduce the cost of H_2.

Case H2-8 represents H_2 production via proton exchange membrane (PEM) electrolysis in which electricity is used to split water to form hydrogen and oxygen byproducts, avoiding any direct CO_2 emissions. Since this pathway uses a significant amount of electricity, it is important that the electricity is sourced from low-carbon resources. Case H2-8 has been expanded to six sub-cases to evaluate production using six different low-carbon electricity sources: H2-8a uses electricity sourced from photovoltaic (PV) solar; H2-8b, onshore wind; H2-8c, nuclear power; H2-8d, hydropower; H2-8e, biomass without CCS; and case H2-8a/b combines solar and wind with battery storage to improve capacity factors (CFs) (EIA, 2022b).

Renewable Natural Gas

The RNG cases involve thermal or biological conversion of natural or waste resources into a natural gas alternative. A benefit of RNG over low-carbon H_2 is that it can be directly substituted for natural gas without any retrofitting or replacement of end-use technologies (EERE, n.d.); however, it will still create CO_2 emissions when combusted.

Case RNG-1 represents utilizing gasification technology to convert municipal solid waste (MSW) diverted from landfills into syngas, a mixture of carbon monoxide (CO) and H_2, which can then be upgraded to RNG via the methanation process.

Case RNG-2 represents RNG production from woody biomass (e.g., organic material derived from trees, shrubs, vines, leaves, etc.) via gasification and methanation processes. Case RNG-3 represents RNG production by upgrading LFG produced through anaerobic digestion of MSW from landfills.

Synthetic Natural Gas

SNG is produced by converting CO_2 and H_2 into a natural gas alternative. This study only considers electrolysis-to-methanation pathways using CO_2 from industrial or power plants that sell captured CO_2 to offset capture costs, avoiding the need for CO_2 transport and storage. H_2 is produced via PEM electrolysis with low-carbon electricity, following the same specifications as case H2-8. Unlike low-carbon H_2, SNG can replace natural gas without retrofitting but still emits CO_2 when combusted (EERE, n.d.). SNG-1 represents utilizing CO_2 captured from the flue gas of a natural gas combined cycle (NGCC) power plant using a solvent-based capture system. For SNG-2, the CO_2 is captured from a cement plant, specifically from the kiln off-gas. SNG-3 sources CO_2 from a steel plant, including the power plant stack, coke oven gas, and the blast furnace stove. SNG-4 uses the high-purity CO_2 byproduct from fermentation at an ethanol plant, requiring only compression. Note that the availability of the CO_2 feedstock and, therefore, the ability to produce SNG, depends on the existence of the CO_2 point source facility type within the region. Affordable access to CO_2 and H_2 must be considered when producing SNG from these feedstocks. Since multiple cost scenarios exist for H2-8 based on the low-carbon electricity source, the two lowest-cost scenarios are assumed to supply H_2. Consequently, SNG cases include letters that denote the source of electricity used to produce electrolytic H_2 (e.g., “SNG-2c” signifies that the electrolytic H_2 is produced via nuclear power).

Appendix B: Case Study Approach

Optimization Model

Hydrogen Market Module Description

The Hydrogen Market Module (HMM) is a key supply module included in OL-NEMS to represent H_2 as a feedstock and energy carrier. HMM enables understanding of the development of H_2 under different technology, policy, and market scenarios.

Technology Updates for H2

For the low-carbon H_2 production technologies considered in this case study, OL-NEMS includes updated technology costs. For production technologies not currently represented (e.g., NG SMR without CCS), existing data was added to provide a full suite of options for the BAU scenarios.

Within the HMM, these values represent the initial costs for the conventional representation of these technologies. Learning is endogenous in the HMM, and specific to each technology. For each doubling of capacity, capital costs are set to decline by 3%. Therefore, cost reductions are scenario specific. Not all inputs for these technologies need to be updated as some are endogenously calculated within the HMM (e.g., fuel prices, electricity prices, CO_2 emissions, and CO_2 T&S costs).

OL-NEMS Regional Inputs

These adjustments include fuel or feedstock cost, electricity cost, and CO_2 transportation and storage (T&S) costs. Since this regional study primarily impacts the HMM, Natural Gas Market Module (NGMM) (EIA, 2022c), Electricity Market Module (EMM) (EIA, 2022a), and Oil & Gas Supply Module (OGSM) (EIA, 2020) in OL-NEMS, the following discussion describes the regionality of the various data flows between them.

Regional Updates for H2

The HMM uses census regions for fuel and electricity demand and H_2 supply. As seen in **Figure 1**, the East Coast regionality specified includes census regions 1, 2, and 5. To determine the fuel and electricity demand for the East Coast region, the H_2 demand was restricted to the sum of demand in regions 1, 2, and 5.

For the inputs into the HMM, natural gas and electricity prices are available at the census region level but do not change between states. Therefore, they will be used for this East Coast region unchanged. Natural gas and electricity supply can be limited to regions 1, 2, and 5. However, for the BAU scenarios, initial testing shows that the supply constraints for natural gas and electricity will not be reached; thereby, the supply is not restricted.

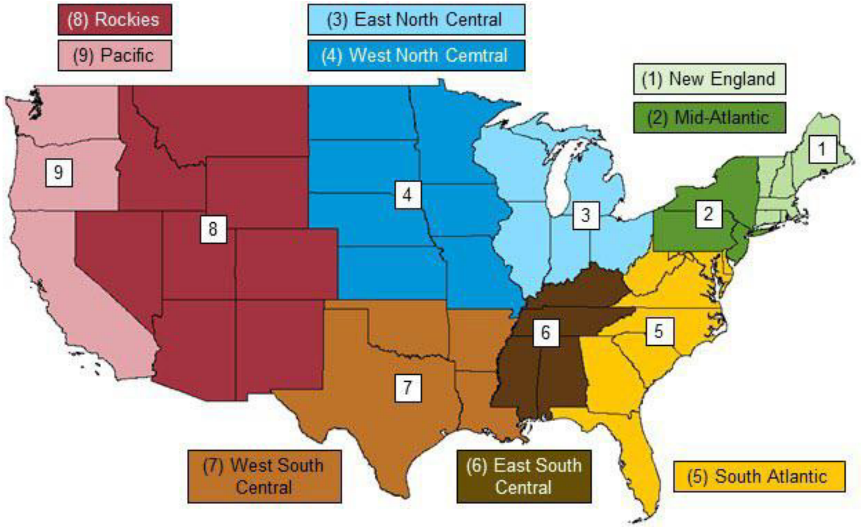

Figure 1. U.S. census regions, numbered (source: EIA)

Regional Reporting for Natural Gas

Onshore NG production is reported by the OGSM at the OGSM region level as seen in **Figure 2**. The OGSM also reports OGSM district-level natural gas production, which can be used to calculate overall production for the states in the East Coast region.

Figure 2. Oil and gas supply regions (source: EIA)

Natural gas prices are reported both at the census and OGSM region level and can be processed to produce a weighted average price for the specified East Coast region. The NGMM reports natural gas pipeline capacities and flows between regions using natural gas regions as shown in **Figure 3**. The New England, Southeast, and Florida regions are all completely within the East Coast region and their capacity are reported directly. All the states except Ohio in the Mid-

Atlantic & Ohio region are included, therefore this region's capacity are reported as a proportion benched to current capacity in that region.

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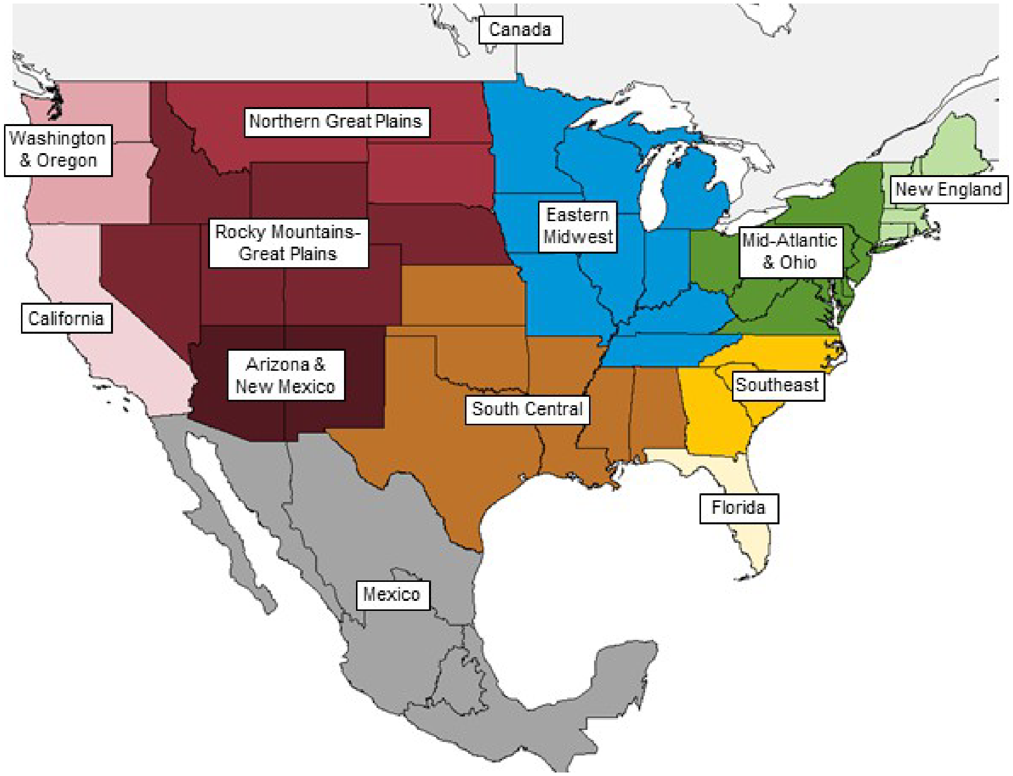

Figure 3. Natural gas regions (source: EIA)

Regional Reporting for Power

OnLocation reports power generation using different technologies including NGCC plants. The EMM uses North American Electric Reliability (NERC) regions (**Figure 4**) for reporting that do not neatly conform to state boundaries. However, which region each state is roughly falling in for most of its generation can be identified. All the states in regions 2, 7, 8, 9, 10, 13, and 14 are part of the East Coast directly, while only part of region 11 (West Virginia and parts of Pennsylvania, Maryland, and Virginia) and 15 (Georgia) are in the East Coast region. For region 11 and 15, OnLocation uses its share of total generation for reporting (~10% and ~50%, respectively, in 2023). These historical shares are available from EIA (2024d).

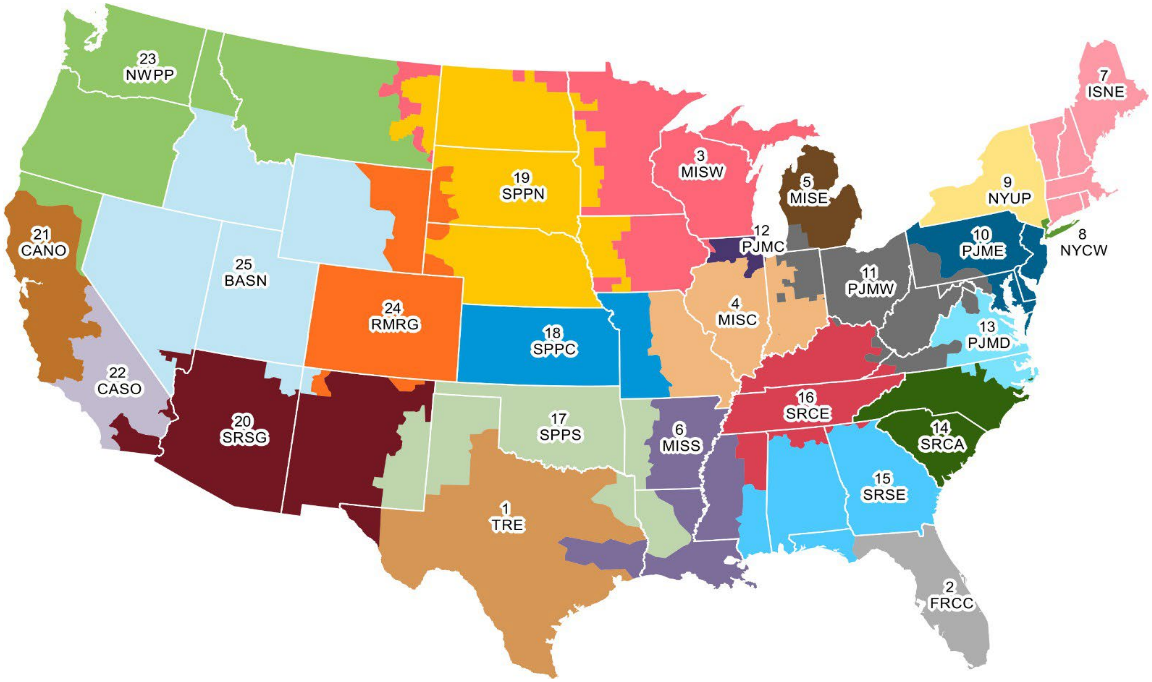

Figure 4. Electricity supply regions (used with permission from NERC)

CO_2 Transport & Storage Cost

The cost of CO_2 T&S was adapted from the NETL CO_2 Capture, Transport and Storage (CTS) Cost Screening Tool (Warner, et al., 2024). The screening tool identifies the top ten optimal T&S cost scenarios, identified by storage site location, for a particular CO_2 source. For transport cost, the tool determines the pipeline transport cost for a greenfield pipeline based on user inputs. Then the tool determines storage costs for all storage options, assuming greenfield storage projects based on user inputs. Finally, the tool sums the transport and storage costs and reports the lowest cost options. For each state in the region, a major city was selected as the source location of the CO_2, and the tool suggested the most optimal T&S cost scenario. The T&S cost assumes dedicated pipeline and dedicated saline storage with no 45Q incentives assumed and 10% route tortuosity (Warner, et al., 2024). The construction period for the pipeline is 5 years, and the duration of operation is 30 years (Warner, et al., 2024). However, a limitation of the tool is that the CO_2 mass flow rate able to be selected is based on large-scale commercial projects, some of which are much larger than the cases in this study with CCS. Therefore, a simplification was made that assumed a moderate CO_2 mass flow rate of 1 million tonnes per year, consistent with the amount captured from a cement plant (Warner, et al., 2024), for all T&S calculations. This aligns with a future energy scenario in which CO_2 capture, transport, and storage is commonplace, and CO_2 pipelines are not just designed for use by individual plants. The CO_2 T&S price, pipeline distance, and storage formation is shown at the state level in **Table 1**.

Table 1. State-level CO_2 T&S costs for the East Coast region

East Coast			
State	**CO_2 T&S Cost (2023$/tonne)**	**Pipeline Distance (mi)**	**Storage Formation**
Connecticut	28.86	320	Waste Gate 1
Delaware	19.51	70	Waste Gate 1
Florida	24.75	40	Lower Tuscaloosa 5

Georgia	26.51	210	Lower Tuscaloosa 5
Maine	44.47	570	Waste Gate 1
Maryland	18.53	80	Waste Gate 1
Massachusetts	38.38	400	Waste Gate 1
New Hampshire	39.32	440	Waste Gate 1
New Jersey	25.00	160	Waste Gate 1
New York	25.93	350	Waste Gate 1
North Carolina	37.44	260	Waste Gate 1
Pennsylvania	21.52	170	Waste Gate 1
Rhode Island	35.09	360	Waste Gate 1
South Carolina	34.45	320	Lower Tuscaloosa 5
Vermont	43.07	490	Waste Gate 1
Virginia	20.02	130	Waste Gate 1
West Virginia	29.14	180	Mount Simon 10

Utilizing East Coast Natural Gas Infrastructure for Emerging Fuels – Appendix

Business-as-Usual (BAU) Scenarios

2023 Annual Energy Outlook Reference Case

In EIA's AEO23 Reference case (referred to as AEO23 in the modeling results in Appendix H), an assessment of how U.S. and world energy markets would operate through 2050 is made under current laws and regulations as of November 2022 under evolutionary technological growth assumptions. The key assumptions in this case provide a baseline, or experimental control, for exploring long-term trends.

OL-NEMS 2024 Reference Case

While AEO23 and OL-NEMS have many underlying assumptions in common, there are some key differences:

OL-NEMS includes updated policies and regulations that have been passed since AEO23 was published, including new Environmental Protection Agency (EPA) GHG standards for both power plants and vehicles, select appliance standards, and state-level policies, including zero-emission vehicles and mandates for battery storage and offshore wind.

OL-NEMS provides a more complete representation of the IRA provisions, including tax credits for clean fuels, H_2, and direct air capture, and implements additional Bipartisan Infrastructure Law (BIL) provisions, including funding for advanced nuclear and CO_2 capture demonstration plants and CO_2 pipeline and storage subsidies.

OL-NEMS assumes lower costs for renewable and carbon capture technologies, and for electric vehicles, and greater data center electricity demand growth in the commercial sector, along with many other policy and data updates.

OL-NEMS assumes a combination of updated policies and regulations and lower technology costs, resulting in a more rapid phase-out of conventional fossil fuels in favor of renewables, including solar, wind, and biofuels, and electric vehicles.

OL-NEMS assumes total primary consumption is higher primarily due to higher growth in electricity sales, driven primarily by additional data centers.

Note that this case is referred to as Reference in the results shown in Appendix H.

Low Oil & Gas Supply

Compared to the OL-NEMS 2024 Reference, the Low Oil & Gas Supply (Low OGS) scenario assumes that 1) the estimated ultimate recovery per well for tight oil, tight gas, or shale gas in the United States; 2) the undiscovered resources in Alaska and the offshore Lower 48 states; and 3) rates of technological improvement, are all 50% lower.

This scenario assumes support for the market adoption of emerging fuels, based on the expectation that their competitiveness with oil and gas will improve as delivery infrastructure becomes more available.

High Economic Growth, High Zero-Carbon Technology Cost

This scenario explores the adoption of emerging fuels in a high economic growth market where zero-carbon technology costs remain high. It assumes the compound annual growth rate for U.S. gross domestic product (GDP) is 2.3%. By contrast, the AEO23 Reference and OL-NEMS 2024 Reference cases assume the U.S. GDP annual growth rate is 1.9%.

This scenario also considers the sensitivities around capital costs for electricity-generating technologies that produce zero emissions, which include renewables, nuclear, and diurnal storage technologies. The capital costs are assumed to decline over time from learning by doing as commercialization expands and construction and manufacturing experience accelerates.

Emerging Fuel Pathway Evaluation Inputs and Assumptions

LCA and TEA are baseline analyses of individual technologies within each fuel pathway that help establish technology priorities. Firstly, LCA uses upstream emissions intensity of feedstocks for each technology (natural gas consumption, electricity consumption) to determine GHG intensity (a.k.a. carbon intensity, CI). Similarly, TEA analyses calculate a levelized cost of production of decarbonized fuel based on individual cost components, including any available credits that can depend on technology CI. Variables for these LCA and TEA calculations can depend on subregion within the East Coast.

The OL-NEMS model uses subregion LCA and TEA results, as well as specifications from the BAU and emerging fuel pathway scenarios. Variables include technologies employed, available policies/credits, consumer behavior, and international interactions. The goal for this model is to calculate long-term energy projections (supply, demand, and price). Compared to the LCA and TEA calculations, this model determines a time series of data to project the effect of fuel use choices.

The CBA relates the OL-NEMS results to real-world decisions. It calculates breakeven CO_2 emissions prices, above which the use of a particular pathway can help to provide consumers with cost-effective fuels that lead to a lower carbon footprint. These breakeven CO_2 emissions prices are provided for each technology within all pathways. The lower breakeven prices identify pathways and technologies with the greatest potential for success.

Appendix C: Techno-Economic Analysis

Methodology

This section details performance and cost assumptions used to develop all TEA study cases, and methods to ensure consistent assumptions, particularly associated with costs, across all cases to facilitate comparison.

Levelized Cost Metric

The key economic metric for this study is the levelized cost; the revenue required per unit of product produced during the plant's operational life to meet all capital and operational costs (Theis, 2019). For low-carbon H_2 cases, this is the levelized cost of H_2 (LCOH), in units of \$/kg H_2. For SNG and RNG cases, the metric is the levelized cost of natural gas (LCONG), in units of \$/MMBtu on a higher heating value basis.

The NETL Cost Estimation Methodology QGESS (Theis, 2019) was used to determine the levelized cost. The levelized cost of a product, whether LCOH or LCONG, is the sum of the levelized capital cost (LCC), variable operation and maintenance (O&M) cost (VOMC), fixed O&M cost (FOMC), and fuel or feedstock cost (FC).

$$\mathrm{LCOH\ or\ LCONG} = \mathrm{LCC} + \mathrm{VOMC} + \mathrm{FOMC} + \mathrm{FC}$$

The cost metric is reported on a normalized basis, by the annual production rate of the product (i.e., H_2, SNG, or RNG), considering the annual capacity factor (CF) of the plant. The annual production rate is based on the selected plant capacity, which is reported on an hourly rate. The plant capacity and CF of each case is discussed in the following subsections. This report assumes CF and availability are equal for each facility, given that each new plant would be dispatched any time it is available and would be capable of generating the nameplate capacity when online. Additionally, the calculations assume that the CF and availability are constant over the life of the plant, but in practice, a plant will have a higher peak availability to counter lower availability in the first several years of operation" (Lewis, et al., 2022). Thus, the annual production rates are calculated as a function of the referenced CFs and plant capacities. The formula below shows the annual production rate of the plant, based on the desired units and inclusion of CF.

$$\begin{aligned}\text{Annual Production Rate (@CF)} &= \text{Annual Production Rate (100\% CF)} * \text{CF(\%)} \\ &= \text{Plant Capacity}\left(\frac{\text{kg}}{\text{day}}\right) * 24\frac{\text{hr}}{\text{day}} * 365\frac{\text{day}}{\text{year}} * \text{CF(\%)}\end{aligned}$$

Capital Costs

The levels of capital cost estimated are summarized in **Figure 5.**

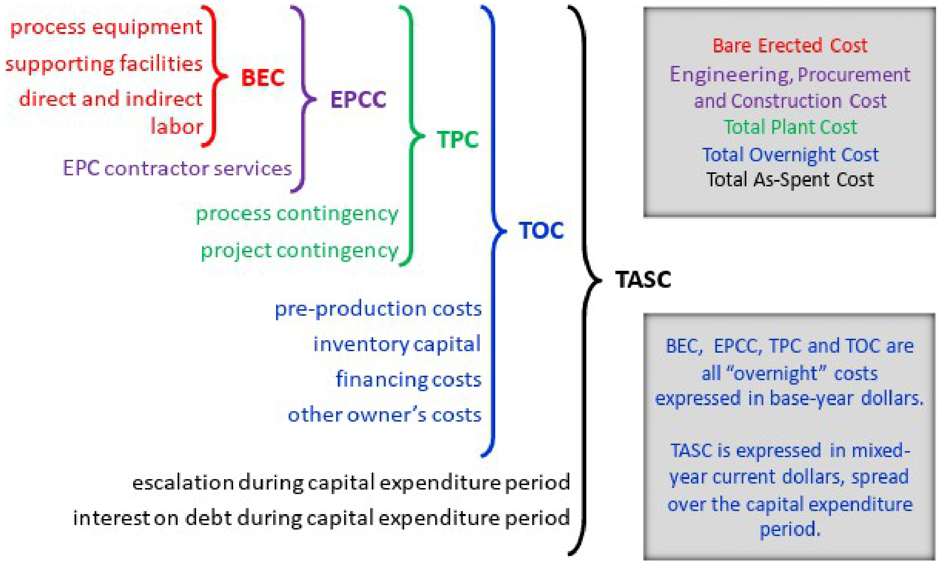

Figure 5. Capital cost levels and their elements [source: NETL (Theis, 2019)]

A portion of the bare erected cost includes direct and indirect labor costs, which are varied by region based on labor rates. Costs were scaled from reference studies based on the following scaling law with an exponent of 0.6 following the "rule of 6/10th" (Whitesides, 2020) and the ratio of production capacities.

$$Capital\ Cost = Reference\ Cost * \left(\frac{Plant\ Capacity}{Reference\ Capacity}\right)^{0.6}$$

Furthermore, all costs were scaled from their original cost year to the year 2023 via the Chemical Engineering Plant Cost Index (CEPCI).

$$Capital\ Cost_{2023} = Capital\ Cost_{Reference\ Year} * \left(\frac{CEPCI_{2023}}{CEPCI_{Reference\ Year}}\right)$$

Capital costs are levelized over the 30-year plant operating period by applying an industry-specific fixed charge rate (FCR) to the total as-spent cost (TASC). The FCR is a function of debt/equity ratio, interest rate, return on equity, inflation, depreciation, and other financial factors. Estimating the FCR requires multiple assumptions and steps and has not been reproduced here, but the procedure is described in the NETL Cost Estimation Methodology QGESS (Theis, 2019). The FCR determined for this study is 0.0689 based on financial data for the H_2 industry. The capital cost is then normalized by the annual production rate of the product (i.e., H_2, SNG, or RNG), at CF, to determine the LCC.

$$\mathrm{LCC} = \frac{\mathrm{TASC} * \mathrm{FCR}}{\mathrm{Annual\ Production\ Rate\ (100\%\ CF)} * \mathrm{CF}}$$

Operating Costs

FOMCs are costs that are not proportional to the operating capacity of the plant and include costs for labor, property taxes, and insurance. Labor costs are region-specific. The FOMC is determined by normalizing the cost by the annual production rate.

$$\mathrm{FOMC} = \frac{\mathrm{Fixed\ O\&M\ Costs}}{\mathrm{Annual\ Production\ Rate\ (100\%\ CF)} * \mathrm{CF}}$$

The VOMCs are proportional to the operating capacity of the plant and include electricity costs, consumable costs, waste disposal costs, maintenance material costs, coproduct sales, and CO_2 T&S. The coproduct sales considered include carbon black from the plasma pyrolysis case (H2-7) and electricity exported to the grid in the gasification to RNG cases (RNG-1 to RNG-3). Region-specific costs include electricity costs and CO_2 T&S costs.

$$\text{VOMC} = \frac{\text{Variable O\&M Costs (100\% CF)} * \text{CF}}{\text{Annual Production Rate (100\% CF)} * \text{CF}}$$

Feedstocks used in the study include natural gas or RNG for the low-carbon H_2 cases, H_2 and CO_2 for the SNG cases, and MSW or biomass for the RNG cases. The natural gas, H_2 feedstock, and CO_2 feedstock costs are region-specific and the regional availability of RNG, CO_2, MSW, and biomass feedstocks impact plant capacity. The VOMC and FC are determined by multiplying the flow rate by the cost and normalizing by the production rate.

$$\text{FC} = \frac{\text{Annual Fuel Consumption Rate (100\% CF)} * \text{CF} * \text{Fuel Price}}{\text{Annual Production Rate (100\% CF)} * \text{CF}}$$

Assumptions

The National Energy Technology Laboratory's (NETL) Quality Guidelines for Energy System Studies (QGESS) provided the basis for the cost estimation methodology and has been consistently utilized throughout various referenced NETL studies.

The electricity costs reported are considered to be estimated unweighted levelized costs of electricity (LCOEs) for new resources entering service in 2027 (EIA, 2022b), and more assumptions for the LCOE calculation can be found in the AEO Levelized Costs report (EIA, 2022b).

Appendix D: Lifecycle Analysis

Methodology

The following sections discuss how the various models used have been created originally and modified as needed for use in this project.

Life Cycle Framework of the OHI Toolkit

The OHI toolkit, a joint effort of GTI Energy, NETL, and S&P Global, was released in 2024 and can estimate the GHG intensity of producing H_2 from 13 different technology pathways and in nearly any part of the world. The OHI toolkit is a life cycle-based model and represents cradle-to-gate emissions of producing 1 kg of H_2 in all pathways. Results are aggregated consistently into categories of H_2 Production, Upstream Electricity, Upstream Natural Gas, Upstream Biomass, Upstream RNG, Upstream LNG, Carbon Management, and Co-Product Management. Some pathways do not have any emissions associated with these categories (e.g., if RNG or liquified natural gas [LNG] is not used, or if there are no co-products). Energy is modeled on a lower heating value basis, and GHG emissions are first estimated on a speciated basis (i.e., of CO_2, CH_4, and nitrous oxide separately) before being converted, for reporting, to CO_2-equivalent (CO_2e) emissions by using Intergovernmental Panel on Climate Change (IPCC) Sixth Assessment Report (AR6) 100-year values.

For this study, the default parameters for all pathways for U.S. production are generally used unless otherwise specified. Specifically, for the low-carbon H_2 production cases that require RNG (e.g., RNG-fed ATR with CCS), the NG input is set to 100% RNG in the Main Inputs section and the user-override feature is used to place the upstream emission contribution from RNG (kg CO_2e/kg RNG), which gets included in the total GHG impact results of that specific H_2 production scenario. This approach helps include the impact analysis results of RNG production from the latest attributional LCA of U.S. RNG production pathways (Henriksen et al., 2025 [release forthcoming]), which updates prior published work by this team (Rai, Hage, Littlefield, Yanai, & Skone, 2022). The new report was updated with the biogenic emissions being tracked throughout the production system and essentially looks at two system boundaries: 1) feedstock is treated as a true waste and, thus, has no upstream impacts attributed to it (including biogenic CO_2 uptake) and 2) upstream feedstock impacts are included along with biogenic CO_2 uptake. For the purpose of this LCA, the expanded system case (accounts for displaced emissions from carbon uptake) of anaerobic digestion of MSW is considered. The results from this case range from -7.08 to 11.2 g CO_2e/MJ RNG.

Emission Intensity of Upstream Natural Gas Consumption

The first key input that is expected to lead to variability in regional modeling results is the GHG intensity of upstream natural gas consumption used at the production site. A recently released LCA baseline study by NETL of U.S. natural gas (Khutal, et al., 2024)—and associated model and results—is the latest in a line of studies developed by DOE over the past decade that estimate the total life cycle environmental flows associated with producing and using natural gas from various techno-basins in the U.S. The scope of activities in this model includes all known major activities in the natural gas value chain, e.g., production, gathering and boosting, processing, transmission, storage, and distribution (when applicable). The model is a documented, bottom-up inventory of hundreds of known processes across the natural gas supply chain that lead to GHG and other air emissions (such as those that use energy, or the use of compression and leaky seals). Given the bottom-up nature of the model, individual data sources (such as the U.S. Environmental Protection Agency [EPA] Greenhouse Gas Reporting Program [GHGRP]) and other scientific literature form the basis of the emissions estimates. The bottom-up representation differs from those of top-down studies that use aerial or other measurements to detect GHG emissions and that do not attribute emissions to detailed fuels (oil or gas) and to specific stages (e.g., production, processing). Overall model results are provided for each of the six individual natural gas production stages listed above and aggregated for delivery of U.S. average natural gas to large-scale consumers (at or near transmission pipelines) as well as to local consumers (through the distribution system) representative of the year 2020. In addition, the model provides mean and 95% confidence interval results for the delivery of natural gas from various techno-basins to six regions defined in previous GTI Energy studies, as shown in **Figure 6**. This model estimates CH_4 leakage in the U.S. natural gas system via a bottom-up approach of equipment and sources in each basin, with in an overall average CH_4 emissions rate of 0.56%.

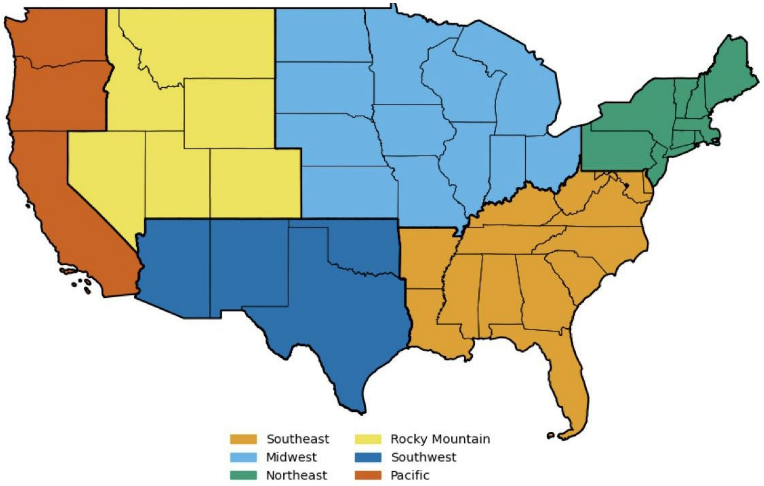

Figure 6. Delivery regions for natural gas in the U.S. used in the NETL NG Baseline (Khutal, et al., 2024)

A summary of the total GHG intensities (across all the six upstream production stages) associated with these delivery regions and the U.S. average is shown in **Table 2**.

Table 2. Summary of GHG intensities of natural gas delivery (Khutal, et al., 2024)

Region	**Mean GHG Intensity (g CO2e/MJ)**
U.S. Average	8.8
Midwest	9.7

Northeast	7.3
Pacific	12.3
Rocky Mountain	12.5
Southeast	11.0
Southwest	10.4

While the regional boundaries between the NETL/GTI and PADD definitions are generally similar, there are differences. To meet the requirements of the project, the values for the PADD-defined regions were found by leveraging results from the NETL/GTI Energy delivery regions. State-level natural gas consumption data from EIA (EIA, 2024e) (as used in the previous Gulf Coast study to apportion delivery region demand) provides a basis to transform values between regional definitions using the NETL baseline study data introduced above. While in the case of the Gulf Coast region, some states required using averages of two different downstream delivery regions within one state, in the East Coast region, most states fall within either the Northeast or the Southeast region. Therefore, to determine the PADD East Coast basin GHG intensity of natural gas production, the NETL/GTI values for the Northeast and Southeast regions assigned to a state based on the highest percentage of supply connection or throughput from that region (i.e., either 7.3 or 10.4 g CO_2e/MJ). In general, since the intensities only vary by about 10% between adjacent regions (and all are within about 20% of the U.S. average), the re-mapping to PADD regions does not add significant uncertainty to the results, as shown in **Table 3**.

Table 3. Natural gas basin and state-level GHG intensities

State	**Gas Supply Region**	**Basin Intensity (g CO2e/MJ)**
Connecticut	*Northeast*	*7.3*
Maine		

Massachusetts		
New Hampshire		
New Jersey		
New York		
Pennsylvania		
Rhode Island		
Vermont		
Delaware	*Southeast*	*10.4*
Florida		
Georgia		
Maryland		
North Carolina		
South Carolina		
Virginia		
West Virginia		

Emission Intensity of Upstream Electricity Consumption

The second key input that is known to significantly vary by region is the life cycle GHG intensity of grid electricity consumed at the production site. This includes the life cycle of electricity from the upstream production of fuels, transport of fuels to a production site, and generation, transmission, and distribution of the electricity.

Past work by DOE and EPA created a series of electricity baseline reports and the Electricity framework. These studies estimate various environmental flows, such as emissions of each species of GHG and other air and water emissions. Results from these efforts were published as a publicly available Grid Mix Explorer tool (NETL, n.d.), and publicly available source code for generating custom grid mixes (EPA, n.d.). Additionally, as a part of the analysis done in prior work (Redublo, et al., 2023) each state in the dataset was first assigned to a PADD region and a Federal Energy Regulatory Commission (FERC) electricity region based on historical regulatory boundaries. This was an important source to help inform the mapping of Balancing Authorities to specific states.

The OHI toolkit provides the contribution of the upstream electricity usage to the overall global warming potential (GWP) of producing 1 kg of H_2. The analysis for each H_2 production pathway is run for every individual balancing authority (this selection can be made in the Main Inputs tab of the toolkit). These numbers are used to generate the average upstream electricity contribution to the overall impact on a state level— which can then be added to the total GWP value (without the upstream electricity impact included).

Results from the Electricity Power Markets report and models provide GHG emission intensity from electricity production for the 10 FERC market regions, and for the 68 balancing authorities in the U.S. The FERC regions for electricity are shown in **Figure 7**.

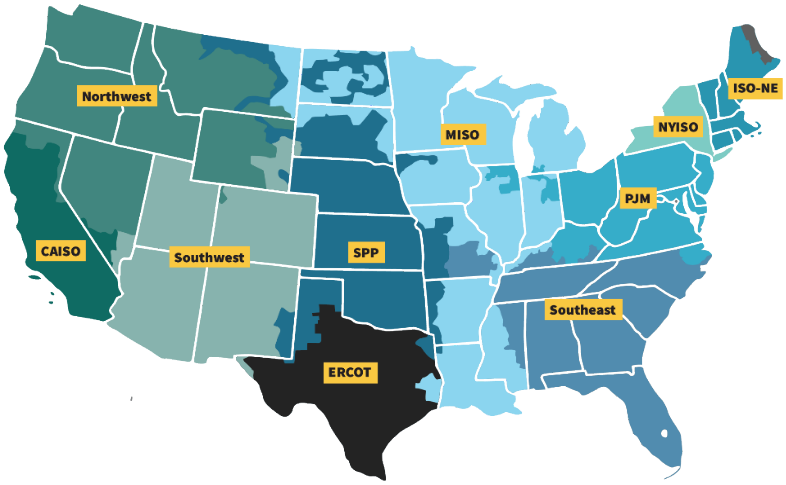

Figure 7. FERC electricity regions (FERC, n.d.)

As an example, **Table 4** summarizes an excerpt of data from the Grid Mix Explorer v4.2 for the GHG intensity of upstream electricity values that can be used in the pathway carbon intensity estimates by region. The NYISO intensity in **Table 4** is an average of NYISO upstate, NYISO Westchester, and NYISO Long Island.

Table 4. Summary of GHG intensities of electricity production (NETL, n.d.)

Region	Mean GHG Intensity (kg CO_2e/MWh)
ISO-NE	245
NYISO	358
PJM (RFC East)	300
PJM (RFC West)	456
Southeast	583

Similar to the conversion mapping of delivered natural gas from the NETL/GTI Energy study regions to the PADD regions, values from the FERC regions will be aligned with the PADD regions based on state electricity consumption data from EIA. EIA's Electricity Data Browser is a comprehensive tool that offers detailed data on electricity generation, consumption, and other related metrics across various regions and timeframes.

Based on previous work, **Table 5** shows an example mapping of the state to FERC regions.

Table 5. Mapping of states to FERC regions (FERC, n.d.)

State	FERC Region
DC	PJM
Connecticut	ISO-NE
New York	NYISO
Florida	SERC
State	FERC Region

A weighted GHG intensity for each region is found by combining the GHG intensities of states via a consumption-weighted average, as in the following equation:

$$\text{Weighted GHG Intensity} = \frac{\sum(E_i \times I_i)}{\sum E_i}$$

where E_i is the electricity consumption of state i (MWh) and I_i is the GHG intensity of state i in kg CO_2e/MWh. In general, since the intensities only vary by about 15% between adjacent regions (and all are within about 20% of the U.S. average), the re-mapping to PADD regions is not expected to significant change the results.

This same method will be used to derive region-specific upstream electricity GHG intensity values to be used as inputs of the carbon intensity estimates for all regions and all pathways in the study. Detailed data is demonstrated in **Table 6** below.

Table 6. Electricity balancing authority (BA) and state-level GHG intensities

State	BAs	BA Annual Net Generation	BA Intensity (kg CO_2e/MWh)	State Intensity (kg CO_2e/MWh)
Connecticut	ISO-NE	102.14	247.33	247.33
Delaware	PJM	822.99	326.32	326.32
D.C.	PJM	822.99	326.32	326.32
Florida	Duke Energy Florida Inc	46.93	441.26	367.97
	Florida Power & Light Company	139.87	271.52	
	Florida Municipal Power Pool	13.63	524.50	
	JEA	9.82	531.53	
	Seminole Electric Cooperative	12.63	550.52	
	Southern Co	250.51	383.95	
Georgia	Southern Co	250.51	383.95	383.95
Maine	ISO-NE	102.14	247.33	247.33

State	BAs	BA Annual Net Generation	BA Intensity (kg CO_2e/MWh)	State Intensity (kg CO_2e/MWh)
Maryland	PJM	822.99	326.32	326.32
Massachusetts	ISO-NE	102.14	247.33	247.33
New Hampshire	ISO-NE	102.14	247.33	247.33
New Jersey	PJM	822.99	326.32	326.32
New York	NYISO	129.71	218.02	218.02
North Carolina	Duke Energy Carolinas	108.36	220.58	220.06
	Duke Energy Progress East	66.95	219.34	
	Duke Energy Progress West	0.04	0.00	
Pennsylvania	PJM	822.99	326.32	326.32
Rhode Island	ISO-NE	102.14	247.33	247.33
South Carolina	Duke Energy Carolinas	108.36	220.58	220.58
Vermont	ISO-NE	102.14	247.33	247.33
Virginia	PJM	822.99	326.32	326.32

State	BAs	BA Annual Net Generation	BA Intensity (kg CO_2e/MWh)	State Intensity (kg CO_2e/MWh)
West Virginia	PJM	822.99	326.32	326.32

Detailed Inputs in OHI Toolkit

The following tables provide the detailed assumptions used within the OHI toolkit for the H_2 production pathways, showing all detailed and customized assumptions used. Subsequent sections show details for RNG and SNG modeling. Note that there are various rows without explicit entries (e.g., “Not Selected”) that are maintained here for transparency to aid in replication efforts, e.g., to duplicate results in the OHI tool and ensure the right parameters are used or selected in the commensurate cells of the tool.

Table 7. Assumptions used for H_2 production pathways in OHI toolkit

H2-1	NG-fed w/ CCS	
Natural Gas Mix	100% Fossil Natural Gas	
Electricity Mix	100% Grid electricity	
Where does captured CO2 go downstream	Saline Aquifer Storage	
Where is CO2 captured in the system?	From shifted gas using MDEA and flue gas MEA	

	(90% net capture)	
Grid Electricity Location	United States of America (the)	
Balancing Authority	U.S. Average	
Process Definition		
Natural Gas	3.73	kg
Water	4.9	kg
Embodied Emissions	1.45E-04	kg CO_2e
Captured CO2	9.81	kg
Carbon Dioxide	1.09	kg
Electricity Co-product	0.05	kWh
Default Electricity Mix		
Biomass	0.70%	
Coal	17.20%	
Geothermal	0.50%	

Hydroelectric	9.80%	
Natural Gas	40.00%	
Nuclear	19.70%	
Oil	0.10%	
Solar Photovoltaic	3.80%	
Solar Thermal	0.10%	
Storage	0.00%	
Wind	8.20%	
Other	0.00%	
RNG Customization Type	Default	
Carbon Management Type	Default	
Natural Gas		
Country where natural gas is being sources from	United States of America (the)	
Do you want to use default impact values for all	Yes	

stages?		
Is the distribution stage relevant to your system?	No	
Is there a storage step in your system?	Yes	
Select upstream production techno-basin:	U.S. Average	
Select downstream delivery region:	Southeast or Northeast based on the state the scenario is run for	
H2-2	NG-fed ATR w/ CSS	
Natural Gas Mix	100% Fossil Natural Gas	
Electricity Mix	100% Grid electricity	
Is there a nitrogen co-product?	Yes	
Where does captured CO2 go downstream?	Saline Aquifer Storage	
Grid Electricity Location	United States of America (the)	
Balancing Authority	U.S. Average	
Process Definition		
Electricity	4.006545455	kWh

Natural Gas	3.524727273	kg
Water	24.35247273	kg
Embodied Emissions	0.000151023	kg CO_2e
Captured CO2	8.81	kg
Carbon Dioxide	0.52	kg
Nitrogen (co-product)	14.65	kg
Grid Mix Type	Conventional Mix	
Default Electricity Mix		
Biomass	0.6%	
Coal	16.9%	
Geothermal	0.0%	
Hydroelectric	1.3%	
Natural Gas	41.1%	
Nuclear	35.8%	

Oil	0.1%	
Solar Photovoltaic	0.8%	
Solar Thermal	0.0%	
Storage	0.0%	
Wind	3.4%	
Other	0.0%	
Carbon Management Type	0.6%	
Natural Gas		
Country where natural gas is being sources from	United States of America (the)	
Do you want to use default impact values for all stages?	Yes	
Is the distribution stage relevant to your system?	No	
Is there a storage step in your system?	Yes	
Select upstream production techno-basin:	U.S. Average	

Select downstream delivery region:	Southwest	
Include avoided emissions?	Yes	
H2-3	RNG-fed SMR w/o CSS	
Natural Gas Mix	100% Renewable Natural Gas	
Electricity Mix	100% Grid electricity	
Is there a nitrogen co-product?	No	
Grid Electricity Location	United States of America (the)	
Balancing Authority	U.S. Average	
Process Definition		
Electricity	0	kWh
Natural Gas	3.4	kg
Water	6.31	kg
Embodied Emissions	0.000123033	kg CO_2e
Carbon Dioxide	9	kg

Electricity (co-product)	1.1	kWh
Grid Mix Type	Conventional Mix	
Default Electricity Mix		
Biomass	0.007	
Coal	0.172	
Geothermal	0.005	
Hydroelectric	0.098	
Natural Gas	0.4	
Nuclear	0.197	
Oil	0.001	
Solar Photovoltaic	0.038	
Solar Thermal	0.001	
Storage	0	
Wind	0.082	

Other	0	
RNG Customization Type	Default	
Include avoided emissions?	Yes	
H2-4	RNG-fed ATR w/o CSS	
Natural Gas Mix	100% Renewable Natural Gas	
Electricity Mix	100% Grid electricity	
Is there a co-product?	Yes	
Is there a nitrogen co-product	Yes	
Grid Electricity Location	United States of America (the)	
Balancing Authority	U.S. Average	
Process Definition		
Electricity	3.25	kWh
Natural Gas	3.52	kg
Water	24.35	kg

Embodied Emissions	0.000151023	kg CO_2e
Carbon Dioxide	9.33	kg
Nitrogen (co-product)	14.65	kg
Grid Mix Type	Conventional Mix	
Default Electricity Mix		
Biomass	0.007	
Coal	0.172	
Geothermal	0.005	
Hydroelectric	0.098	
Natural Gas	0.4	
Nuclear	0.197	
Oil	0.001	
Solar Photovoltaic	0.038	
Solar Thermal	0.001	

Storage	0	
Wind	0.082	
Other	0	
RNG Customization Type	User Override	
RNG User Override	-0.35	kg CO_2e/kg RNG
Include avoided emissions?	Yes	
H2-5	RNG-fed SMR w CCS	
Natural Gas Mix	100% Renewable Natural Gas	
Electricity Mix	100% Grid electricity	
Where is CO2 captured in the system	From shifted gas using MDEA and flue gas MEA (90% net capture)	
Where does captured CO2 go downstream	Saline Aquifer Storage	

Grid Electricity Location	United States of America (the)	
Balancing Authority	U.S. Average	
Process Definition		
Inputs		
Electricity	1	kWh
Natural Gas	3.74	kg
Water	4.45	kg
Embodied Emissions	0.000128373	kg CO_2e
Outputs		
Captured CO2	8.9	kg
Carbon Dioxide	0.99	kg
Electricity Co-product	0.05	kWh
Electricity		
Default Electricity Mix		

Biomass	0.70%	
Coal	17.20%	
Geothermal	0.50%	
Hydroelectric	9.80%	
Natural Gas	40.00%	
Nuclear	19.70%	
Oil	0.10%	
Solar Photovoltaic	3.80%	
Solar Thermal	0.10%	
Storage	0.00%	
Wind	8.20%	
Other	0.00%	
RNG		
RNG Customization Type	User Override	

RNG User Override	-0.35	kg CO_2e/kg RNG
Carbon Management		
Carbon Management Type	Default	
Results		
Include avoided emissions?	Yes	
H2-6	RNG-fed ATR w CCS	
Natural Gas Mix	100% Renewable Natural Gas	
Electricity Mix	100% Grid electricity	
Is there a nitrogen co-product?	Yes	
Where does captured CO2 go downstream	Saline Aquifer Storage	
Grid Electricity Location	United States of America (the)	
Balancing Authority	U.S. Average	
Process Definition		

Inputs		
Electricity	4.01	kWh
Natural Gas	3.52	kg
Water	24.35	kg
Embodied Emissions	0.000151023	kg CO_2e
Outputs		
Captured CO2	8.81	kg
Carbon Dioxide	0.52	kg
Nitrogen Co-product	14.65	kg
Electricity		
Default Electricity Mix		
Biomass	0.70%	
Coal	17.20%	
Geothermal	0.50%	

Hydroelectric	9.80%	
Natural Gas	40.00%	
Nuclear	19.70%	
Oil	0.10%	
Solar Photovoltaic	3.80%	
Solar Thermal	0.10%	
Storage	0.00%	
Wind	8.20%	
Other	0.00%	
RNG		
RNG Customization Type	Default	
Carbon Management		
Carbon Management Type	Default	
Results		

Include avoided emissions?	Yes	
H2-7	Plasma Pyrolysis	
What is used for facility heating?	Natural Gas	
Is there a co-product?	No	
Process Definition		
Inputs		
Electricity	0.0403	kWh
Natural Gas	5.43	kg
Water	252.15	kg
Outputs		
Carbon dioxide	2.61	kg
Methane	0.03	kg
Nitrous oxide	0	kg
H_2 (fugitive)	0	kg

Note the following scenario is 8C due to its lack of nuclear in the mix but is listed as H2-8 in the LCA results of this intermediate report. 8A and 8B were used as comparative cases and are not otherwise shown in the report. The low C electricity mix for this scenario is calculated using the current U.S. average renewable share in the existing grid mix (default values in the OHI toolkit) and sum up the values of the renewable energy options in it (this sum is 23.1%). Then a scaling factor is used to proportionally expand these values so that their contribution reaches 100%, while reducing the contribution of non-renewable sources to 0.

Additionally, the Plasma Pyrolysis scenario (H2-7) has process definition modified from OHI tool default values to inputs from an OpenLCA model developed for an NETL unit process modeling project.

Table 8. Assumptions used for H_2 production pathways in OHI toolkit, continued

H2-8	Electrolysis with low-C electricity (PEM Electrolysis)	
Note: The same approach used as 8B but the H_2 production pathway is PEM Electrolysis to keep the method consistent with TEA		
Is there an oxygen co-product?	Yes	
Natural Gas Mix	100% Fossil Natural Gas	
Electricity Mix	100% Grid Electricity	

Grid Electricity Location	United States of America (the)	
Balancing Authority	U.S. Average	
Process Definition		
Inputs		
Electricity	38.6	
Natural Gas	0.61	kWh
Water	215	kg
Embodied Emissions	0.00140827	kg
Outputs		kg CO_2e
H_2 (fugitive)	0.034	
Oxygen Co-product	14.65	kg
Electricity		kg
Default Electricity Mix		

Biomass	3.00%	
Coal	0.00%	
Geothermal	2.20%	
Hydroelectric	42.40%	
Natural Gas	0.00%	
Nuclear	0.00%	
Oil	0.00%	
Solar Photovoltaic	16.50%	
Solar Thermal	0.40%	
Storage	0.00%	
Wind	35.50%	
Other	0.00%	
Natural Gas		
Country where natural gas is being sources from	United States of America	

	(the)	
Do you want to use default impact values for all stages?	Yes	
Is the distribution stage relevant to your system?	No	
Is there a storage step in your system?	Yes	
Select upstream production techno-basin:	U.S. Average	
Select downstream delivery region:	Southwest	
Results		
Include avoided emissions?	Yes	
H2-8a	**PEM Electrolysis with Solar**	
Is there an oxygen co-product?	Yes	
Natural Gas Mix	100% Fossil Natural Gas	
Electricity Mix	100% Grid Electricity	

Grid Electricity Location	United States of America (the)	
Balancing Authority	U.S. Average	
Process Definition		
Inputs		
Electricity	38.6	
Natural Gas	0.61	kWh
Water	215	kg
Embodies Emissions	0.001408269	kg
Outputs		kg CO_2e
H_2 (fugitive)	0.034	
Oxygen Co-product	14.65	kg
Electricity		kg
Default Electricity Mix		

Biomass	0.00%	
Coal	0.00%	
Geothermal	0.00%	
Hydroelectric	0.00%	
Natural Gas	0.00%	
Nuclear	0.00%	
Oil	0.00%	
Solar Photovoltaic	50.00%	
Solar Thermal	50.00%	
Storage	0.00%	
Wind	0.00%	
Other	0.00%	
Natural Gas		
Country where natural gas is being sources from	United States of America	

	(the)	
Do you want to use default impact values for all stages?	Yes	
Is the distribution stage relevant to your system?	No	
Is there a storage step in your system?	Yes	
Select upstream production techno-basin:	U.S. Average	
Select downstream delivery region:	Southwest	
Results		
Include avoided emissions?	Yes	
H2-8b	**PEM Electrolysis with Wind**	
Is there an oxygen co-product?	Yes	
Natural Gas Mix	100% Fossil Natural Gas	
Electricity Mix	100% Grid Electricity	

Grid Electricity Location	United States of America (the)	
Balancing Authority	U.S. Average	
Process Definition		
Inputs		
Electricity	38.6	
Natural Gas	0.61	kWh
Water	215	kg
Embodies Emissions	0.001408269	kg
Outputs		kg CO_2e
H_2 (fugitive)	0.034	
Oxygen Co-product	14.65	kg
Electricity		kg
Default Electricity Mix		

Biomass	0.00%	
Coal	0.00%	
Geothermal	0.00%	
Hydroelectric	0.00%	
Natural Gas	0.00%	
Nuclear	0.00%	
Oil	0.00%	
Solar Photovoltaic	0.00%	
Solar Thermal	0.00%	
Storage	0.00%	
Wind	100.00%	
Other	0.00%	
Natural Gas		
Country where natural gas is being sources from	United States of America	

	(the)	
Do you want to use default impact values for all stages?	Yes	
Is the distribution stage relevant to your system?	No	
Is there a storage step in your system?	Yes	
Select upstream production techno-basin:	U.S. Average	
Select downstream delivery region:	Southwest	
Results		
Include avoided emissions?	Yes	
H2-8c	**PEM Electrolysis with Nuclear**	
Is there an oxygen co-product?	Yes	
Natural Gas Mix	100% Fossil Natural Gas	
Electricity Mix	100% Grid Electricity	

Grid Electricity Location	United States of America (the)	
Balancing Authority	U.S. Average	
Process Definition		
Inputs		
Electricity	38.6	
Natural Gas	0.61	kWh
Water	215	kg
Embodies Emissions	0.001408269	kg
Outputs		kg CO_2e
H_2 (fugitive)	0.034	
Oxygen Co-product	14.65	kg
Electricity		kg
Default Electricity Mix		

Biomass	0.00%	
Coal	0.00%	
Geothermal	0.00%	
Hydroelectric	0.00%	
Natural Gas	0.00%	
Nuclear	100.00%	
Oil	0.00%	
Solar Photovoltaic	0.00%	
Solar Thermal	0.00%	
Storage	0.00%	
Wind	0.00%	
Other	0.00%	
Natural Gas		
Country where natural gas is being sources from	United States of America	

	(the)	
Do you want to use default impact values for all stages?	Yes	
Is the distribution stage relevant to your system?	No	
Is there a storage step in your system?	Yes	
Select upstream production techno-basin:	U.S. Average	
Select downstream delivery region:	Southwest	
Results		
Include avoided emissions?	Yes	
H2-8d	**PEM Electrolysis with Hydroelectric**	
Is there an oxygen co-product?	Yes	
Natural Gas Mix	100% Fossil Natural Gas	
Electricity Mix	100% Grid Electricity	

Grid Electricity Location	United States of America (the)	
Balancing Authority	U.S. Average	
Process Definition		
Inputs		
Electricity	38.6	
Natural Gas	0.61	kWh
Water	215	kg
Embodies Emissions	0.001408269	kg
Outputs		kg CO_2e
H_2 (fugitive)	0.034	
Oxygen Co-product	14.65	kg
Electricity		kg
Default Electricity Mix		

Biomass	0.00%	
Coal	0.00%	
Geothermal	0.00%	
Hydroelectric	100.00%	
Natural Gas	0.00%	
Nuclear	0.00%	
Oil	0.00%	
Solar Photovoltaic	0.00%	
Solar Thermal	0.00%	
Storage	0.00%	
Wind	0.00%	
Other	0.00%	
Natural Gas		
Country where natural gas is being sources from	United States of America	

	(the)	
Do you want to use default impact values for all stages?	Yes	
Is the distribution stage relevant to your system?	No	
Is there a storage step in your system?	Yes	
Select upstream production techno-basin:	U.S. Average	
Select downstream delivery region:	Southwest	
Results		
Include avoided emissions?	Yes	
H2-8e	**PEM Electrolysis with Bioelectric**	
Is there an oxygen co-product?	Yes	
Natural Gas Mix	100% Fossil Natural Gas	
Electricity Mix	100% Grid Electricity	

Grid Electricity Location	United States of America (the)	
Balancing Authority	U.S. Average	
Process Definition		
Inputs		
Electricity	38.6	
Natural Gas	0.61	kWh
Water	215	kg
Embodies Emissions	0.001408269	kg
Outputs		kg CO_2e
H_2 (fugitive)	0.034	
Oxygen Co-product	14.65	kg
Electricity		kg
Default Electricity Mix		

Biomass	100.00%	
Coal	0.00%	
Geothermal	0.00%	
Hydroelectric	0.00%	
Natural Gas	0.00%	
Nuclear	0.00%	
Oil	0.00%	
Solar Photovoltaic	0.00%	
Solar Thermal	0.00%	
Storage	0.00%	
Wind	0.00%	
Other	0.00%	
Natural Gas		
Country where natural gas is being sources from	United States of America	

	(the)	
Do you want to use default impact values for all stages?	Yes	
Is the distribution stage relevant to your system?	No	
Is there a storage step in your system?	Yes	
Select upstream production techno-basin:	U.S. Average	
Select downstream delivery region:	Southwest	
Results		
Include avoided emissions?	Yes	
H2-8(a+b)	**PEM Electrolysis with Solar+Wind**	
Is there an oxygen co-product?	Yes	
Natural Gas Mix	100% Fossil Natural Gas	
Electricity Mix	100% Grid Electricity	

Grid Electricity Location	United States of America (the)	
Balancing Authority	U.S. Average	
Process Definition		
Inputs		
Electricity	38.6	
Natural Gas	0.61	kWh
Water	215	kg
Embodies Emissions	0.001408269	kg
Outputs		kg CO_2e
H_2 (fugitive)	0.034	
Oxygen Co-product	14.65	kg
Electricity		kg
Default Electricity Mix		

Biomass	0.00%	
Coal	0.00%	
Geothermal	0.00%	
Hydroelectric	0.00%	
Natural Gas	0.00%	
Nuclear	0.00%	
Oil	0.00%	
Solar Photovoltaic	25.00%	
Solar Thermal	25.00%	
Storage	0.00%	
Wind	50.00%	
Other	0.00%	
Natural Gas		
Country where natural gas is being sources from	United States of America	

	(the)	
Do you want to use default impact values for all stages?	Yes	
Is the distribution stage relevant to your system?	No	
Is there a storage step in your system?	Yes	
Select upstream production techno-basin:	U.S. Average	
Select downstream delivery region:	Southwest	
Results		
Include avoided emissions?	Yes	

It is important to note that three different scenarios were run for the electrolysis case; the overall results have only been reported for PEM in order to remain consistent through reporting.

RNG-Specific Modeling Details

The following table (**Table 9**) summarizes the specific parameters used for analysis of RNG for the cited work above. The report evaluates several feedstocks (e.g., MSW, animal manure, wastewater sludge) and technologies (anaerobic digestion, LFG recovery, and thermal gasification), comparing the GWP results under two system boundary cases: the "true waste" case, where feedstocks are considered burden-free waste, and the "expanded system" case, which includes the upstream impacts of feedstock production and credits for co-products and biogenic carbon uptake. The report incorporates process data from GREET, WARM, OHI, and NETL databases, and modeling is conducted in openLCA using IPCC AR6 100-year characterization factors. For the anaerobic digestion of MSW in the expanded system case, the analysis finds a net-negative climate impact, with a lower bound GWP of -0.37 kg CO_2e/kg RNG, largely due to avoided emissions and biogenic CO_2 uptake outweighing the emissions from processing. This is the value used as the upstream RNG emissions impact input for calculating the GWP of RNG-based H_2 pathways.

Production Pathway	GWP (kg CO_2e/MJ RNG)	GWP (kg CO_2e/kg RNG)
Woody Feedstock (Air Gasification)	0.222	11.766
MSW (Anaerobic Digestion)	-0.00708	-0.37524
Process Inventories for RNG production pathways		
Syngas Cleanup [Air/Catalyst]	1.05	MJ dirty syngas/MJ clean syngas
Methanation [Air/Catalyst]	1.19	MJ dirty syngas/MJ RNG
Biogas Cleaning/Upgrading [MSW, Anaerobic Digestion]	0.0362	kg biogas/MJ RNG
Electricity Requirements		
Woody Feedstock (Air Gasification)	0.0752	MJ/MJ dirty syngas
MSW (Anaerobic Digestion)	2.21	MJ/kg biogas

Table 9. RNG-Specific Modeling Details

SNG-Specific Modeling Details

Table 10 describes parameters needed for the SNG pathways analysis, taken from the openLCA model for SNG. The openLCA modeling for SNG production used in this analysis was developed to evaluate the life cycle GHG emissions associated with producing SNG through various CO_2 utilization (CO_2U) pathways. The model simulates cradle-to-gate impacts of SNG production using different combinations of H_2 sources (such as electrolysis powered by grid electricity or biomass gasification) and point-source CO_2 from facilities like cement, ethanol, or steel plants. The functional unit is 1 MJ of SNG, and the modeling incorporates assumptions about upstream energy use, process energy inputs, and methanation efficiency. The openLCA model uses IPCC AR6 100-year GWPs and includes system expansion in select cases to account for displaced grid electricity or other co-products. The model assumes that CO_2 is captured and delivered to the methanation reactor with minimal losses and that H_2 production is the dominant contributor to total GHG emissions, with electricity source and efficiency being key drivers.

The current SNG openLCA model includes multiple H_2 production pathways, each broadly defined and intended to feed into the SNG production process. Separate openLCA models are available for CCS units, and specific flows from these can be imported into the SNG model as proxies to construct targeted scenarios for GHG results. However, incorporating these external CCS flows into each H_2 production pathway requires careful alignment of reference flows and system boundaries, which can be time intensive. Among the available H_2 production technologies—PEM, Solid Oxide, and Alkaline Electrolysis—only the Alkaline Electrolysis pathway currently includes integrated CO_2 capture from NGCC and ethanol processes. As a result, this pathway was selected for use in the current analysis to streamline integration and maintain internal consistency within the model.

Table 10. SNG-Specific Modeling Details

Catalytic Methanation (AE+Cement CO_2)								
Inputs				**Contribution Tree**				
Input flow	Amount	Unit	Provider	Process	Required amount	Unit	Total result [kg CO2e]	Direct contribution [kg CO2e]
Carbon dioxide, processed	2.644120739	kg	Cement retrofit; capture unit (95% capture)	H_2 mixer	0.481951316	kg	14.95390962	0

Electricity, AC, 120 V	1.65834311	kWh		Electricity; at user; consumption mix - US - US	5.970035197	MJ	0.985215807	0
H_2, >99.90 vol%, 925 psig (6.48 MPa)	0.481951316	kg		Steel, sections, production - GLO	0.075745942	kg	0.122719712	0.122719712
Natural gas, delivered	5.72E-06	kg		Natural gas emissions profile, US weighted average - 2017	5.72E-06	kg	4.52E-06	4.52E-06
Nickel-based catalyst	6.33E-04	kg		Cement retrofit; capture unit (95% capture)	2.644120739	kg	-2.333440188	-2.644120739
Steel	0.075745942	kg						
Air	1.688223166	kg						
Water	0.003406326	kg						
Outputs				**Impact Analysis**				
Syngas	1	kg		Global warming potential [100 yr] - TRACI 2.1 (NETL)	13.72840947	kg CO2e		
Water	2.126662977	kg		Carbon dioxide	12.57886589	kg CO2e		
				Methane	1.083997553	kg CO2e		
Catalytic Methanation (AE+CO2 at ethanol plant)								
Inputs				**Contribution Tree**				
Input flow	Amount	Unit	Provider	Process	Required amount	Unit	Total result [kg CO2e]	Direct contribution [kg CO2e]
Carbon dioxide, processed	2.644120739	kg	Carbon dioxide processing, ethanol plant - US	H_2 mixer	0.481951316	kg	14.95390962	0
Electricity, AC, 120 V	1.65834311	kWh		Electricity; at user; consumption mix - US - US	5.970035197	MJ	0.985215807	0

H_2, >99.90 vol%, 925 psig (6.48 MPa)	0.481951316	kg		Steel, sections, production - GLO	7.57E-02	kg	1.23E-01	0.122719712
Natural gas, delivered	5.72E-06	kg		Natural gas emissions profile, US weighted average - 2017	5.72E-06	kg	4.52E-06	4.52E-06
Nickel-based catalyst	6.33E-04	kg		Carbon dioxide processing, ethanol plant - US	2.644120739	kg	-1.559953752	0
Catalytic Methanation (AE+Cement CO2)								
Steel	0.075745942	kg						
Air	1.688223166	kg						
Water	0.003406326	kg						
Outputs				**Impact Analysis**				
Syngas	1	kg		Global warming potential [100 yr] - TRACI 2.1 (NETL)	14.5018959	kg CO2e		
Water	2.126662977	kg		Carbon dioxide	13.21554066	kg CO2e		
				Methane	1.137718094	kg CO2e		
Catalytic Methanation (AE+NGCC CO2)								
Inputs				**Contribution Tree**				
Input flow	Amount	Unit	Provider	Process	Required amount	Unit	Total result [kg CO2e]	Direct contribution [kg CO2e]
Carbon dioxide, processed	2.644120739	kg	NGCC Power Plant, capture, cradle-to-gate - US-IL	H_2 mixer	0.481951316	kg	14.95390962	0

Electricity, AC, 120 V	1.65834311	kWh		NGCC power plant, capture, cradle-to-gate - US-IL	2.644120739	kg	1.037049458	1.037049458
H_2, >99.90 vol%, 925 psig (6.48 MPa)	0.481951316	kg		Electricity; at user; consumption mix - US - US	5.970035197	MJ	0.985215807	0
Natural gas, delivered	5.72E-06	kg		Steel, sections, production - GLO	0.075745942	kg	0.122719712	0.122719712
Nickel-based catalyst	6.33E-04	kg		Natural gas emissions profile, US weighted average - 2017	5.72E-06	kg	4.52E-06	4.52E-06
Steel	0.075745942	kg						
Air	1.688223166	kg						
Water	0.003406326	kg						
Outputs				**Impact Analysis**				
Syngas	1	kg		Global warming potential [100 yr] - TRACI 2.1 (NETL)	17.09889911	kg CO_2e		
Water	2.126662977	kg		Carbon dioxide	15.44862278	kg CO_2e		
				Methane	1.585241607	kg CO_2e		
Catalytic Methanation (AE+Steel CO_2)								
Inputs				**Contribution Tree**				
Input flow	Amount	Unit	Provider	Process	Required amount	Unit	Total result [kg CO_2e]	Direct contribution [kg CO_2e]
Catalytic Methanation (AE+Cement CO_2)								
Carbon dioxide, processed	2.644120739	kg	Steel, sections, production w/ CC - GLO	H_2 mixer	0.481951316	kg	14.95390962	0
Electricity, AC, 120	1.65834311	kWh		Steel, sections, production w/ CC -	2.644120739	kg	3.60284894	3.021064578

V				GLO			2	
H_2, >99.90 vol%, 925 psig (6.48 MPa)	0.481951316	kg		Electricity; at user; consumption mix - US - US	5.970035197	MJ	0.985215807	0
Natural gas, delivered	5.72E-06	kg		Steel, sections, production - GLO	0.075745942	kg	0.122719712	0.122719712
Nickel-based catalyst	6.33E-04	kg		Natural gas emissions profile, US weighted average - 2017	5.72E-06	kg	4.52E-06	4.52E-06
Steel	0.075745942	kg						
Air	1.688223166	kg						
Water	0.003406326	kg						
Outputs				**Impact Analysis**				
Syngas	1	kg		Global warming potential [100 yr] - TRACI 2.1 (NETL)	19.6646986	kg CO2e		
Water	2.126662977	kg		Carbon dioxide	18.16539554	kg CO2e		
				Methane	1.383595457	kg CO2e		

Appendix E: Cost-Benefit Analysis (CBA)

Methodology

The CBA synthesizes the results of the NEMS model, TEA study, and LCA study to identify the most viable technology pathway to net-zero. The CBA adds one key metric in the form of the "Required Incentive" calculation, which provides an alternative metric for evaluating each technology. Related to discussions around the implementation of a carbon tax or carbon credits (45Q and 45V are known examples of ways these can be implemented), it can theoretically provide lawmakers with an idea of what economic stimulus would be necessary to promote the adoption of some of the technologies being explored by this study. This is essentially a "break-even" CO_2 emissions price, which can be interpreted either as a cost avoided in the case of a tax, or an additional revenue stream in the case of a credit.

The incentives were calculated using the following equation:

$$\text{Required Incentive} = \frac{\text{LC}_{\text{Renew}} - \text{LC}_{\text{NG}}}{\text{CI}_{\text{NG}} - \text{CI}_{\text{Renew}}}$$

where LC is the levelized fuel cost of the renewable fuel or natural gas respectively, in \$/MMBtu, and CI is the carbon intensity of the fuel in tons of CO_2/MMBtu. These numbers were all calculated based on the mass higher heating values of the fuels in question, which were assumed to be 22,500 Btu/lb for natural gas and all similar fuels and 61,084 Btu/lb for H_2. Both of these numbers were acquired from Engineering Toolbox (2005).

Assumptions

The CBA synthesizes the results of the NEMS model, TEA study, and LCA study to identify the most viable technology pathway to net-zero. All assumptions and methodologies used for these studies, thus, also apply to the CBA.

Findings

The LCA results for MSW using biodigesters were the only East Coast cases to show net-negative CO_2 emissions. Although these results are based on different assumptions than the TEA (which used thermal gasification), the levelized cost from the TEA was used as a proxy, given the similar feedstocks and comparable cost structures. This approach aligns with findings from Pratson, Fay, and Parvathukar (2023), and yielded an estimated incentive of $435/ton CO_2 in the best case (Georgia), driven primarily by the highly negative emissions.

Further justification of the results is provided by several references from DOE's Clean Hydrogen Liftoff Report (Howe, et al., 2024), the Electric Power Research Institute and GTI Energy Regional Pipeline Costs Study using their REGEN model (EPRI, 2024), and DOE's Cost and Performance Baseline Volume 1 Report on fossil energy plants (Schmitt, et al., 2022). Other references were provided solely for background information.

Appendix F: Estimated End-Use Demand in the Region

Due to limited access to resources, only H_2 and natural gas demand data are available for all regions. These data are broken down by state using 2024 demand numbers and were generously provided by the sponsors of this study. For natural gas, 2023 consumption data were used as a stand-in for demand.

The H_2 demand data are summarized in **Table 11** and **Table 12**. These data are from Evolved Energy Research's 2024 U.S. Annual Decarbonization Perspective Baseline Scenario (Evolved Energy Research 2025). Unlike the Gulf Coast, the East Coast generally has minimal demand for H_2, even in the energy-rich state of Pennsylvania, with only the two aforementioned states having a total demand higher than even 1 petajoule due mostly to the influence of the petroleum industry. Most of the states in the region appear to have some minor demand from the transportation sector as well as ammonia production. The East Coast does not have any significant use for H_2 in the power generation, electric fuels, or iron and steel industries. (Note that some areas were technically non-zero but failed to meet a minimum threshold of significance.) The current total demand for H_2 is summarized in **Figure 8.**

Table 11. 2024 H_2 demand by sector (petajoules)

State	Power Generation	Electric Fuels	Transportation	Ammonia Production	Petroleum Refineries	Iron and Steel	Other Industry	Total
Connecticut	0	0	0.000933742	0.01322	0	0	0	0.01415
Delaware	0	0	0	0	0	0	0	0
Florida	0	0	0.002949654	0.05377	0	0	0	0.05672
Georgia	0	0	0.007862884	25.90245	16.70342	0	5.91798	48.53171
Maine	0	0	0.000933742	0.01322	0	0	0	0.01415
Maryland	0	0	0	0	0	0	0	0
Massachusetts	0	0	0.000933742	0.01322	0	0	0	0.01415
New Hampshire	0	0	0.000933742	0.01322	0	0	0	0.01415
New Jersey	0	0	0	0	0	0	0	0
New York	0	0	0.004726893	0.61869	0	0	0	0.62342
North Carolina	0	0	0.003518025	0.10602	0	0	0	0.10954
Pennsylvania	0	0	0	0	0	0	0	0
Rhode Island	0	0	0.000933742	0.01322	0	0	0	0.01415
South Carolina	0	0	0.003518025	0.10602	0	0	0	0.10954
Vermont	0	0	0.000933742	0.01322	0	0	0	0.01415
Virginia	0	0	0.014195509	11.98712	23.68854	0	3.23585	38.92571
West Virginia	0	0	0	0	0	0	0	0
Total	**0**	**0**	**0.042373442**	**38.85339**	**40.39196**	**0**	**9.15383**	**88.44154**

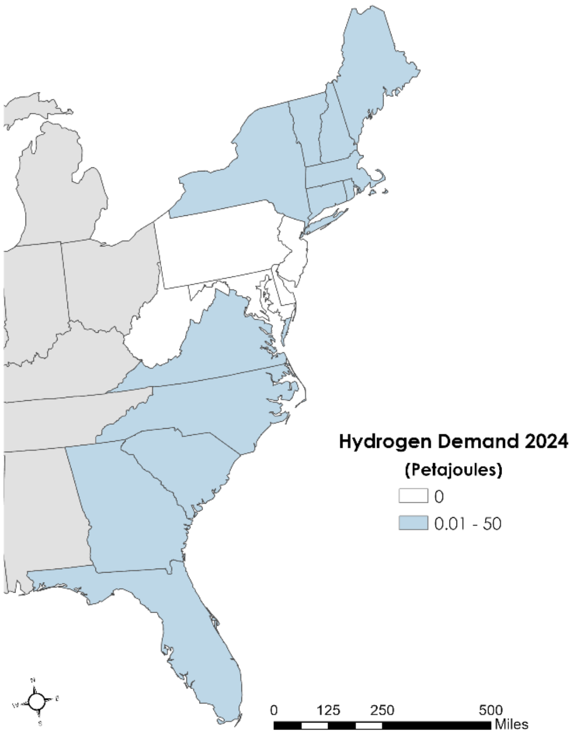

Figure 8. H_2 demand by state (2024)

Table 12. Projected 2050 H2 demand by state

2050 H2 Demand (PJ)			
	1A	1B	1C
Ammonia Production	0.36503307	1.569905912	44.0739767
Electric Fuels	0.203659767	1.322708638	0.453557241
Iron and Steel	0.000495588	0.005684921	0.012873045
Other Industry	0	0	11.43844491
Petroleum Refinery	0	0	40.26656815
Power Generation	0.179985504	0.412351422	0.763783936
2050 H2 Demand (MMBtu)			
	1A	1B	1C
Ammonia Production	346216.12	1488979.433	41802024.14
Electric Fuels	193161.3876	1254524.837	430176.9924
Iron and Steel	470.0414773	5391.871184	12209.45733
Other Industry	0	0	10848808.89

Petroleum Refinery	0	0	38190882.24
Power Generation	170707.5002	391095.2764	724411.9303
2050 H2 Demand (KMMBtu)			
	1A	1B	1C
Power Generation	170.7075002	391.0952764	724.4119303
Iron and Steel	0.470041477	5.391871184	12.20945733
Electric Fuels	193.1613876	1254.524837	430.1769924
Ammonia Production	346.21612	1488.979433	41802.02414
Petroleum Refinery	0	0	38190.88224
Other Industry	0	0	10848.80889

Finally, the overall annual natural gas consumption rates for each state in 2023 are summarized in **Figure 9**.

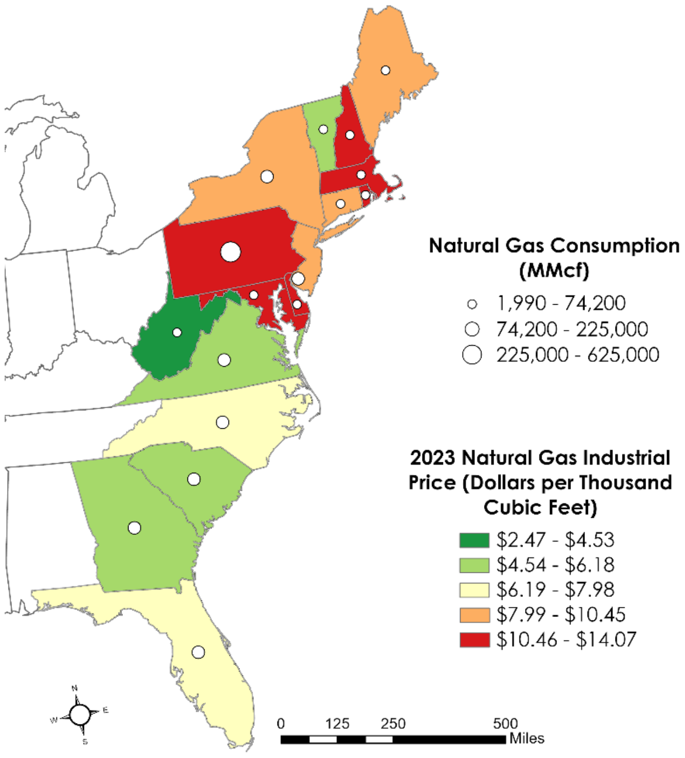

Figure 9. Natural gas consumption and price by state (2023)

Individual sector values were not available in the raw data. Pennsylvania had the largest overall consumption in the region at 261,491 cubic feet, while Rhode Island had the least at around 8,160 cubic feet (in 2023). Interestingly, unlike the Gulf Coast, the East

Coast cost of natural gas appears to have been influenced by some outside factor, as there does not appear to be a logical correlation between price, supply, and consumption. For example, Florida has no natural gas infrastructure to speak of other than pipelines and no wells or market hubs in place (see **Figure 10**).

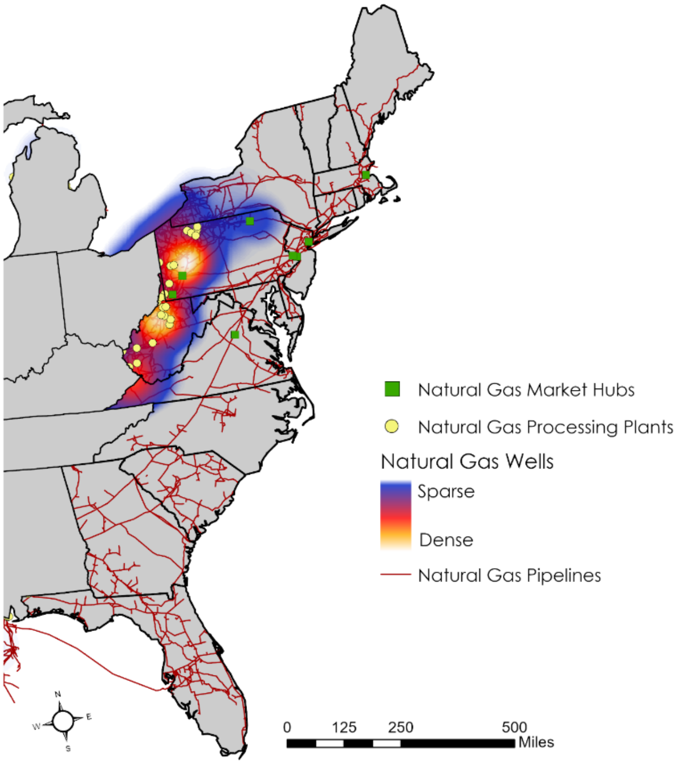

Figure 10. Natural gas infrastructure in the East Coast

Despite this, the price of natural gas sits at a moderate $7/MMBtu compared to the rest of the region, while Pennsylvania, the largest energy state in the region with plentiful natural gas reserves and infrastructure (and convenient geography—near to the equally gas-rich West Virginia and the Midwest states), has prices of over $10/MMBtu. Similarly, the New England states all appear to have similar levels of natural gas demand, and most said states consequently have prices at or above $8/MMBtu, with New Hampshire and Maryland being the most notable at over $10/MMBtu. Vermont stands out as a notable outlier, with natural gas prices falling below $6/MMBtu—despite facing similar supply constraints as neighboring states and being more geographically disadvantaged than Connecticut, New Jersey, and New York. These other states benefit from relatively easier access to inexpensive natural gas from sources like West Virginia. The underlying causes of Vermont's anomalously low prices remain unclear, but potential contributing factors may include state-specific regulations, tax structures, local incentives, transportation and storage challenges not captured in the current dataset—such as difficult terrain or limited infrastructure, including railways, navigable rivers, or sufficiently wide roadways.

Appendix G: Estimated Costs and Emissions

Producing and Delivering Emerging Fuels in Each State

The Hydrogen Delivery Scenario Analysis Model (HDSAM), developed by ANL, was used to determine costs of H_2 transportation and delivery (Elgowainy & Reddi, 2022). Region-specific factors such as electricity prices, natural gas price, and labor costs were incorporated to adjust HDSAM values and estimate state-level data, and all prices are reported in 2023$. Aside from these adjustments, all default assumptions in the HDSAM were maintained. Both liquid and gaseous transportation and delivery options were analyzed (see **Table 13**).

Table 13. Summary of liquid and gaseous delivery costs by state in East Coast

State	Liquid Delivery Transport Cost (2023$/kg H_2)	Gaseous Delivery Transport Cost (2023$/kg H_2)
Connecticut	4.79	3.11
Delaware	3.42	2.86
Florida	3.09	2.25
Georgia	2.47	1.91
Maine	3.76	2.30
Maryland	3.47	2.56
Massachusetts	5.00	3.67
New Hampshire	4.76	2.83

New Jersey	4.56	3.56
New York	3.87	3.23
North Carolina	2.66	1.91
Pennsylvania	3.15	2.53
Rhode Island	5.09	3.62
South Carolina	2.52	1.69
Vermont	3.77	2.10
Virginia	2.88	2.08
West Virginia	2.87	1.78

The liquid option includes an H_2 liquefier at the production facility, a liquid H_2 terminal, and a liquid H_2 delivery truck. The gaseous option includes compression at the production facility, a gaseous H_2 terminal, and transport via tube truck. SNG and RNG projects may have additional pipeline interconnection costs, depending on the location of the plant, existing infrastructure availability, and scale of the project (Lowell & Jones, 2019). For the SNG cases (SNG-1–SNG-4), the plant can be co-located near the CO_2 point source, reducing CO_2 transportation costs and being able to take advantage of existing pipeline infrastructure that already exists near the point source plant. For the MSW to RNG case (RNG-1), pipeline interconnection costs may be lower than other RNG sources due to the proximity of many landfills to existing pipelines. An M.J. Bradley & Associates report states that interconnection costs are a function of project size and can range from $39/MMBtu (in 2023$) for small projects (10 MMBtu/hr) to $13/MMBtu (in 2023$) for medium-sized projects (100 MMBtu/hr) (Lowell & Jones, 2019).

For the biomass to RNG case (RNG-2), the gasification facility may be in proximity to biomass plantations to reduce biomass transportation costs and not near existing pipeline infrastructure, resulting in higher costs for pipeline interconnection. The M.J. Bradley & Associates report stated that costs for dairy RNG, which are typically located in remote locations similar to biomass plantations, range from $10/MMBtu for larger projects to $30/MMBtu for smaller projects, due to pipeline extensions required to connect existing natural gas networks (Lowell & Jones, 2019). Adjusting these values to 2023$ and factoring in the capacity of the RNG-2 case specific to the East Coast results in interconnection costs of $14.5/MMBtu for RNG-2.

End-Use Costs and Emissions of H2 Blends

Power Generation Costs

Hydrogen can be fired in gas turbines to generate electricity without any direct CO_2 emissions. For a back-of-the- envelope estimate, the lower heating value (LHV) of hydrogen, 33.3 kWh/kg (The Engineering ToolBox, 2003), can be used to determine its energy content. Kawasaki Heavy Industries' L30A turbine can achieve 40.3% efficiency (2025) when operating on hydrogen. This results in electricity price estimates of $155.1/MWh for the lowest cost hydrogen scenario in the East Coast (H2-2) and $523.5/MWh for the highest cost hydrogen scenario in the East Coast (H2-8e). These estimates only account for the cost of the hydrogen feedstock. Furthermore, hydrogen-ready turbines typically cost more than conventional natural gas turbines due to design adaptations needed for hydrogen's high diffusivity, low ignition energy, and different combustion dynamics (NETL, 2022). For comparison, the LCOE, adjusted to 2023$ from an NGCC power plant without carbon capture is $51.6/MWh and the LCOE from an NGCC with 95 percent capture is 82.3/MWh (Schmitt, et al., 2022).

Production Emissions

The GHG intensity of the various pathways via LCA was completed following analogous design of those in the main TEA section. The GHG emissions for producing fuels in the various pathways were developed at a state level using the regional-level LCA methodology previously developed and with key parameter changes for upstream natural gas and electricity, which vary by state. All GHG intensity values in this study are on an IPCC AR6 100-year basis.

Table 14 summarizes state-level results for each of the states in the East Coast region. Note that in the case of RNG for the purposes of this report, the two scenarios have been defined differently as compared to the TEA results. The purpose of this is to provide an initial framing of the upper and lower bounds of expected emissions for RNG pathways. Specifically, the RNG pathways for LCA are defined as follows: RNG-1A is defined as representing woody gasification (through thermal) and RNG-1B is defined as sourced from MSW through anaerobic digestion. Likewise, Case H2-8 (which is production with low-carbon electricity) is assumed to be a single pathway that has a mix of low-carbon sources not including nuclear, as detailed in Appendix B: Summary of Detailed LCA Case Assumptions in OHI Toolkit, as Case H2-8). Parallel low-carbon electrolysis scenarios are shown (as in the TEA section) as Case H2-8a–8e as well as Case H2-8a/b, representing only a mix of solar and wind. For the East Coast region, most states show only modest variation in GHG intensity for low-carbon electricity pathways (less than 5%); this may be due to minimal grid mix variation among states in this region. However, it is important to note that the cases that use biomass-generated electricity (H2-8e), the variation across state can go as high as 30%, which likely stems from difference in biogenic carbon accounting and feedstock origin used in state-specific life cycle data. Notably, H2-6 shows slightly negative GHG intensities in some states when grid connected electrolysis draws from very low carbon or surplus renewable electricity, thereby confirming that regional grid decarbonization heavily sways the electrolysis pathways toward being net-beneficial as compared to fossil pathways.

Similarly, SNG pathways display uniform results across region with less than 1% variation across the states, which can be attributed to the process-level assumptions being the dominant factor that often dictate life cycle outcomes. It is also important to note that the current methodology primarily captures variability in electricity and natural gas contributions to the overall GWP. While this approach effectively highlights the influence of energy sources, a more granular analysis could be achieved by developing independent OpenLCA models for each SNG scenario. This would allow upstream inventories to reflect differences in capture technologies, retrofit configurations, and process efficiencies, providing a more detailed understanding of how system-level design choices affect life cycle performance. Such refinement would enhance the sensitivity of the results without altering the overarching trends observed across pathways. This granular parameter control requires a much more sensitive study design and is a more time-intensive process.

For the alternative SNG cases (e.g., SNG-1a–1e), where electrolysis is powered by a single renewable or low-carbon source (solar, wind, nuclear, hydro, biomass), the full OpenLCA model was not rebuilt for each electricity mix due to modeling complexity and time constraints. Instead, this analysis adopted a streamlined approach by isolating the electricity-related GHG contribution from the OpenLCA output and adjusting it externally. This was done by multiplying the electricity demand of electrolysis (assumed to be 5.97 MJ electricity per kg SNG) by literature-based carbon intensities of electricity sources (e.g., 15 gCO_2e/MJ for solar from NREL/Argonne National Laboratory's (ANL) Greenhouse Gases, Regulated emissions, and Energy use in Technologies [GREET], 11 for wind, 12 for nuclear, etc.). These adjusted values were then added back to the non-electricity GHG contributions from the original OpenLCA model to produce total GWP per kg SNG for each electricity source and state.

RNG-1A represents a true waste boundary case, which begins at the receipt of forest thinning at the production facility. All upstream biomass production and carbon uptake is excluded (Henriksen et al., Release Forthcoming). This is consistent with the International Organization for Standardization (ISO) 14040/14044—compliant attributional modeling practices for waste feedstocks—where CO_2 uptake is only credited if the system includes biomass production. Therefore, no avoided emissions are credited, and no displacement of fossil natural gas or upstream sequestration benefits are included. This is aligned with ISO 14067 guidance, which warns against mixing consequential assumptions (e.g., displacement or avoided emissions) with attributional frameworks unless fully justified and documented. Including credits for avoided fossil gas combustion or downstream use would introduce methodological inconsistencies and is not supported in most ISO-compliant LCAs unless using consequential modeling (which this study does not adopt). Additionally, CO_2 uptake from biomass is only considered in the expanded system, shown in Case RNG-1B. In the true waste case, biogenic CO_2 is neither assigned a GWP of zero nor a negative value—it is excluded entirely, in line with attributional principles for end-of-life residues. Assigning a GWP of zero across the board for biogenic CO_2 without tracking fate or residence time would conflict with AR6 guidance and is explicitly avoided in this model.

Table 14. State-level fuel carbon intensity results for the East Coast region

Case	D.C.	CT	DE	FL	GA	ME	MD	MA	NH	NJ	NY	NC	PA	RI	SC	VT	VA	WV
Low-Carbon H_2 (kg CO_2e/kg H_2)																		
H2-1	2.51	2.39	2.51	2.56	2.55	2.39	2.51	2.39	2.39	2.51	2.37	2.36	2.51	2.39	2.33	2.39	2.51	2.51
H2-2	1.58	1.43	1.58	1.78	1.73	1.11	1.58	1.11	1.11	1.58	1.02	0.98	1.58	1.11	0.87	1.11	1.58	1.58
H2-3	8.55	8.55	8.55	8.55	8.55	8.55	8.55	8.55	8.55	8.55	8.55	8.55	8.55	8.55	8.55	8.55	8.55	8.55
H2-4	8.98	8.60	8.98	9.14	9.10	8.60	8.98	8.60	8.60	8.98	8.53	8.50	8.98	8.60	8.41	8.60	8.98	8.98
H2-5	1.45	1.33	1.45	1.49	1.48	1.33	1.45	1.33	1.33	1.45	1.31	1.30	1.45	1.33	1.27	1.33	1.45	1.45
H2-6	0.58	0.11	0.58	0.78	0.73	0.11	0.58	0.11	0.11	0.58	0.02	-0.02	0.58	0.11	-0.13	0.11	0.58	0.58
H2-7	5.16	5.16	5.16	5.16	5.16	5.16	5.16	5.16	5.16	5.16	5.15	5.15	5.16	5.16	5.15	5.16	5.16	5.16
H2-8	3.39	3.38	3.39	3.44	3.43	3.38	3.39	3.38	3.38	3.39	3.38	3.37	3.39	3.38	3.36	3.38	3.39	3.39
H2-8a	2.37	2.14	2.37	2.47	2.44	2.14	2.37	2.14	2.14	2.37	2.10	2.08	2.37	2.14	2.02	2.14	2.52	2.37
H2-8b	2.19	2.14	2.19	2.22	2.21	2.14	2.19	2.14	2.14	2.19	2.12	2.12	2.19	2.14	2.11	2.14	2.19	2.19
H2-8c	1.47	1.43	1.47	1.48	1.48	1.43	1.47	1.43	1.43	1.47	1.43	1.42	1.47	1.43	1.42	1.43	1.47	1.47
H2-8d	0.82	0.82	0.82	0.83	0.83	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82	0.82

Case	D.C.	CT	DE	FL	GA	ME	MD	MA	NH	NJ	NY	NC	PA	RI	SC	VT	VA	WV
H2-8e	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41	3.41
H2-8 (a/b)	2.28	2.14	2.28	2.34	2.33	2.14	2.28	2.14	2.14	2.28	2.11	2.10	2.28	2.14	2.06	2.14	2.28	2.28
SNG (kg CO_2e/kg SNG)																		
SNG-1	17.03	16.90	17.03	17.10	17.12	16.90	17.03	16.90	16.90	17.03	16.85	16.85	17.03	16.90	16.85	16.90	17.03	17.03
SNG-1a	16.53	16.96	16.50	16.52	16.52	16.49	16.50	16.55	16.49	16.50	16.49	16.53	16.49	16.51	16.50	16.49	16.51	16.49
SNG-1b	16.49	16.96	16.49	16.49	16.49	16.53	16.49	16.49	16.49	16.49	16.50	16.49	16.49	16.50	16.49	16.49	16.49	16.55
SNG-1c	16.49	17.10	16.49	16.56	16.64	16.62	16.65	16.49	16.60	16.64	16.57	16.64	16.64	16.49	16.72	16.49	16.62	16.49
SNG-1d	16.49	16.97	16.49	16.49	16.50	16.49	16.51	16.52	16.51	16.49	16.57	16.50	16.49	16.49	16.50	16.51	16.49	16.53
SNG-1e	16.59	16.97	16.49	16.49	16.51	16.50	16.49	16.52	16.50	16.49	16.49	16.49	16.49	16.50	16.49	16.49	16.50	16.49
SNG-1 (a+b)	16.51	16.97	16.50	16.50	16.50	16.51	16.49	16.52	16.49	16.49	16.50	16.51	16.49	16.51	16.49	16.49	16.50	16.52
SNG-2	14.28	14.15	14.28	14.35	14.37	14.15	14.28	14.15	14.15	14.28	14.10	14.10	14.28	14.15	14.10	14.15	14.28	14.28
SNG-2a	13.78	13.74	13.75	13.77	13.77	13.74	13.75	13.80	13.74	13.75	13.74	13.78	13.74	13.76	13.75	13.74	13.76	13.74
SNG-2b	13.74	13.74	13.74	13.74	13.74	13.78	13.74	13.74	13.74	13.74	13.75	13.74	13.74	13.75	13.74	13.74	13.74	13.80
SNG-2c	13.74	13.87	13.74	13.81	13.89	13.87	13.90	13.74	13.85	13.89	13.82	13.89	13.89	13.74	13.97	13.74	13.87	13.74

Case	D.C.	CT	DE	FL	GA	ME	MD	MA	NH	NJ	NY	NC	PA	RI	SC	VT	VA	WV
SNG-2d	13.74	13.74	13.74	13.74	13.75	13.74	13.76	13.77	13.76	13.74	13.82	13.75	13.74	13.74	13.75	13.76	13.74	13.78
SNG-2e	13.84	13.74	13.74	13.74	13.76	13.75	13.74	13.76	13.75	13.74	13.74	13.74	13.74	13.75	13.74	13.74	13.75	13.74
SNG-2 (a+b)	13.76	13.74	13.75	13.75	13.75	13.76	13.74	13.77	13.74	13.74	13.75	13.76	13.74	13.75	13.74	13.74	13.75	13.77
SNG-3	19.59	19.46	19.59	19.66	19.69	19.46	19.59	19.46	19.46	19.59	19.41	19.42	19.59	19.46	19.42	19.46	19.59	19.59
SNG-3a	19.10	19.05	19.07	19.09	19.08	19.06	19.06	19.11	19.05	19.06	19.06	19.10	19.05	19.08	19.06	19.06	19.08	19.05
SNG-3b	19.05	19.05	19.05	19.05	19.05	19.09	19.06	19.06	19.06	19.05	19.07	19.05	19.06	19.06	19.05	19.06	19.05	19.11
SNG-3c	19.05	19.19	19.05	19.13	19.21	19.19	19.22	19.05	19.17	19.21	19.14	19.21	19.21	19.05	19.28	19.05	19.18	19.05
SNG-3d	19.05	19.06	19.05	19.05	19.06	19.06	19.07	19.0 9	19.07	19.05	19.14	19.07	19.06	19.05	19.06	19.08	19.06	19.10
SNG-3e	19.15	19.06	19.06	19.06	19.07	19.06	19.06	19.08	19.06	19.06	19.06	19.06	19.06	19.07	19.06	19.06	19.07	19.05
SNG-3 (a+b)	19.07	19.06	19.06	19.07	19.07	19.08	19.06	19.09	19.06	19.06	19.06	19.08	19.06	19.07	19.06	19.06	19.06	19.08
SNG-4	14.43	14.30	14.43	14.50	14.53	14.30	14.43	14.30	14.30	14.43	14.25	14.26	14.43	14.30	14.26	14.30	14.43	14.43
SNG-4a	13.93	13.89	13.91	13.92	13.92	13.90	13.90	13.95	13.89	13.90	13.90	13.93	13.89	13.92	13.90	13.89	13.91	13.89
SNG-4b	13.89	13.89	13.89	13.89	13.89	13.93	13.90	13.90	13.90	13.89	13.90	13.89	13.90	13.90	13.89	13.90	13.89	13.95
SNG-4c	13.89	14.03	13.89	13.96	14.05	14.03	14.05	13.89	14.01	14.05	13.97	14.05	14.04	13.89	14.12	13.89	14.02	13.89

Case	D.C.	CT	DE	FL	GA	ME	MD	MA	NH	NJ	NY	NC	PA	RI	SC	VT	VA	WV
SNG-4d	13.89	13.89	13.89	13.89	13.90	13.90	13.91	13.93	13.91	13.89	13.98	13.91	13.90	13.89	13.90	13.91	13.89	13.93
SNG-4e	13.99	13.90	13.90	13.90	13.91	13.90	13.89	13.92	13.90	13.89	13.90	13.90	13.89	13.90	13.90	13.90	13.90	13.89
SNG-4(a+b)	13.91	13.89	13.90	13.91	13.91	13.91	13.90	13.92	13.89	13.89	13.90	13.91	13.89	13.91	13.90	13.89	13.90	13.92
RNG (kg CO_2e/kg RNG)																		
RNG-1A	11.77	11.77	11.77	11.77	11.77	11.77	11.77	11.77	11.77	11.77	11.76	11.76	11.77	11.77	11.76	11.77	11.77	11.77
RNG-1B	-0.35	-0.40	-0.35	-0.33	-0.32	-0.40	-0.35	-0.40	-0.40	-0.35	-0.42	-0.42	-0.35	-0.40	-0.42	-0.40	-0.35	-0.35

Appendix H: NEMS Results Summary

Emissions

The figure below shows the emissions (y-axis) by year (x-axis) for each scenario run (each vertical bar on x-axis), and sector (size of colored vertical bar on y-axis). In general, total emissions in all scenarios decrease over time, but the effect is much smaller in the AEO23 and HM-HZTC cases and the largest in the Low OGS case. Total emissions in 2050 are lowest in the Low OGS case, resulting from lower energy availability and, therefore, macroeconomic growth. In the LowC H2 and RNG cases, 20% blending cases have lower total emissions than 5% blending cases but in the SNG 20% case the increase in power emissions outweighs the decrease in other sectors (see **Figure 11**).

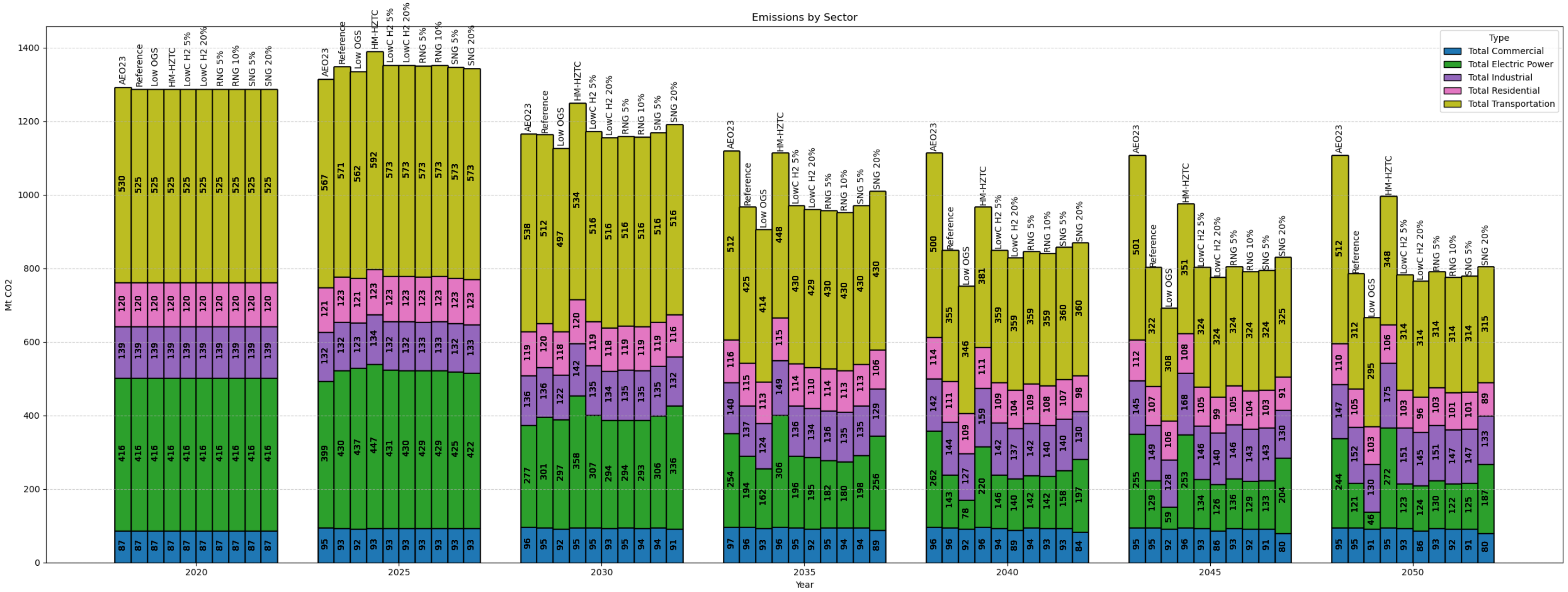

Figure 11. Emissions by sector

Power Sector

Generation

The figure below shows the power generation (y-axis) by year (x-axis) for each scenario run (each vertical bar on x-axis), and technology type (size of colored vertical bar on y-axis). Overall, all scenarios show a decline in generation from coal and an increase in generation from renewables. In all cases except the AEO23, power generation from coal is nearly zero by 2050. The generation increases in the SNG 5% case and dramatically so in the SNG 20% cases, with the latter showing increases across renewable and gas technologies (see **Figure 12**).

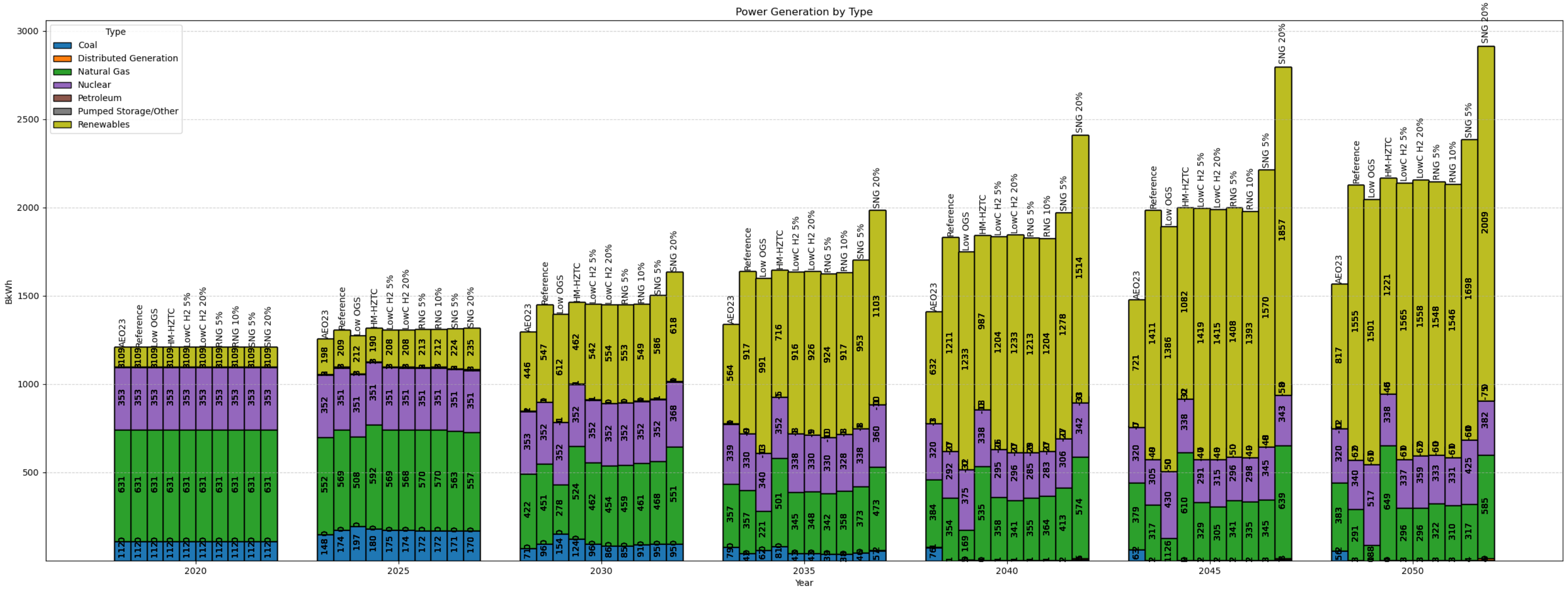

Figure 12. Power generation by type

Capacity

Power capacity shows similar trends to power generation. The figure below shows the capacity (y-axis) by year (x-axis) for each scenario run (each vertical bar on x-axis), and technology type (size of colored vertical bar on y-axis). Overall the capacity increases to meet demand each year till 2050 in all cases, however the scenarios with increased renewable capacity add more capacity overall due to the intermittent nature of renewables. In all cases except the AEO23, coal power capacity is nearly zero by 2050. The capacity increases in the SNG 5% case and dramatically so in the SNG 20% cases, with the latter showing increases across gas combined cycle and renewable technologies (see **Figure 13**).

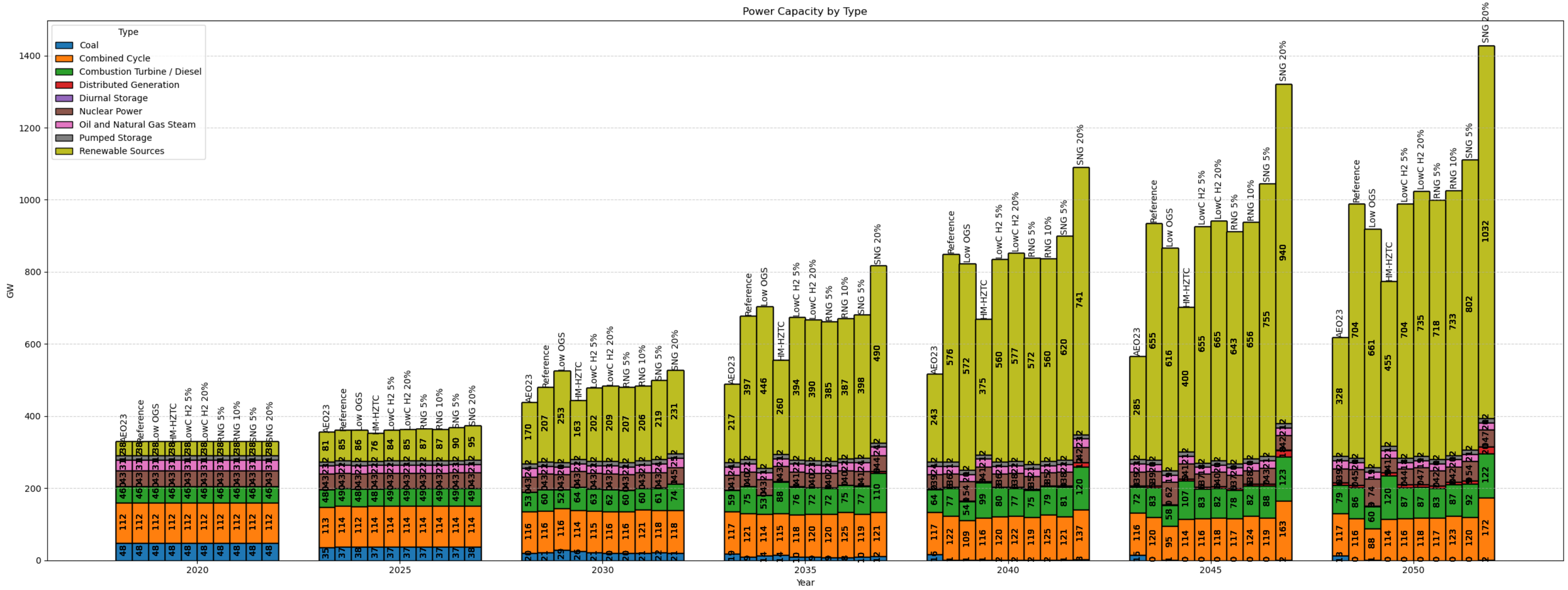

Figure 13. Power capacity by type

Utilizing East Coast Natural Gas Infrastructure for Emerging Fuels – Appendix

Sales

The figure below shows the power sales (y-axis) by year (x-axis) for each scenario run (each vertical bar on x-axis), and sector (size of colored vertical bar on y-axis). Overall power demand increases every year till 2050 in all cases. However, power sales to H2 and industry increase in the SNG 5% case and dramatically so in the SNG 20% cases. This is due to the constraint on producing H2 for SNG production primarily via electrolysis (see **Figure 14**). Sales to the commercial sector in AEO23 are lower than all the other cases due to the adjustment for data center demand present in OL-NEMS scenarios.

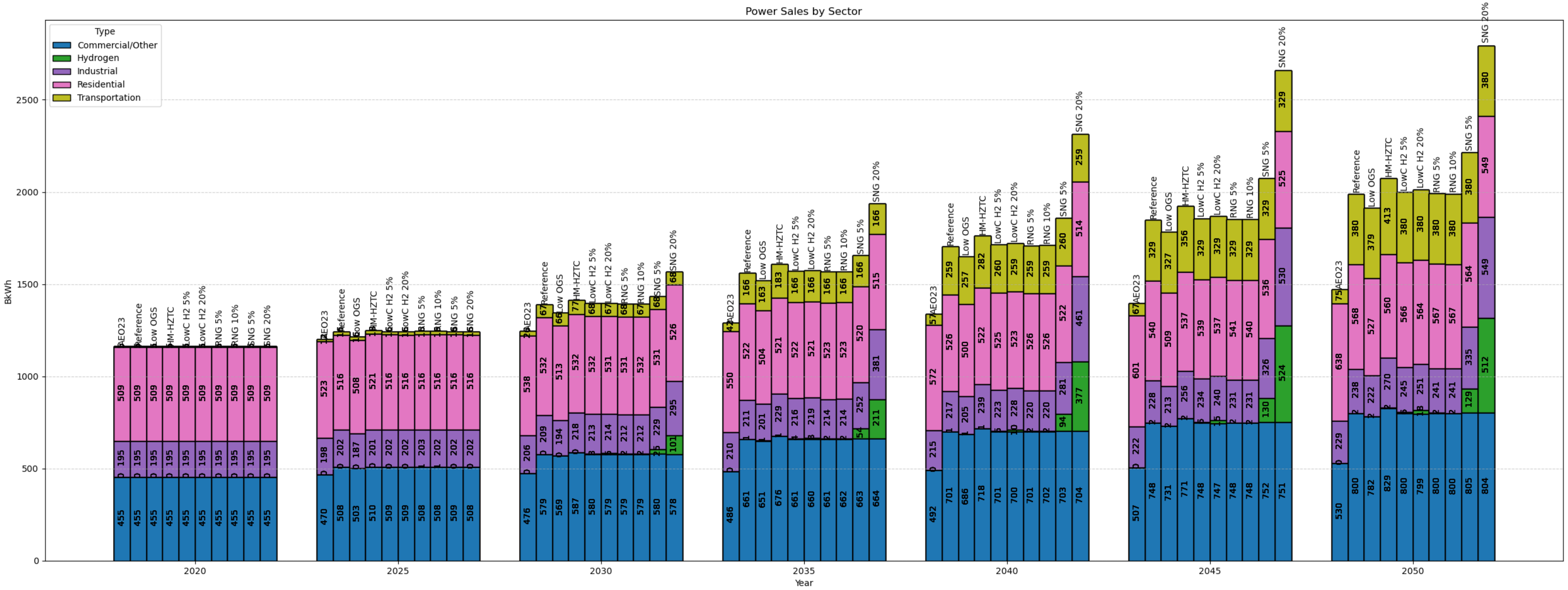

Figure 14. Power sales by sector

Prices

The figures below show the power prices (y-axis) by year (x-axis) for each scenario run (each line), and sector (each figure). In all cases, the power price falls in the initial years through 2035 and then increases after 2040. This is broadly in line with the price of natural gas over those years. Due to the constraint on producing H2 for SNG production primarily via electrolysis in the SNG cases, the power price is higher in those cases (see **Figure 15**).

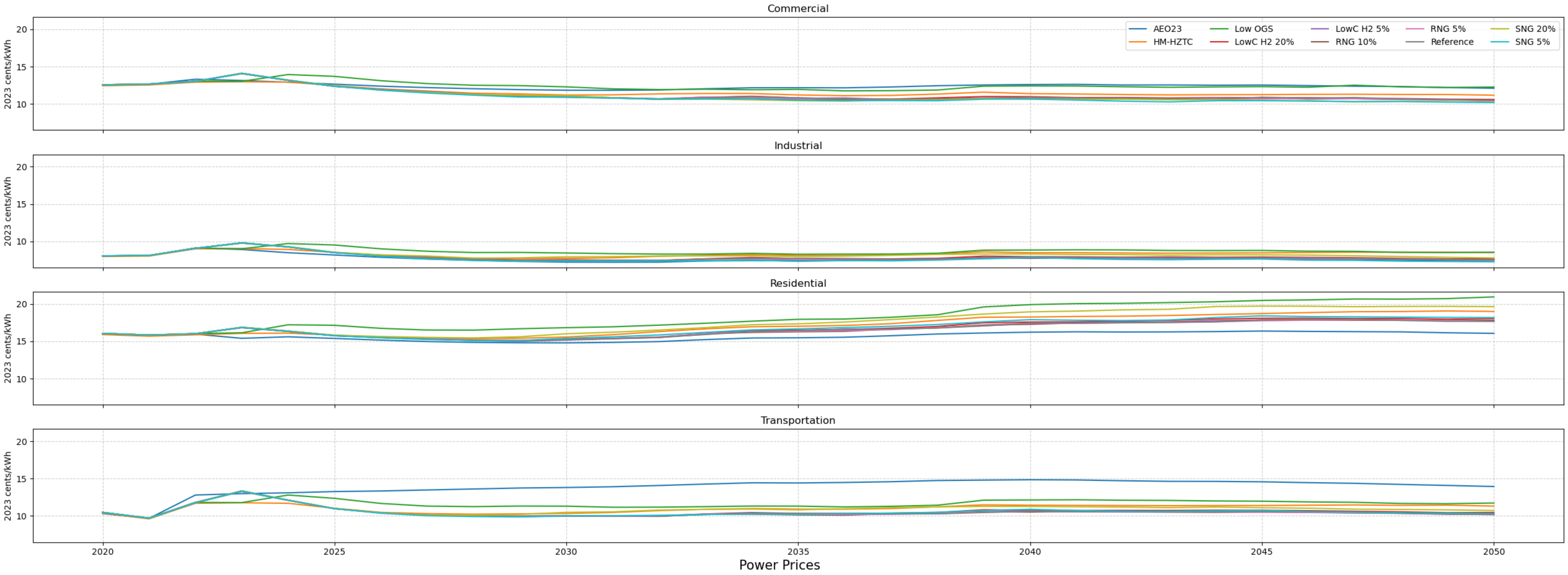

Figure 15. Power prices

Natural Gas

Henry Hub Prices

The figure below shows the Henry Hub natural gas prices (y-axis) by year (x-axis) for each scenario run (each line). In all the scenarios, the price fall in the initial years through 2030 and then rise till 2040. After 2040, most cases except the BAU side cases and the LowC H2 20% case show a decline in prices. Except for the Low OGS case, which results in higher spot prices at the Henry Hub, the other scenarios have consistent trends. The LowC H2 20% case has slightly high prices in later years due to increased NG demand in the power sector (see **Figure 16**).

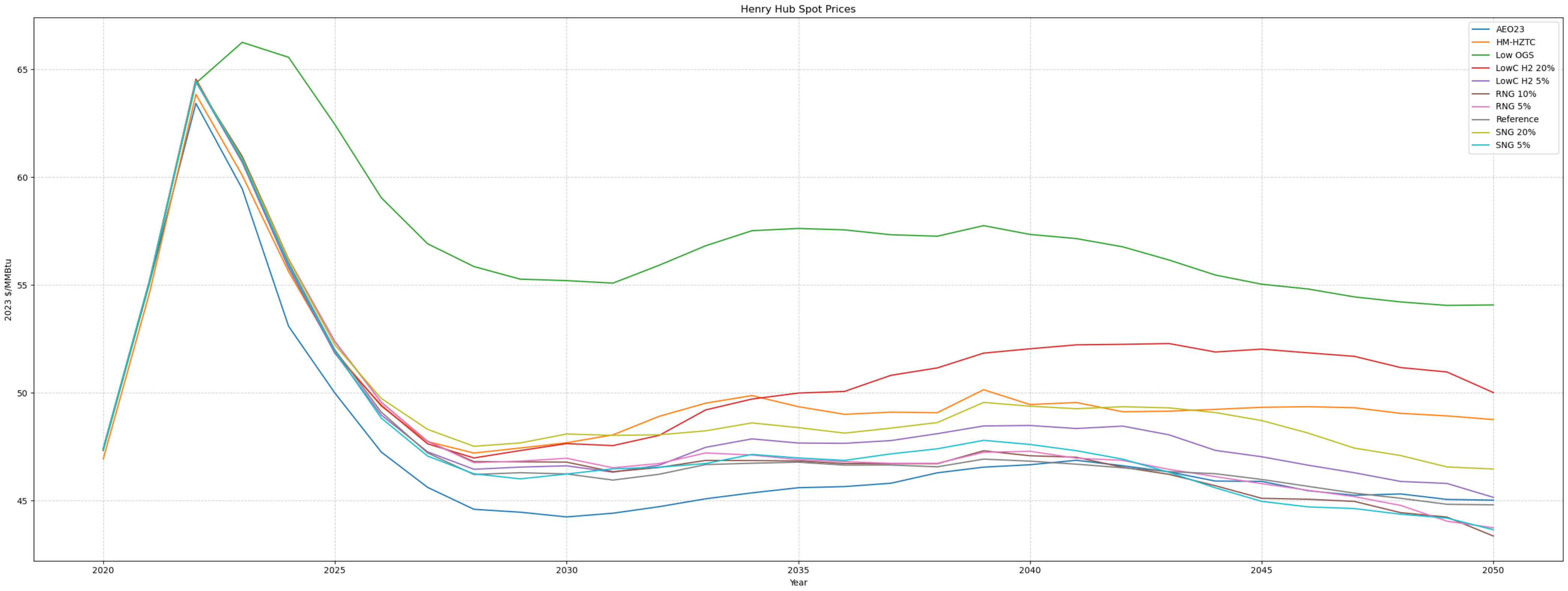

Figure 16. Henry Hub spot prices

Delivered Prices

The figures below show the delivered natural gas prices (y-axis) by year (x-axis) for each scenario run (each line), and sector (each figure). Overall the prices trend lower in all scenarios in the power and transportation sectors, and are stable or rising slightly in the commercial, industrial and residential sectors. Similar to the spot prices, except for the Low OGS case, which results in delivered NG prices, the other scenarios have consistent prices. The LowC H2 20% case has slightly high prices in later years due to increased NG demand in the power sector (see **Figure 17**).

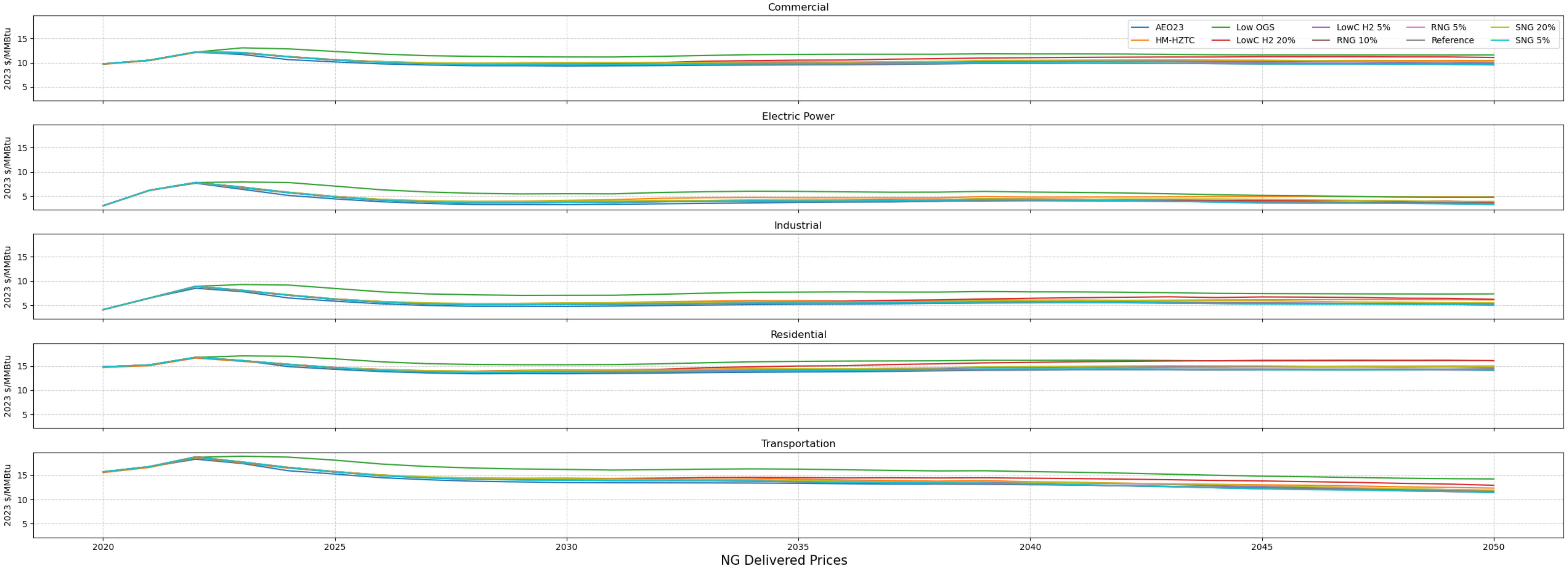

Figure 17. NG delivered prices

LNG Exports

LNG exports from the East Coast are quite low in comparison with the Gulf Coast; therefore, not much change is seen across scenarios for the East Coast (see **Figure 18**).

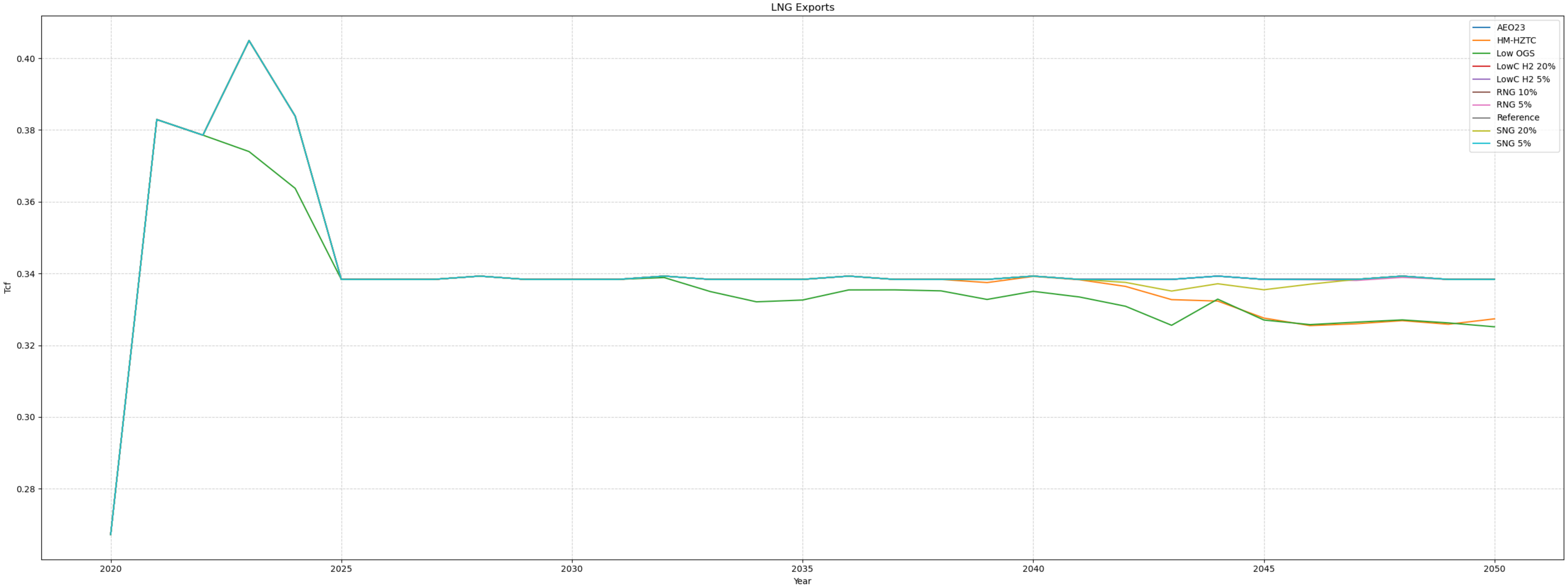

Figure 18. LNG exports

Consumption

The figure below shows the blended natural gas consumption (y-axis) by year (x-axis) for each scenario run (each vertical bar on x-axis), and sector (size of colored vertical bar on y-axis). In all the scenarios the natural gas consumption declines in the early years but less so in the HM-HZTC and SNG 20% cases. These two cases end up with a net increase in consumption by 2050. The total blended NG consumption is lowest in the Low OGS case, while the highest levels are seen in the HM-HZTC and SNG cases, particularly in the power sector. In the LowC H2 cases, high demand from the H2 sector is compensated by lower demand in the industrial sector due to displacement of NG as fuel in industry by H2 (see **Figure 19**).

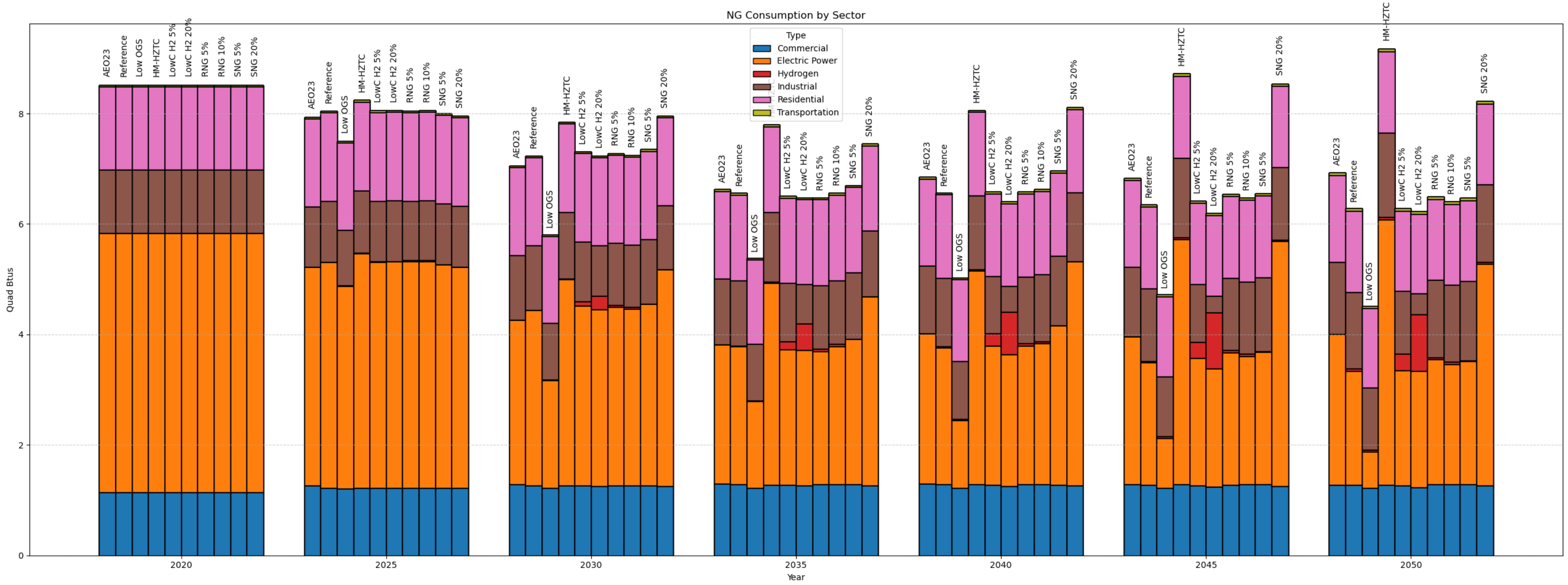

Figure 19. NG consumption by sector

Production

The figure below shows the natural gas production (y-axis) by year (x-axis) for each scenario run (each vertical bar on x-axis), and production type (size of colored vertical bar on y-axis). Production from shale gas dominates in all scenarios and is the highest in the HM-HZTC case. Conventional production declines slightly in all cases while shale production increases in all but the Low OGS case. There is not much tight gas production in the East Coast region currently, and it declines in all cases as well (see **Figure 20**).

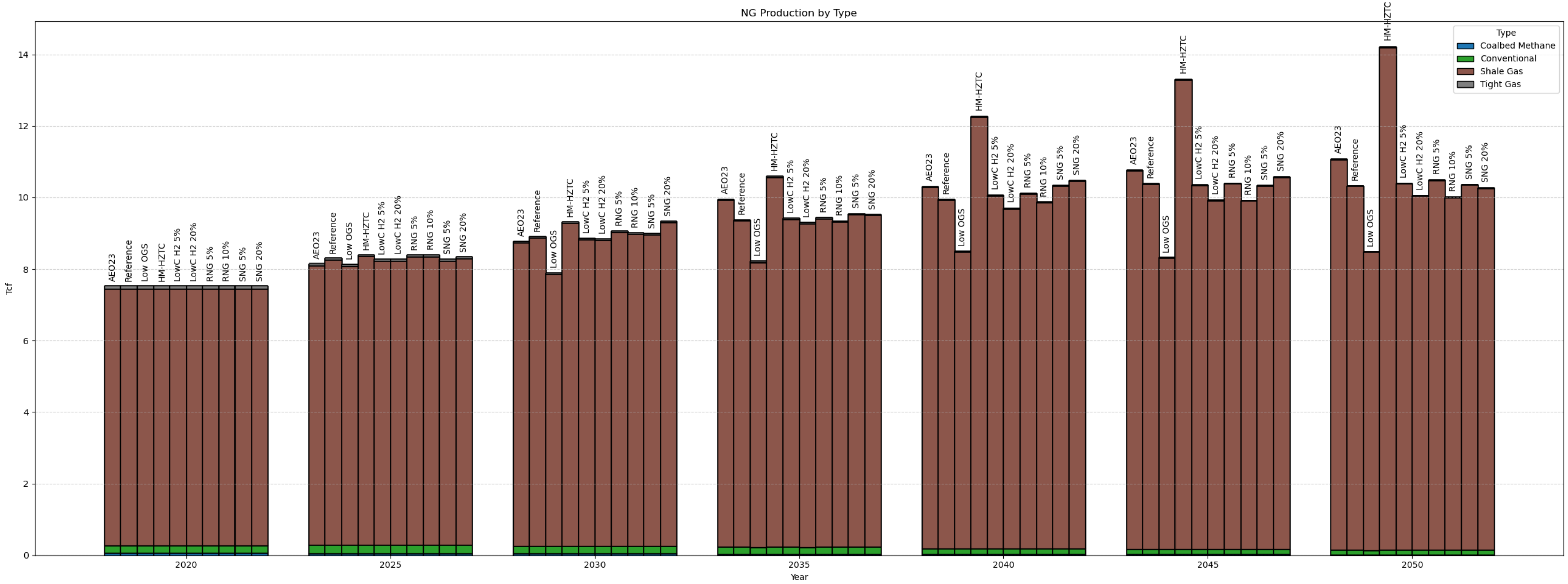

Figure 20. NG production by type

H2 Production

The figure below shows the H_2 production (y-axis) by year (x-axis) for each scenario run (each vertical bar on x-axis), and technology type (size of colored vertical bar on y-axis). In the LowC H_2 cases, the production is mainly from SMR/ATR with CCS and, in the SNG cases, it is from proton exchange membrane electrolysis. There is virtually no production in the other cases. Production from RNG technologies is also zero in all cases due to the high cost of RNG compared to NG and electrolysis (see **Figure 21**).

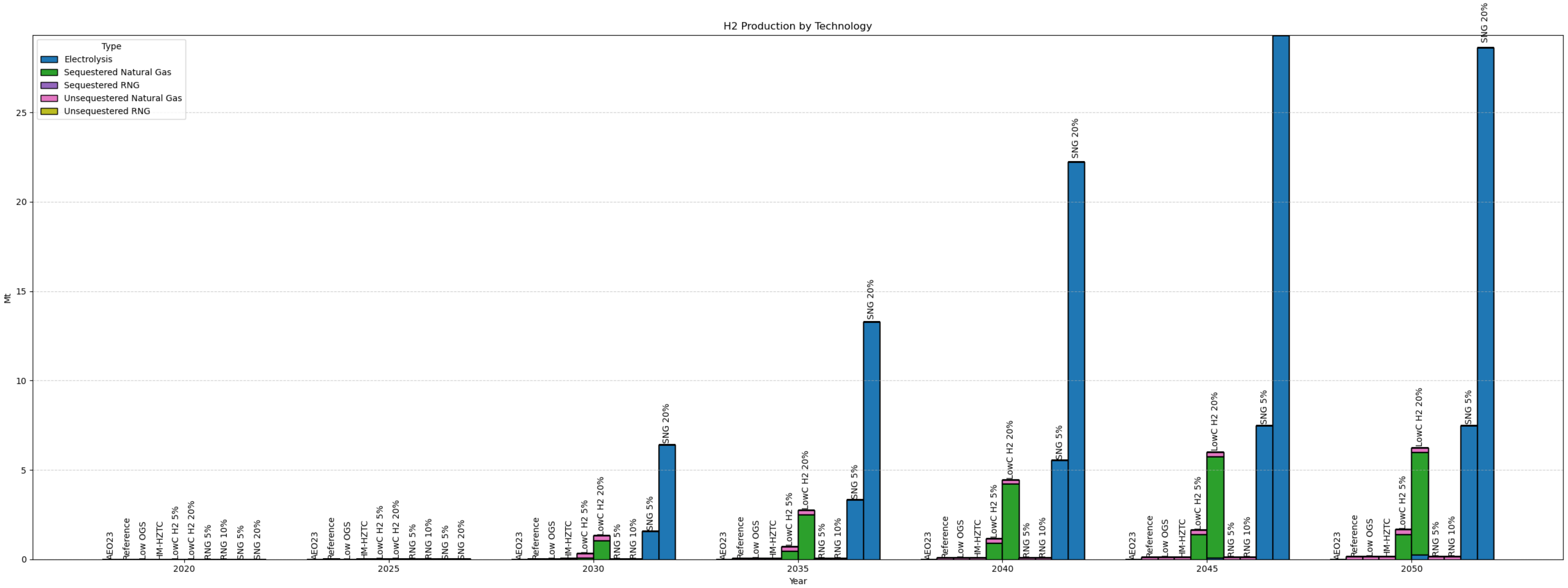

Figure 21. H_2 production by technology

Demand

The figure below shows the H_2 demand (y-axis) by year (x-axis) for each scenario run (each vertical bar on x-axis), and sector (size of colored vertical bar on y-axis). H_2 demand increases dramatically in the LowC H_2 blending and SNG blending cases, the latter due to demand for H_2 in SNG production. There is virtually no demand in the other cases (see **Figure 22**).

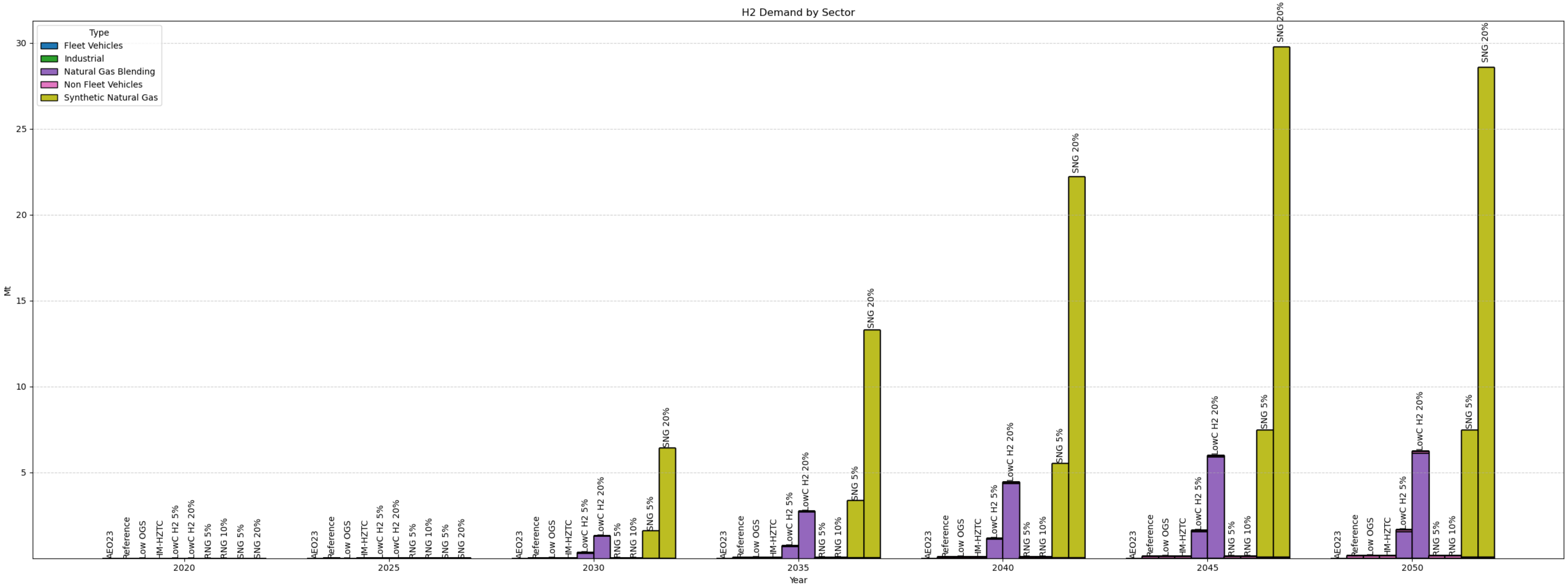

Figure 22. H_2 demand by sector

Prices

The figures below show the H_2 prices (y-axis) by year (x-axis) for each scenario run (each line), and sector (each figure). Except the LowC H_2 and SNG scenarios, prices are stable across all years. But H_2 prices are highest in the Low C H_2 cases in the early years and SNG cases in later years. There is not much difference in the delivered price to different sectors except for the adder to the transportation sector (see **Figure 23**). Note that these prices already include the impact of IRA 45Q credits for SMR with CCS, and 45V credits for electrolyzers.

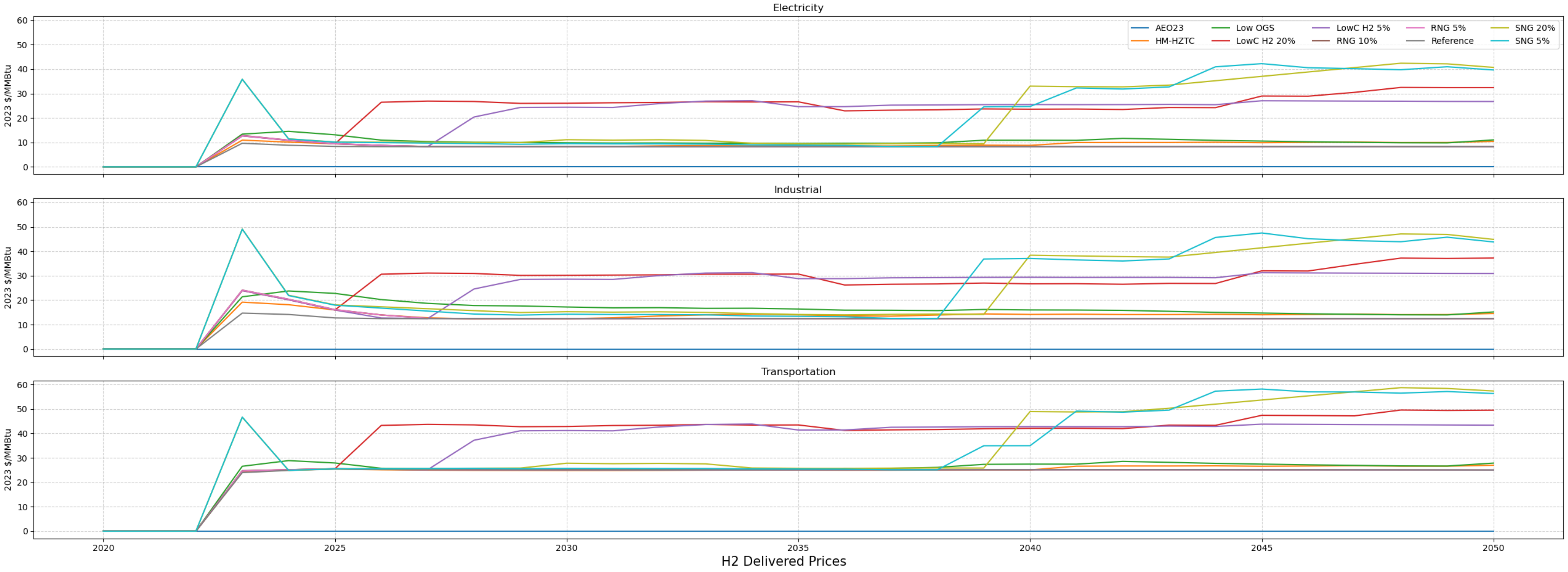

Figure 23. H_2 delivered prices

RNG/SNG Prices

RNG Production

The figure below shows the RNG production (y-axis) by year (x-axis) for the RNG blending scenarios (each line). RNG production is only present in the RNG blending cases and scales with the percentage of blending. No H2 is produced from RNG in any cases (see **Figure 24**).

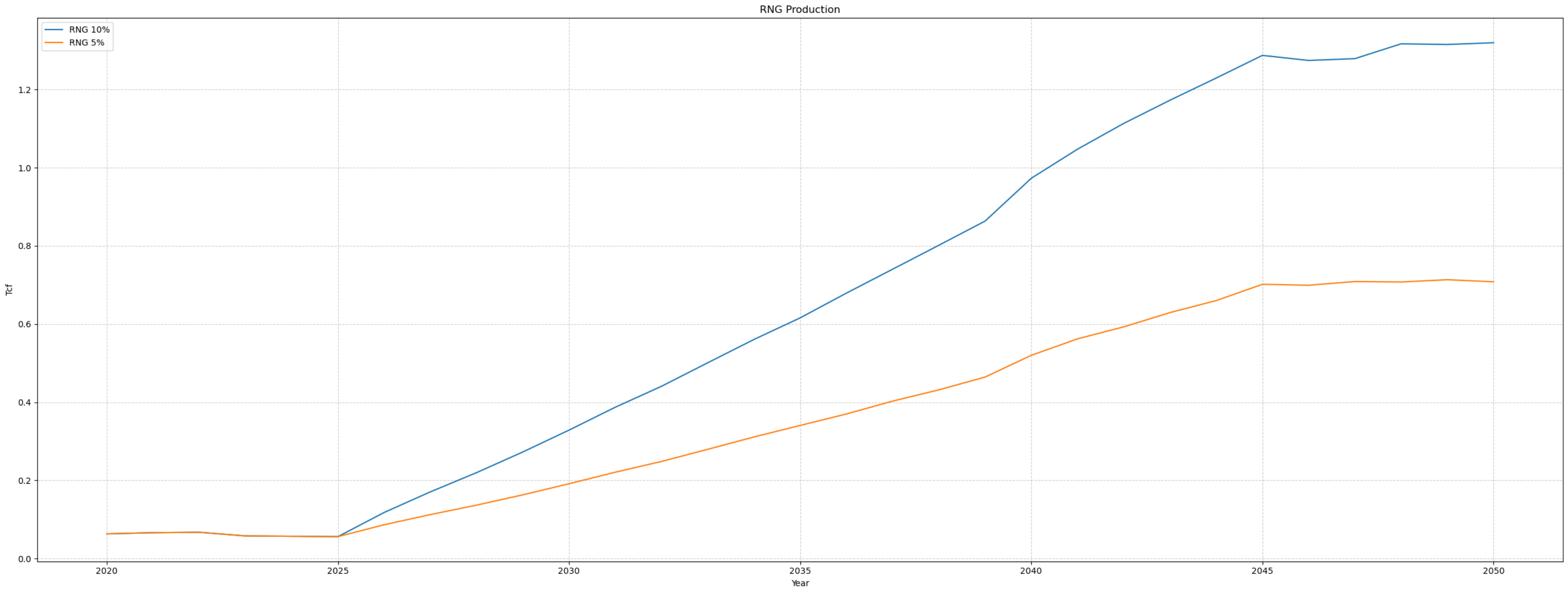

Figure 24. RNG production

RNG Delivered Prices

The figure below shows the RNG prices (y-axis) by year (x-axis) for the RNG blending scenarios (each line). In both scenarios prices trend slightly upwards in early years and then rise somewhat in later years. RNG prices are lower when the new sources from animal manure and water resource recovery are included. These prices are still higher than other competing technologies for H2 production (see **Figure 25**).

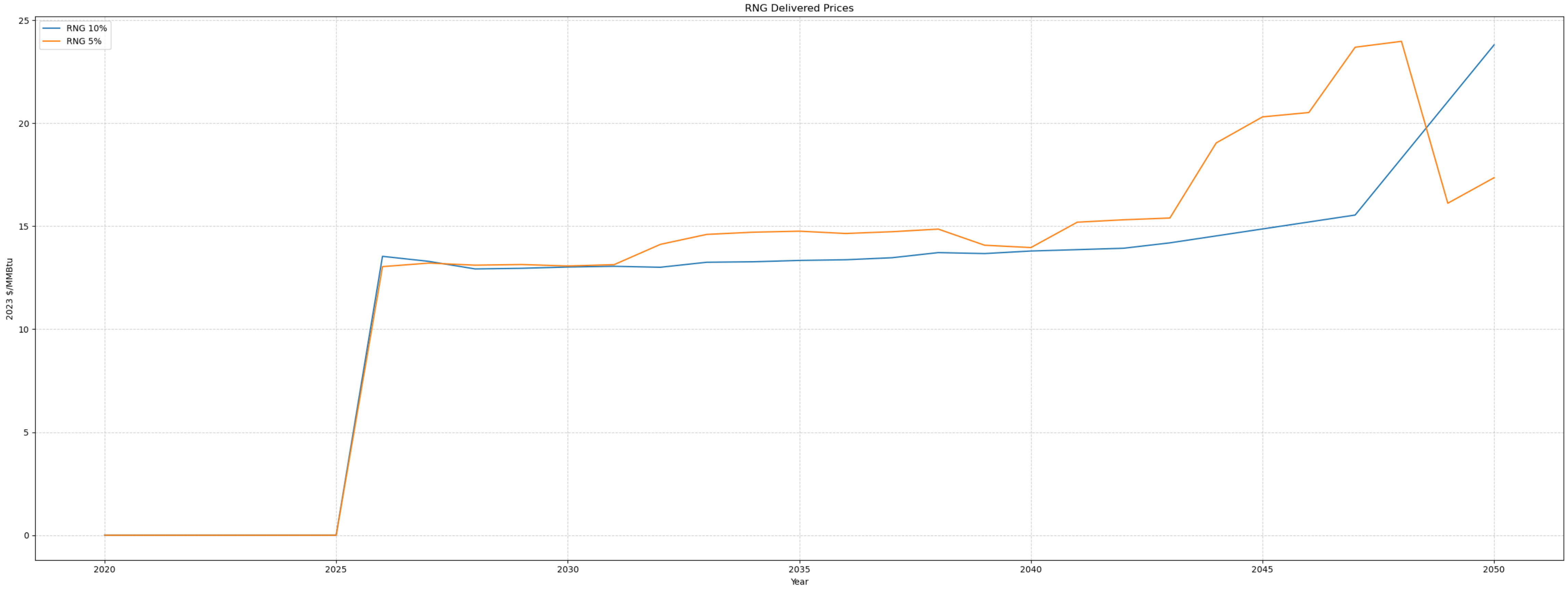

Figure 25. RNG delivered prices

SNG Production

The figure below shows the SNG production (y-axis) by year (x-axis) for SNG blending scenarios (each line). SNG production is only present in the SNG blending cases and scales with the percentage of blending. In the 20% blending case, additional SNG is needed due to higher overall demand for NG in the power sector (see **Figure 26**).

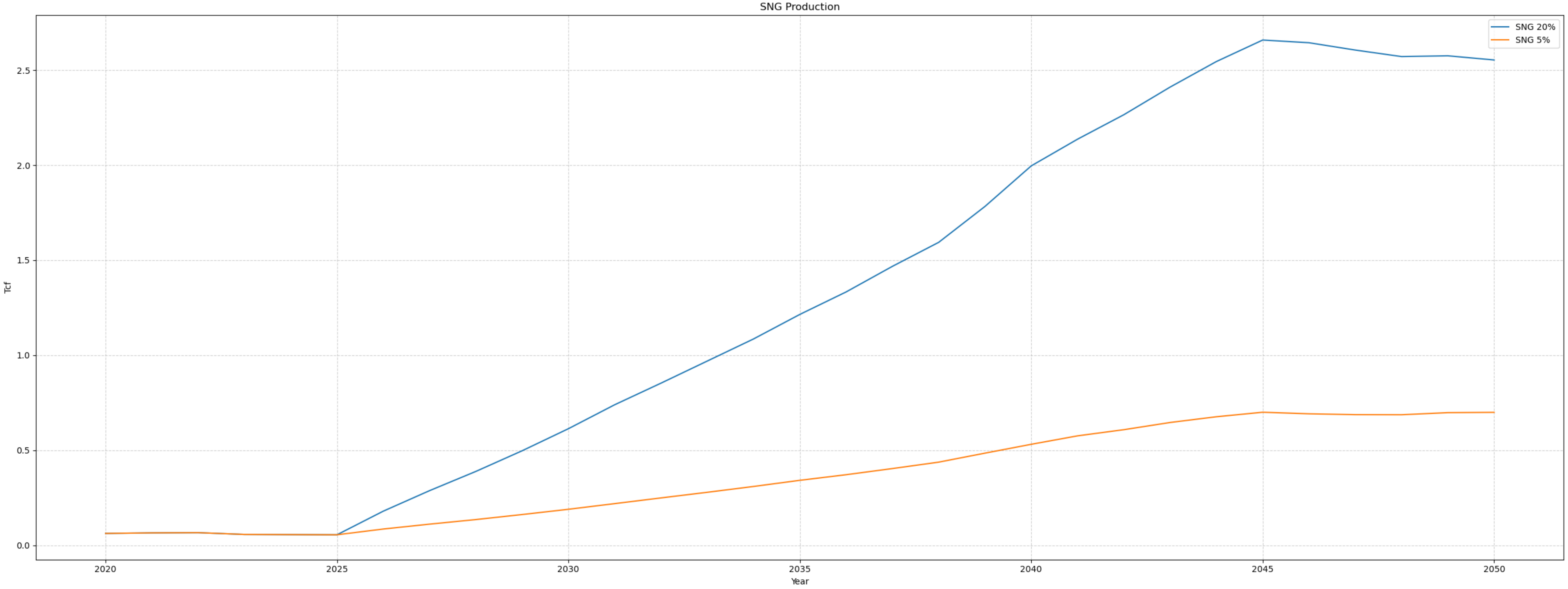

Figure 26. SNG production

SNG Delivered Prices

The figure below shows the SNG prices (y-axis) by year (x-axis) for the SNG blending scenarios (each line). In both scenarios prices trend slightly upwards in early years and then rise substantially in later years. SNG prices scale rapidly with increased blending due to higher costs of H2 from electrolysis, CO2 capture costs from increasingly expensive point sources, and related CO2 transport costs (see **Figure 27**). A jump in prices is seen around 2039 due to the IRA 45Q credits not being available for new retrofits and facilities with CCS after 2038.

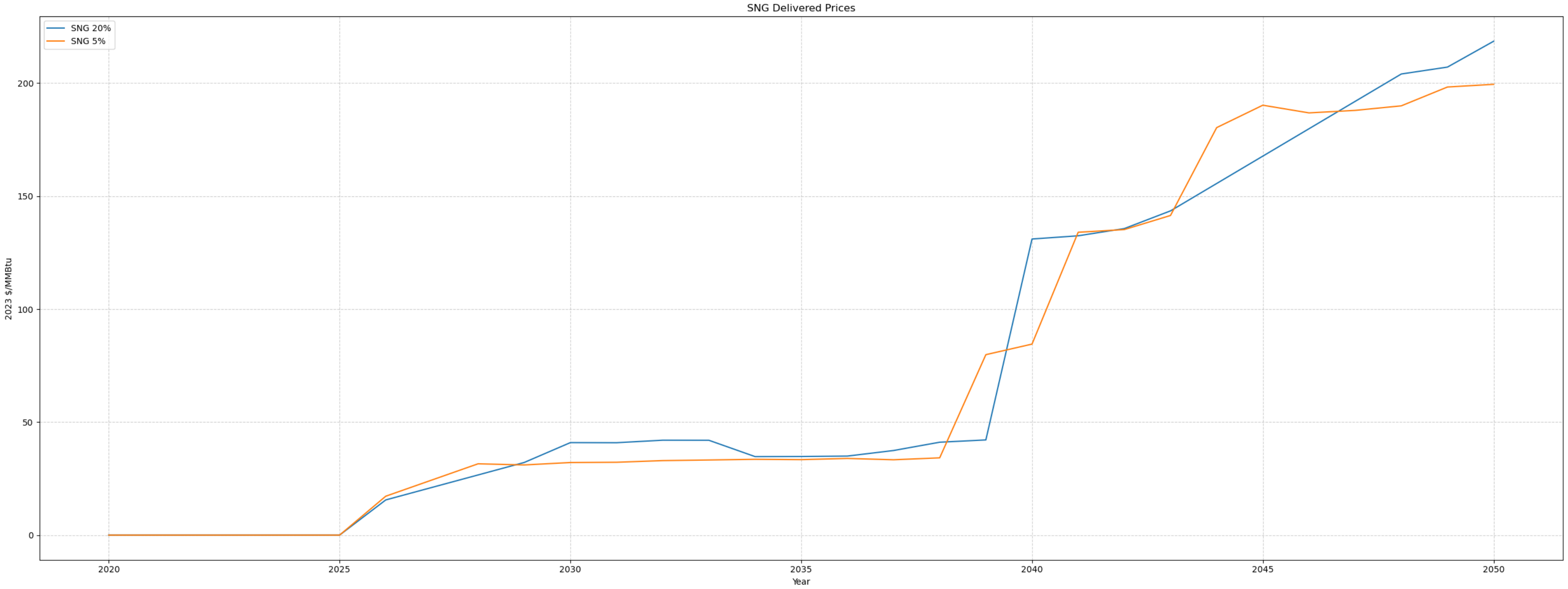

Figure 27. SNG delivered prices