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# Meeting Data Center Electricity Demand

## Mapping carbon capture potential for natural gas-fired generators in the US and Canada

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Nicki Stuckert, Patti Smith,
Daniel Garcia, Jordan Alford

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## Acronyms and abbreviations

**BESS**: Battery energy storage systems
**CC**: carbon capture
**CCS:** carbon capture and storage
**CCU**: carbon capture and utilization
**CCUS**: carbon capture, utilization, and storage
**CI**: carbon intensity
**$CO_2$:** carbon dioxide
**DAC**: direct air capture
**DOE**: Department of Energy (United States)
**EACI**: ELCC-adjusted carbon intensities
**ELCC**: effective load carrying capacity
**EGR**: enhanced gas recovery
**EOR**: enhanced oil recovery
**EPA**: Environmental Protection Agency (United States)
**EU**: European Union
**FERC**: Federal Energy Regulatory Commission
**GHG**: greenhouse gas
**GHGRP**: Greenhouse Gas Reporting Program
**GW**: gigawatts
**HRSG**: Heat recovery steam generation
**IEA**: International Energy Agency
**IIJA**: Infrastructure Investment and Jobs Act
**IRA**: Inflation Reduction Act
**ISO**: independent system operators
**ITC**: Investment tax credit
**LCA**: life cycle assessment
**LCI**: life cycle inventory
**LCOE**: levelized cost of electricity
**MWh**: megawatt hour
**NETL**: National Energy Technology Laboratory
**NG+CCS**: natural gas-fired generation with carbon capture and storage
**NG+CCUS**: natural gas-fired generation with carbon capture, utilization, and storage
**NGCC**: natural gas combined cycle
**NGT**: natural gas turbine
**OBPS**: Output-Based Pricing System (Canada)
**PPA**: power purchase agreements
**RRI**: Reliability Resource Initiative
**RTO**: regional transmission entities
**TWh**: terrawatt hour
**UIC**: underground injection control
**UK**: United Kingdom

## Executive summary

By 2030, data centers are projected to grow demand for electricity by approximately 200 terrawatt hours (TWh).[1] Due to reliability concerns around renewable power sources, a portion of this demand is likely to be filled by more traditional power sources. Natural gas-fired power generation is expected to increase to meet this demand. If unabated, this increased use of fossil-based assets will significantly increase greenhouse gas (GHG) emissions. Our analysis finds that natural gas-fired generation with carbon capture, utilization, and storage (NG+CCUS) has unrivaled potential to meet the growing demand for reliable, decarbonized power.

We conducted a comprehensive analysis, leveraging a site-specific data center demand database, detailed assessments of capture costs, and assessments of storage opportunities. We also evaluated major policy and market support for CCUS projects, to examine the full potential for CCUS on natural gas-fired generation in certain regions. Our findings indicate that NG+CCUS can satisfy all the requirements for the rapid growth of data center electricity demand and do so with reliability-adjusted emissions that are equivalent to those of renewables.

Our analysis evaluated specific opportunities to deploy CCUS at new and existing natural gas-fired generation facilities across the US and Canada. We assessed its suitability to meet escalating data center demand for clean power based on **timing**, **reliability**, **emissions**, and **cost**. Based on that analysis, we conclude the following:

1. **Timing**: Natural gas-fired generation's ability to leverage existing grid infrastructure positions it as a timely choice for supplying rapid, reliable low-emission power to data centers.
2. **Reliability**: Natural gas-fired generation is a promising option to meet the stringent reliability demands of data centers, primarily due to its inherent dispatchability and lack of intermittency issues.
3. **Emissions**: Our ELCC-adjusted[2] life cycle assessment (LCA) indicates that natural gas-fired generation with carbon capture and storage (NG+CCS)[3] could have lower effective $CO_2$ equivalent emissions than solar power backed with 4-hour battery storage.
4. **Cost**: Our market analysis identified several NG+CCUS opportunities that align with data center demand. These opportunities present a cost structure that is consistent with anticipated green premiums and demonstrate competitiveness with other low-carbon power options.

Our analysis demonstrated that by deploying CCUS at 61 existing natural-gas fired generation facilities, which are well positioned relative to carbon dioxide ($CO_2$) infrastructure and data center load growth regions, up to 126TWh of existing power generation could be decarbonized,

[1] This value represents the average of projections sourced from Lawrence Berkeley National Laboratory, Electric Power Research Institute, Goldman Sachs, the International Energy Agency.
[2] For the ELCC-adjusted LCA portion of our analysis, we looked only at NG+CCS, without utilization using ELCC from the PJM grid.
[3] In this paper, we use NG+CCUS as an umbrella term to describe all activities, carbon capture and storage (CCS) to describe storage without carbon dioxide utilization, and carbon capture (CC) to describe only the capture step. Carbon capture and utilization (CCU) refers to utilizing captured carbon dioxide as a product, as in enhanced oil recovery (EOR).

preventing the equivalent of 71 million tonnes of $CO_2$ emissions. This is equal to the annual electricity use of 14.8 million homes, or roughly all the housing units in the state of California.[4, 5]

Additionally, our analysis revealed that for existing power facilities to be suitable for retrofitting with CCUS or building new capacity with CCUS they must meet key conditions:

- **Customers:** Natural gas-fired power facilities must have customers that are willing to guarantee long-term offtake agreements and pay a green premium of up to US$30 per megawatt hour (MWh) above standard natural gas-fired generation combined cycle (NGCC) costs.
- **Transmission:** Electrical transmission capacity, from power source to data center, must be available. Often this means developing generation capacity within a region that is a net importer of electricity and that is currently transmission constrained. Not only will power generation developments within these constrained regions serve local power demand they may also ease transmission constraints by providing counterflow to proximate regions, thus increasing power load servability.
- **Infrastructure:** $CO_2$ storage options or nearby $CO_2$ transportation infrastructure must be available, either on-site or adjacent to the natural gas-fired generation facility. Self-developed infrastructure typically requires a facility to have a capacity of greater than 300 MW for project-specific development.

**For the locations where these conditions are met, NG+CCUS has a promising future as one of the few reliable, low-carbon power sources for the growing data center sector.** We share our proprietary analysis here to foster the responsible growth of clean power solutions, including NG+CCUS. With strategic planning, continuation of existing policy support, and region-specific targeted infrastructure development, Carbon Direct believes NG+CCUS will be a key factor in meeting the increasing demand for data center power while supporting decarbonization goals.

[4] US EPA O. 2015 Aug 28. Greenhouse Gas Equivalencies Calculator. [accessed 2025 Jun 25]. https://www.epa.gov/energy/greenhouse-gas-equivalencies-calculator.
[5] US Census Bureau. 2024 Jul 1. US Census Bureau QuickFacts: California. [accessed 2025 Jun 25]. https://www.census.gov/quickfacts/fact/table/CA/HSG010224.

## Introduction

By 2030, data centers are projected to grow demand for electricity by approximately 200 terrawatt hours (TWh). This represents a significant change in forecasted electrical demand in the US. While overall electricity demand in the US has remained relatively flat over the past decades, this trend is shifting to a period of high power demand growth (**figure 1**). This growth is expected to be driven by the data center boom in the near term, with demand from AI-related applications playing a substantial role. Data center demand is marked by unique characteristics such as high power density, high reliability requirements, and geographic clustering. Combined, these characteristics place strain on existing power grids. This new wave of demand presents unprecedented challenges for the energy sector but also significant opportunities to design new, low-carbon electrical production systems. The ongoing electrification of manufacturing and transportation is projected to continue to drive longer-term power demand growth. Since power generation assets have life expectancies of over 20 years, new systems put in place now will be available to meet this longer-term demand.

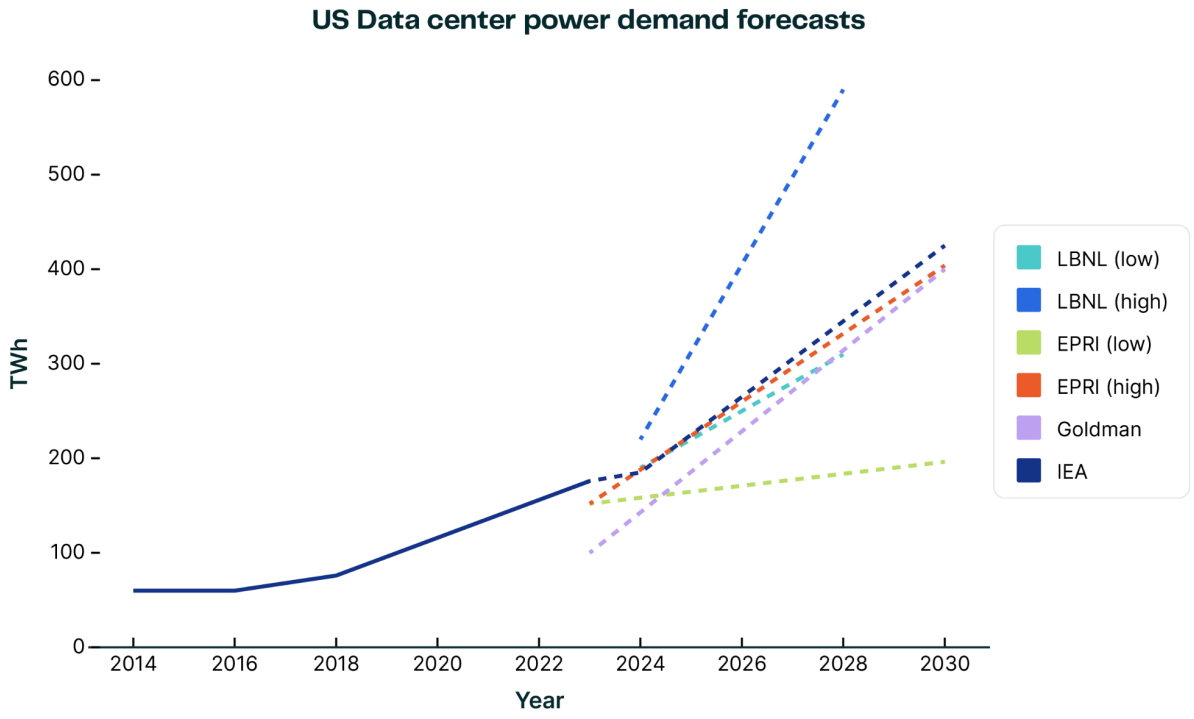



**Figure 1**: US Data center power demand forecasts. Source: Carbon Direct, based on information from Lawrence Berkeley National Laboratory (LBNL), Electric Power Research Institute (EPRI), Goldman Sachs, and the International Energy Agency (IEA).

## Meeting the power demand

Defining what type of power will be needed to address future potential demand points to a fundamental need for generating power in response to different scenarios. Natural gas-fired generation without CCUS already makes up a substantial and growing portion of electrical

generation capacity in the US, currently at about 43%.[6] However, the emissions associated with these plants remain high and hyperscalers[7] have signaled they are willing to pay a premium for decarbonized power if it meets their needs in four categories: timing, reliability,[8] emissions, and cost.

**NG+CCUS is one of the few options capable of fully servicing the requirements of new data center power demand.** These facilities meet the needs of data center hyperscalers and should be seriously considered as a viable solution:

1. **Timing:** NG+CCUS can be deployed rapidly relative to other reliable low-emission options.
2. **Reliability:** NG+CCUS offers power that is dispatchable, has a high capacity factor, and can provide continuous support without the intermittency issues faced by renewable power sources like wind and solar.
3. **Emissions:** NG+CCUS plants offer a low-carbon alternative to fossil-fueled power.
4. **Cost:** NG+CCUS can be considered cost competitive with other low-carbon power sources in a supportive policy environment and with market support in the form of green premiums.

## Timing

The interconnection queue, which comprises electricity generating projects awaiting connection to an electrical grid, is experiencing significant backlogs. Hyperscalers and data center providers have been, and continue to be, substantial purchasers of wind and solar power to meet their energy demands. However, the supply of new renewable generation in key data center development regions is constrained by interconnection queue delays. The increasing speed of data center development and deployment introduces further complexity, with the potential for significant problems by 2030 if data center deployment triples or quadruples. This scenario could further incentivize controversial strategies, such as those employed by xAI. This company allegedly exceeded its permitting requirements and potentially violated the Clean Air Act in order to keep up with electricity demands.[9] In contrast to renewable energy projects, natural gas-fired generators have been able to bypass the interconnection queue. Additionally, decarbonizing already operational natural gas plants with CCUS by retrofitting existing facilities and increasing their capacity factors is particularly appealing, as these facilities are already interconnected to the grid.

Historically, it has not been typical for natural gas-fired generators to bypass the interconnection queue. In the 1990s, a "first-in, first-out" process for new power generation was defined as part of a wholesale power deregulation movement. This process, where interconnection requests are processed in the order received, was designed to support a few energy-dense power generation projects each year. Each project requires the utility to conduct a separate, dedicated, and comprehensive study to meet federal requirements. Today, the paradigm has shifted to many simultaneous requests for interconnection from smaller-scale, intermittent, lower-capacity

[6] US Energy Information Administration. 2024 Feb 22. Use of natural gas-fired generation differs in the United States by technology and region. [accessed 2025 Jun 25]. https://www.eia.gov/todayinenergy/detail.php?id=61444.
[7] Vailshery LS. 2025 Jun 23. Topic: Hyperscaler market leaders. Statista. [accessed 2025 Jun 25]. https://www.statista.com/topics/12831/hyperscaler-market-leaders/.
[8] For the purposes of this analysis, reliability is defined by high availability and high capacity.
[9] Reuters. 2025 Apr 10. Musk's xAI increased Tennessee gas turbines without permits, community groups say. [accessed 2025 Jun 25]. https://www.reuters.com/sustainability/boards-policy-regulation/musks-xai-increased-tennessee-gas-turbines-without-permits-community-groups-say-2025-04-09/.

renewable energy projects, a pattern that does not fit within the established process. This has created a years-long interconnection queue[10] and a backlog of 2,600,000 MW waiting to be connected.[11] This is double the current installed capacity of grids across the US, which totals 1,300,000 MW.[12]

In July 2023, a new federal order defined the current generation process, which allows grid operators to shift from the "first-in, first out" process to a **"first ready, first served"** model. We are now seeing the effects of the order take shape for grid operators throughout the US, with decreased connection times for high-reliability generators. The exception is the Electric Reliability Council of Texas (ERCOT) grid in Texas, which is not regulated by the Federal Energy Regulatory Commission (FERC). However, ERCOT has been independently making interconnection reforms to address backlogged generation that are akin to the new federal generation process.

In response to the new federal order, PJM (one of the largest regional transmission organizations in the US) recently created the Reliability Resource Initiative (RRI).[13] This initiative ushered through 9,300 MW of new capacity, 86% of which is from natural gas-fired facilities, to bypass the interconnection queue and meet grid reliability requirements in the near term. This rapid movement of natural gas-fired generation capacity to the front of the queue reflects its unique reliability—a key measurement of its fitness for meeting demand. Grids are increasingly turning to natural gas-fired power facilities to provide reliable electricity in a timely manner.

## Reliability

Reliability is paramount for most data centers, whose operators typically require uninterrupted, on-demand power across all hours of the year. Since no single generation source is capable of meeting this demand, it is imperative to compare different power sources. Historically, there has not been a clear way to compare each source's relative contribution to a grid. However, for this paper, we have leveraged a well-established methodology, used by grid-operators to allocate system benefits to individual generators, to address a key challenge for emission comparisons: **effective load carrying capacity (ELCC)**. This methodology allows us to develop highly accurate emissions comparisons between different options, such as comparing NG+CCS to wind turbines, to validate the true cost of carbon abatement.

In many regions, meeting a grid's energy and reliability requirements through expanded natural gas-fired generation increases emissions. Against this backdrop, NG+CCS emerges as a compelling solution. Unlike renewable power with variable reliability, NG+CCS plants can offer dispatchable, reliable power that aligns with the operational needs of data centers. When equipped

[10] Lawrence Berkeley National Laboratory. 2024. Queued Up: 2024 Edition. [accessed 2025 Jun 25]. https://emp.lbl.gov/sites/default/files/2024-04/Queued%20Up%202024%20Edition_R2.pdf
[11] Lawrence Berkeley National Laboratory. 2024. Grid connection backlog grows by 30% in 2023, dominated by requests for solar, wind, and energy storage | Energy Markets & Policy. [accessed 2025 Jun 25]. https://emp.lbl.gov/news/grid-connection-backlog-grows-30-2023-dominated-requests-solar-wind-and-energy-storage.
[12] American Public Power Association. 2025. America's Electricity Generating Capacity. [accessed 2025 Jun 25]. https://www.publicpower.org/resource/americas-electricity-generating-capacity.
[13] PJM 2025 May 2. PJM Chooses 51 Generation Resource Projects To Address Near-Term Electricity Demand Growth | PJM Inside Lines. [accessed 2025 Jun 25]. https://insidelines.pjm.com/pjm-chooses-51-generation-resource-projects-to-address-near-term-electricity-demand-growth/.

with CCS systems that have a high capture rate, these facilities can deliver electricity with a significantly reduced carbon footprint, bridging the gap between reliability and decarbonization.

**What is effective load carrying capacity?**
Effective load carrying capacity (ELCC) is a metric that is used to estimate the system impact of an individual generator. While ELCC has been around for decades, it is gaining popularity due to increased intermittent power generation on grids. Our analysis uses ELCC to illustrate that NG+CCS is a highly competitive option for power supply, with carbon emissions comparable to other low-carbon alternatives. In order to compare different power generators with vastly different characteristics, we used combinations of assets that provide comparable amounts of energy and reliability to a grid such as: renewables plus storage versus a consistent generator such as combined cycle gas turbine.

We then compare these systems by estimating the ELCC of each one. ELCCs account for the reliability of the power system, and grid operators use them to assign the probability of a generator's capacity to generate electricity for certain high-load periods on that grid throughout the year. There is established and growing work to optimize power systems to better meet reliability, generation, and decarbonization goals. However, to our knowledge, no published life cycle assessment (LCA) studies consider ELCCs.[14] In general, academic LCAs and databases with emission factors for electricity generation technologies do not consider reliability or availability at all. Some new research is attempting to correct for this issue by adding battery energy storage systems (BESS) to renewables such that they are as dispatchable as baseload, natural gas-fired assets.[15] However, enforcing such stringent constraints may not be required in practice. A more general approach is needed.

To address this need, we suggest a novel approach to comparing individual generators' emission impacts on a power system, the ELCC-adjusted MWh. We based our analysis on ELCC-adjusted MWhs to capture the difference between MWh of electricity and MWh of electricity when and where it is needed. Essentially, we levelized the carbon intensity of each power-generating technology by its ELCC. ELCC ranges were adapted from PJM's estimates through 2035.[16] The use of grid-specific ELCCs is an area for future study, as ELCCs will differ for each electricity-generating technology based on geography, the local grid mix, and weather-based variations.

## Emissions

Comparing the emissions profiles of different power sources has been difficult because methods to compare reliability have been lacking. Fundamental differences exist between emissions from manufacturing a solar panel array versus the lifetime emissions of a natural gas-fired generator. This means that a direct comparison is not viable. Attempts have been made to show the potential

[14] MEGS: Modelling energy and grid services to explore decarbonisation of power systems at lowest total system cost. 2021. Energy Strategy Reviews. 38:100709. doi:10.1016/j.esr.2021.100709.
[15] Das J, Ur Rehman A, Verma R, Gulen G, Young MH. 2024. Comparative Life-Cycle Assessment of Electricity-Generation Technologies: West Texas Case Study. Energies. 17(5):992. doi:10.3390/en17050992.
[16] PJM. 2024. Preliminary ELCC Class Ratings for period Delivery Year 2026/27 – Delivery Year 2034/35. [accessed 2025 Jun 25]. https://www.pjm.com/-/media/DotCom/planning/res-adeq/elcc/preliminary-elcc-class-ratings-for-period-2026-2027-through-2034-2035.pdf.

impact of the carbon emissions per MWh for various power sources, but rely on many assumptions for each site that are greatly impacted by regional weather variations and the current supply of electricity to a grid. These methods have high retrospective accuracy but poor predictive performance. By using the ELCC approach to comparing emissions profiles of different power sources, we significantly improved predictive performance and showed that NG+CCS emissions are on par with other low-carbon sources of power.

In order to compare power systems, we took the ELCC approach outlined above and used it to conduct LCAs of different power systems. All supporting information for the LCAs may be found in *Appendix A*. In this analysis, we consider natural gas-fired generation systems, a nuclear power generator, and utility-scale wind or solar generating facilities with BESS. We used the ELCC approach to calculate ELCC-adjusted carbon intensities (EACIs) for each option, offering an efficient means of comparison.[17]

The results of one such analysis are shown in **figure 2**, but only apply to generators under PJM's service area and do not include grid impacts. More details may be found in *Appendix A*. In this example, nuclear-derived electricity has the lowest EACI. This is a reflection of its already low operational carbon intensity (CI)—it emits no greenhouse gases during electricity generation—and its high ELCC. Natural gas-fired generators have an average EACI in the high 500s. Wind + 4-hour BESS has an EACI that is just above 100 kg $CO_2e$/MWh. Solar photovoltaic (PV) + 4-hour BESS has an EACI that is about 20% higher than NGCC+CCS, which has an average EACI of 130 kg $CO_2e$/MWh (as modeled using this study's data). This is because solar cannot produce electricity at all hours of the day and produces significantly less under cloudy conditions. Meanwhile, NGCC+CCS can theoretically produce electricity at all hours of the day. This phenomenon is captured in an EACI-based comparison, which clearly demonstrates the effectiveness of leveraging ELCC to normalize emissions of electricity-generating systems by availability.

[17] For example, if a facility with an ELCC of 90% generates 1 MWh in its life and emits 100 kg $CO^2e$ throughout its life cycle, it generates (1 x 0.9) = 0.9 ELCC-adjusted MWh and its EACI is (100/0.9) = 111.1 kg $CO_2e$/MWh.

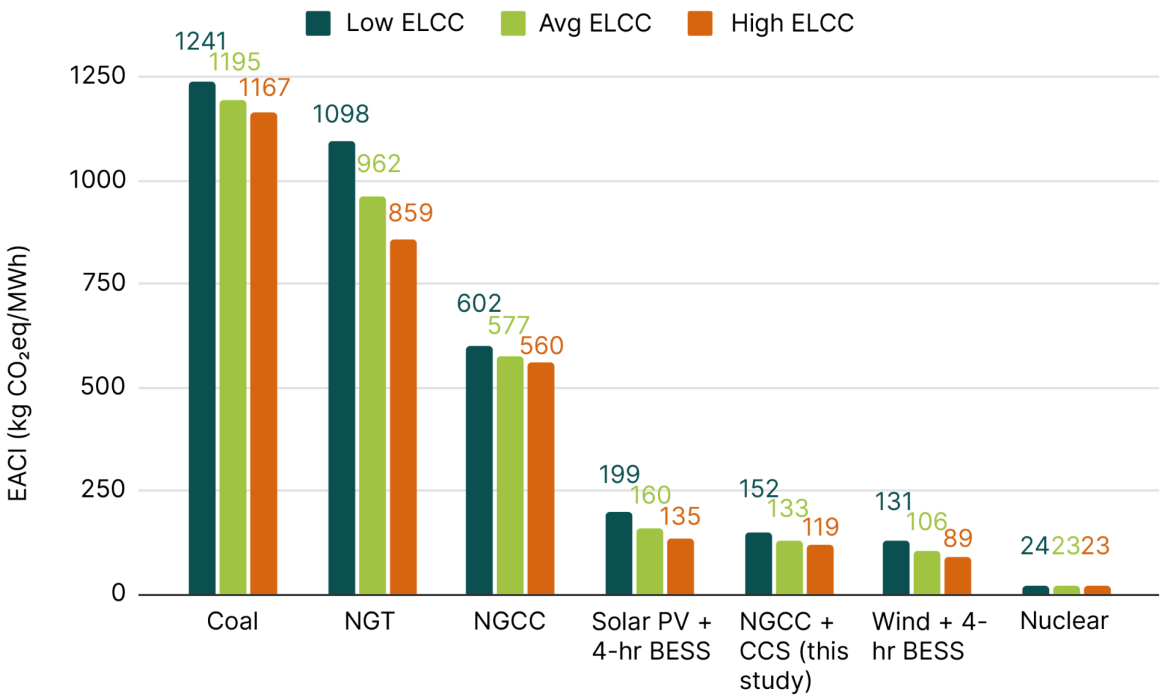



**Figure 2.** EACIs for different generators. NGCC+CCS assumes 97.5% capture, an upstream methane leakage rate of 0.75% (mass basis), and an overall upstream natural gas carbon intensity of 10.3 kg $CO_2$e per million British thermal units at the lower heating value. Note: BESS = battery energy storage systems, EACI = ELCC-adjusted carbon intensity, ELCC = effective load carrying capacity, NGCC + CCS = natural gas combined cycle with carbon capture and storage, NGT = natural gas turbine, PV = photovoltaic. Source: Carbon Direct.

**Applicability to different natural gas-fired facilities: comparing utilization to storage**

In addition to the ELCC-adjusted LCA for NGCC+CCS, we examine NGCC facilities where multiple products are generated. We used a rigorous LCA methodology to estimate the CI of electricity produced from NG+CCUS, on its own and relative to other options for electricity generation (see discussion on ELCC above). Our LCA accounts for scenarios where an NGCC+CCUS facility might produce up to three products: **electricity**, **steam**, and an **intermediate $CO_2$** product that can be utilized downstream in synthesis of chemicals, fuels, or enhanced oil recovery (EOR). Customers or users of all three products may wish to know each product's CI. If the $CO_2$ is stored and not used, emissions are only allocated to steam and electricity products.[18] All data inputs, assumptions, methodological choices, goal and scope definitions, allocation methods, system boundaries, and baseline NGCC emissions without carbon capture (CC) may be found in *Appendix A*.

**Electricity CI depends on products produced at the facility:** The electricity CI was calculated on three NG+CCS systems with no steam export (a baseline system, a new-build system, and a CCS retrofit on an existing facility), as shown in **figure 3**. Depending on the heat rate of the facility, cradle-to-grave CIs range from 79–109 kg $CO_2$e/MWh. Emissions from the natural gas supply

[18] This is true even if 45Q revenue is realized for the stored $CO_2$. "Fossil $CO_2$ sequestered underground" is not a functionally useful product. So according to ISO LCA standards, environmental burdens must not be allocated to it.

chain, including methane leaks, dominate life cycle GHGs, accounting for about 87% of emissions in all cases.

**Figure 4** shows CIs for electricity and steam for an NGCC+CCUS facility with increasing levels of steam export. In our analysis, we allocated emissions on the basis of exergy.[19] Since roughly 50% of the exergy in steam is lost across the steam turbine, siphoning the steam before this point increases exergy exports. Therefore, CIs of each product decreases since there is more exergy for the same amount of emissions. Depending on the amount of steam exported, the CI of electricity varies from 62–93 kg $CO_2$e/MWh, and the CI of steam varies from 18–27 kg $CO_2$eq/MMBTU.

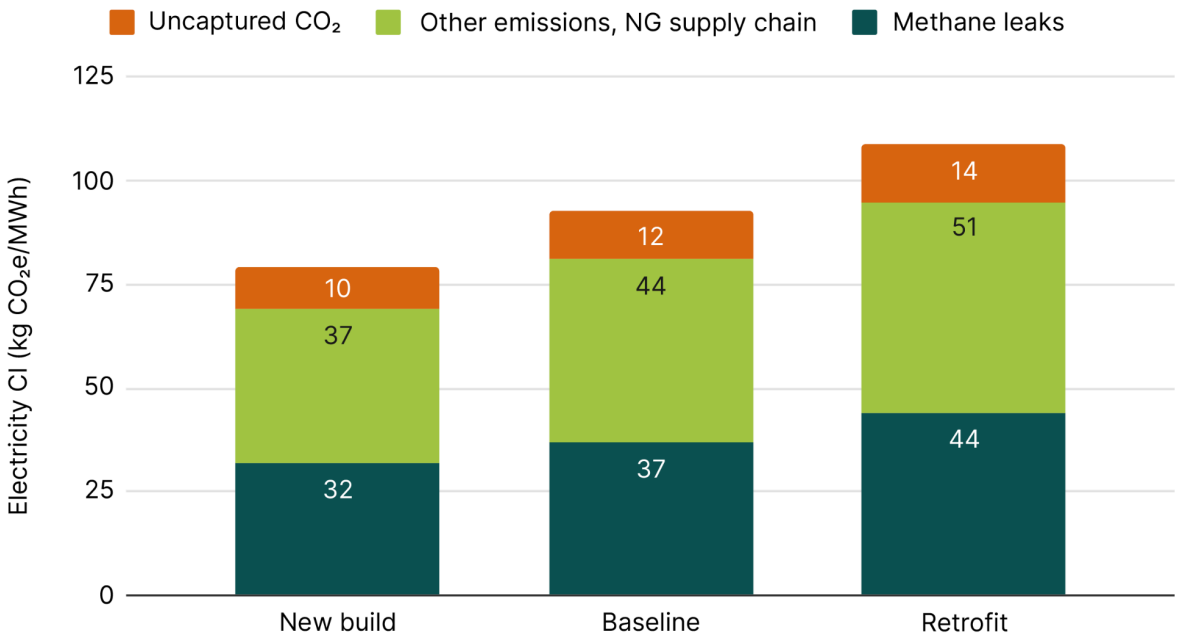



**Figure 3.** Electricity carbon intensity without steam export to downstream customers, where compressed $CO_2$ is stored and not utilized (NG+CCS). Source: Carbon Direct.

[19] Exergy is the maximum useful work that can be extracted from a system as it comes into equilibrium with its surrounding environment. While energy is a conserved quantity (the first law of thermodynamics), exergy is not. Exergy can be destroyed during processes, due to increases in entropy.

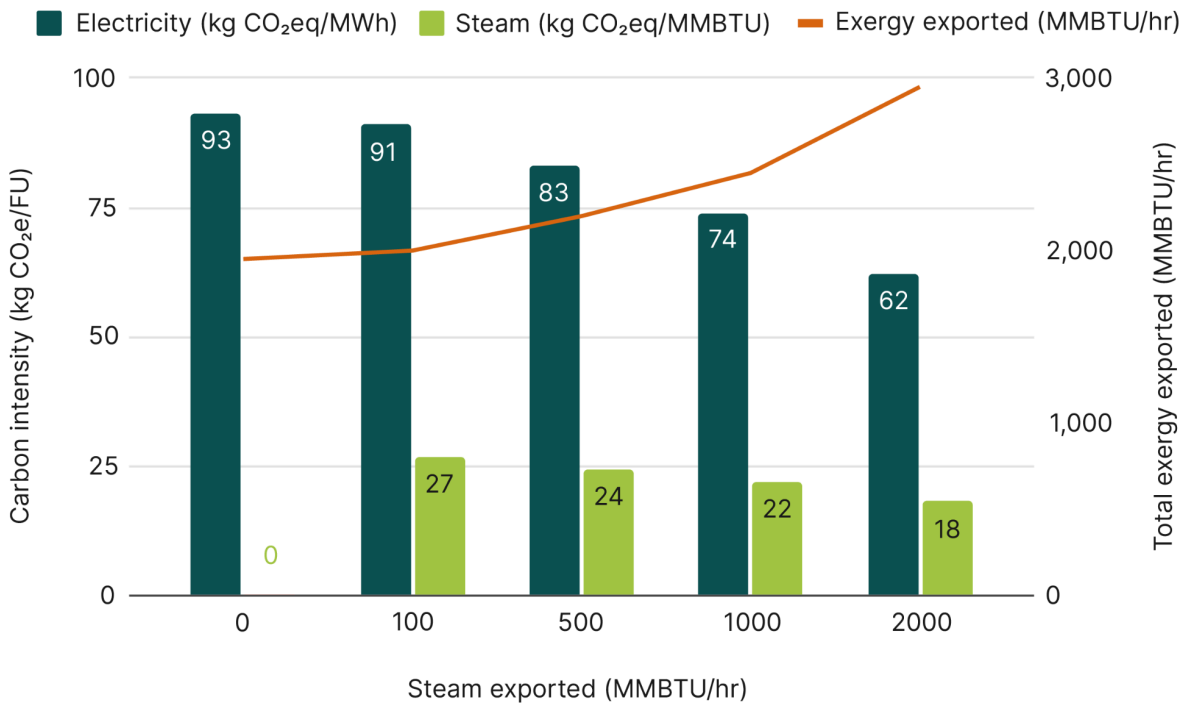



**Figure 4.** Carbon intensities of electricity and steam as a function of steam exported to downstream customers. Total exergy is tracked on the right vertical axis. Source: Carbon Direct.

Finally, we consider the case where $CO_2$ is utilized as an intermediate product. In this case, all emissions associated with operation of the carbon capture train and $CO_2$ compression must be allocated only to the $CO_2$ product (since these processes do not produce any electricity or steam products). Therefore, the CI of electricity will decrease relative to the case where $CO_2$ is stored. The electricity CIs for varying facility heat rates for this case are shown in **figure 5**. The CI for electricity varies from 47–57 kg $CO_2$e/MWh. The natural gas supply chain, including methane leaks, now accounts for 100% of these emissions.

As above, CIs for electricity, steam, and $CO_2$ products all decrease with increasing export rates of the steam product. This phenomenon is shown in **figure 6**.

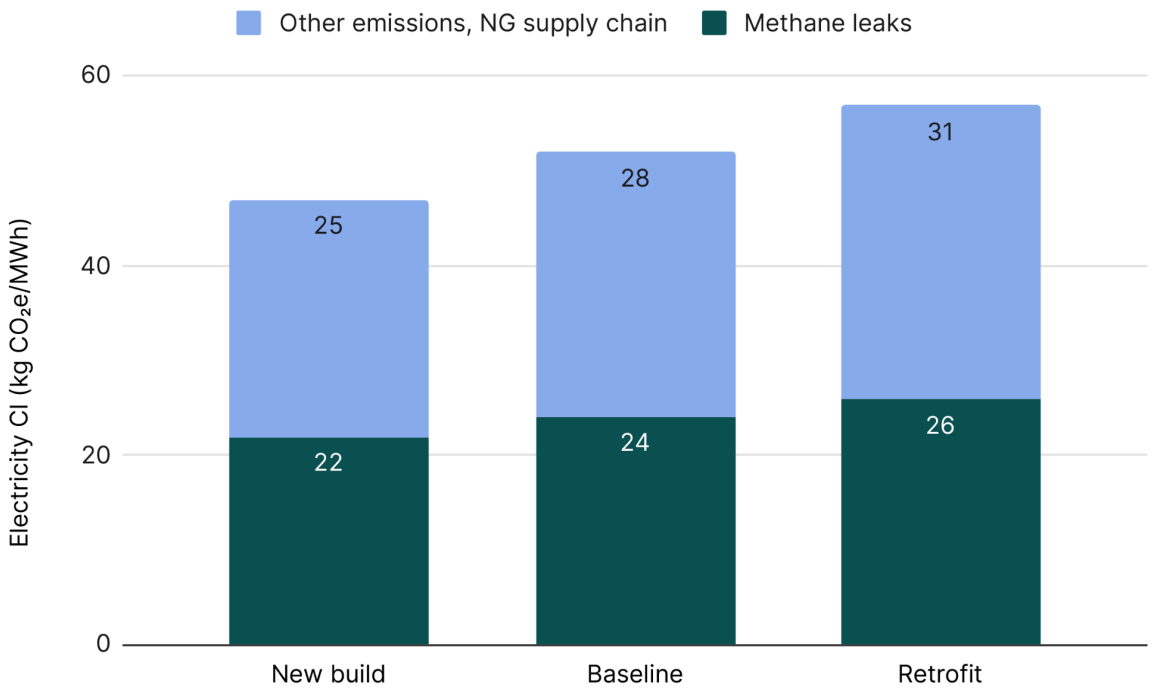



**Figure 5.** Carbon intensity of electricity for an NGCC+CCU system when compressed $CO_2$ is considered a product, and without steam export to downstream customers. Methane leakage rate is 0.75% (energy basis). Source: Carbon Direct.

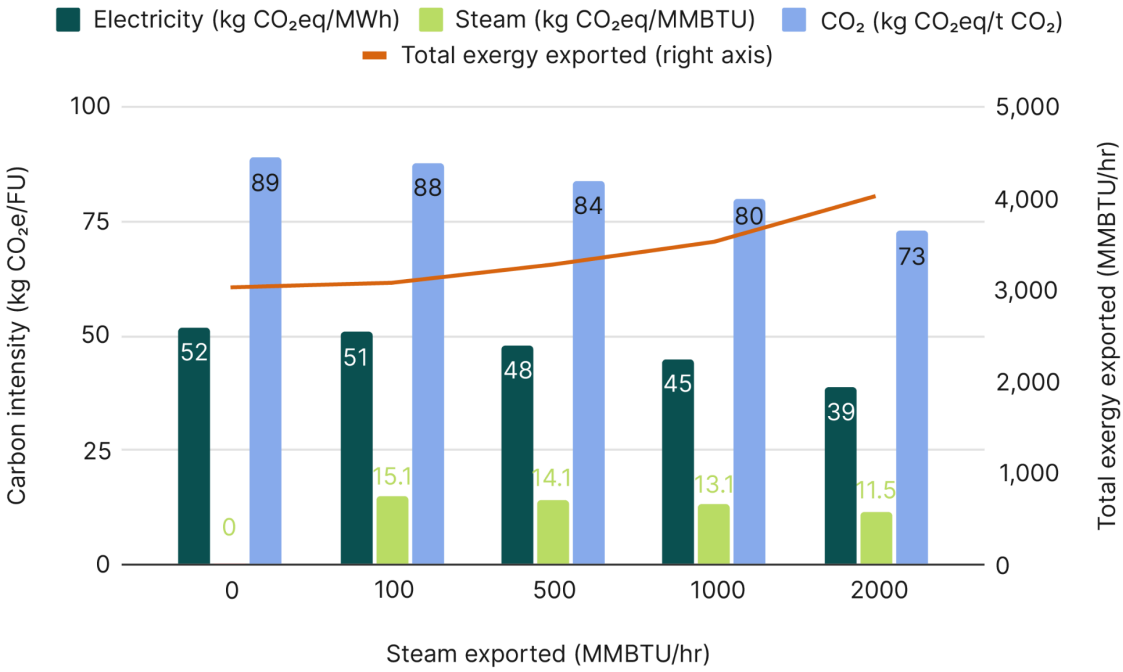



**Figure 6.** Carbon intensities of each product for an NGCC+CCUS system, where compressed $CO_2$ is considered a product and as a function of steam export to downstream customers. Total exergy exported in all products is tracked on the right vertical axis. Source: Carbon Direct.

## Cost

The same issues prevalent in comparing reliability and emissions across technologies can also make cost comparisons extremely challenging. The ELCC, as defined above, allows us to simplify this comparison and dive into the details of site-specific constraints on a site-by-site basis.

The electricity supply market is very competitive. Due to individual generator impacts on local grids, not all MW's are created equal. In spite of this, the levelized cost of electricity (LCOE) is the predominant metric used to compare the cost of different power generating technologies.[20, 21] Without including adjustments for reliability, and more nuanced adjustments for the cost of carbon storage, a simple cost comparison of different technologies shows that NGCC, while competitive, requires existing policy incentives **and** a green premium when adding CCS (**table 1**).

Recent deal announcements between hyperscalers and power generators have clearly demonstrated a willingness to pay a premium for low carbon baseload or dispatchable power.[22]

**Table 1.** Levelized cost of electricity

| | NETL[23] | EIA LCOE[24] | Lazard LCOE[25] |
|---|---|---|---|
| **Nuclear** | n/a | US$71/MWh | US$141–228/MWh |
| **NGT** | n/a | US$129/MWh | US$149–228/MWh |
| **Wind + 4-hr BESS** | n/a | n/a | US$44–123/MWh |
| **Solar PV + 4-hr BESS** | n/a | US$37/MWh | US$50–131/MWh |
| **NGCC** | n/a | US$43/MWh | US$48–109/MWh |
| **NGCC + CCS** | US$69/MWh (2020) | n/a | n/a |

Note: BESS = battery energy storage systems, EIA = Energy Information Administration (United States), IEA = International Energy Agency, LCOE = levelized cost of electricity, NGCC + CCS = natural gas combined cycle with carbon capture and storage, NGT = natural gas turbine, PV = photovoltaic.

To analyze the feasibility of carbon capture on natural gas-fired generators, we calculated the actual cost for every individual natural gas-fired generator using multiple factors (as detailed in the

[20] Clean Air Task Force. 2025. Beyond LCOE: A Systems-Oriented Perspective for Evaluating Electricity Decarbonization Pathways. [accessed 2025 Jun 25]. https://www.catf.us/resource/beyond-lcoe/.
[21] Lazard. 2025. Levelized Cost of Energy+ (LCOE+). https://www.lazard.com. [accessed 2025 Jun 25]. https://www.lazard.com/research-insights/levelized-cost-of-energyplus-lcoeplus/.
[22] Reuters. 2024 Sep 24. Microsoft may pay Constellation premium in Three Mile Island power agreement, Jefferies says (Sept 23). [accessed 2025 Jun 25]. https://www.reuters.com/markets/deals/microsoft-may-pay-constellation-premium-three-mile-island-power-agreement-2024-09-23/.
[23] Schmitt T, Leptinsky S, Turner M, Zoelle A, White CW, Hughes S, Homsy S, Woods M, Hoffman H, Shultz T, et al. 2022. Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity. National Energy Technology Laboratory (NETL), Pittsburgh, PA, Morgantown, WV, and Albany, OR (United States) Report No.: DOE/NETL-2023/4320. [accessed 2025 Jun 25]. https://www.osti.gov/biblio/1893822.
[24] US Energy Information Administration (EIA). 2025. Levelized Costs of New Generation Resources in the Annual Energy Outlook 2025. EIA Annual Energy Outlook. [accessed 2025 Jun 25]. https://www.eia.gov/outlooks/aeo/electricity_generation/.
[25] Lazar, Levelized Cost of Energy+.

*Market analysis methodology* section). Using the low-emission premium market indicators, we set a maximum cost target to align with the premiums. For our analysis, we chose US$30/MWh as a target commercial green premium, which is in addition to the typical NGCC supply price and is normalized for NGCC plants. This means higher reliability plants (like nuclear if it could meet the timing constraints), would have a higher green premium maximum. This value represents the combined average of the estimated minimum additional premiums that data center developers and operators have paid for restarted nuclear, geothermal, solar + BESS and other low-carbon generation options, compared to typical NGCC dispatch pricing. In order to meet these cost targets, policy support is required and is already in place at significant levels for both the US and Canada.

## Policy support and incentives

To fully cover the cost of CCUS, policy incentives, such as the current 45Q carbon oxide sequestration tax credit in the US and the Output-Based Pricing System (OBPS) in Canada, can be combined with a higher willingness to pay for decarbonized power.

### Policy support in the US

In the US, a suite of federal incentives—most notably the 45Q tax credit along with grants and loans—have underpinned the business case for CCUS deployment. In 2022, Congress passed the Inflation Reduction Act (IRA), which made several reforms, enhancements, and expansions to these programs (**table 2**). Beginning in early 2025, however, Congress has proposed a number of changes that may reduce the effectiveness of the 45Q credit. Since 2008, 45Q has benefited from strong bipartisan support and been amended multiple times to enhance credit values and to generally make the incentive more accessible and creditworthy. During the 119th Congress, the House and the Senate provided markups for reconciliation legislation that could have comparatively modest impacts on the eligibility and transferability provisions of the credit. Relative to other clean energy incentives established or enhanced through the IRA, under both chambers' proposed markups, 45Q maintains its credit values and phaseout schedule. Our analysis utilizes what we view as the most likely scenario, based on publicly indicated preferences from congressional leadership, although significant legislative action on the reconciliation package remains to be done at the time of the writing.

**Table 2.** Inflation Reduction Act changes to 45Q tax credit values

| | **Pre-IRA credit value*** | **Post-IRA credit value**** |
|---|---|---|
| **Credit for secure geological storage, excluding enhanced oil recovery (EOR) and enhanced gas recovery (EGR)** | US$50/tonne | US$85/tonne |
| **Credit for utilization, including EOR and EGR** | US$35/tonne | US$60/tonne |
| **Credit for sequestration from direct air capture (DAC)** | US$50/tonne | US$180/tonne |
| **Credit for utilization from DAC** | US$35/tonne | US$130/tonne |

* This value assumes prevailing wage and registered apprenticeship requirements are met.
**These tax credits values are indexed for inflation beginning in 2026.

**The 45Q tax credit: The backbone of federal CCUS incentives**

The 45Q Carbon Oxide Sequestration Credit provides a tax credit for each tonne of carbon that is captured and sequestered or utilized, either through tertiary recovery of hydrocarbons or conversion of carbon oxides to other products. The IRA made several reforms and enhancements to the credit, including extending the deadline to begin construction of qualified facilities from 2026 to 2032, lowering the minimum capture amounts for all qualified facilities, and allowing for credit transferability and direct (or elective) pay. The IRA also raised the credit values to US$85/tonne for permanent sequestration from point-source capture, US$60/tonne for utilization from point-source capture, US$180/tonne for sequestration from direct air capture (DAC) systems, and US$130/tonne for utilization from DAC systems, provided recipients satisfy the prevailing wage and apprenticeship requirements. Qualified projects must commence construction before the end of 2032, and the credit expires 12 years from when a facility is placed in service. This means that a facility placed in service before the end of 2032 could generate credits though 2044. Proposed changes to 45Q to give the full credit for 45Q to EOR. Other utilization applications were considered in our market analysis.

**Grants and loans: derisking commercialization**

Beyond tax credits, under President Biden, the Department of Energy (DOE) dramatically expanded its direct support for CCUS through grants and loans. Under the programs created or expanded by the IRA and the Infrastructure Investment and Jobs Act (IIJA), the DOE announced over US$3.5 billion in funding opportunities for carbon capture and transport technologies, including US$1.3 billion in funding for point source CCS demonstration projects and regional carbon management networks.[26] As of June 2025, IIJA and other funding opportunities, negotiations, and awards (in some instances) are paused and pending review by the Trump Administration. However, recent court orders have restrained the ability of the Administration to outright halt the issuance of Congressionally authorized and appropriated funds, opening the door to their restoration.[27]

**Sequestration wells**

The US Environmental Protection Agency (EPA) is tasked with reviewing Underground Injection Control (UIC) permit applications under the Safe Drinking Water Act. The process for attaining the required EPA Class VI permit has been very time intensive. This is to account for first-of-a-kind and rigorous evaluation of the well design, reservoir, and seismicity concerns, though EPA has enhanced transparency regarding review timelines.[28] The EPA has delegated primary enforcement and permit approval authority for Class VI wells, known as primacy, to Louisiana, North Dakota, West Virginia, and Wyoming, which has the potential to reduce these delays. Other states, including Arizona and Texas, are in the process of obtaining primacy as well. The lengthy timeline for obtaining a Class VI well permit has previously posed a barrier for companies that were aiming to meet the additional 45Q tax credit requirements for permanent $CO_2$ storage. However, these

[26] Grants.gov. 2024. Search Results Detail | Grants.gov. [accessed 2025 Jun 25]. https://www.grants.gov/search-results-detail/357824.
[27] US Department of Energy. 2025. Notice of Court Orders. Energy.gov. [accessed 2025 Jun 25]. https://www.energy.gov/notice-court-orders.
[28] US Environmental Protection Agency. 2025 Jun 20. UIC Class VI Wells Permit Tracker Dashboard. [accessed 2025 Jun 25]. https://awsedap.epa.gov/public/single/?appid=8c074297-7f9e-4217-82f0-fb05f54f28e7&sheet=51312158-636f-48d5-8fe6-a21703ca33a9&theme=horizon&bookmark=6218ffed-bb6e-42e4-a4f1-52d87e036a1b&opt=ctxmenu.

delays have already shortened and are expected to align with typical engineering and design timelines.

## Policy support in Canada

Canada has a long history of strong federal, provincial, and territorial policy support for decarbonization, primarily through the utilization of carbon pricing schemes and investment tax credits. Canada's carbon pricing schemes have been enforced at the provincial level since 2008. In 2019, the Greenhouse Gas Pollution Pricing Act established a national benchmark for carbon pricing to ensure a similar level of stringency nationwide. The national pricing scheme has two parts: a consumer-pay fuel charge and the OBPS, a performance-based system for industries. The revenue from the industrial carbon price is reinvested into the jurisdictions where the federal OBPS applies through two programs: the Decarbonization Incentive Program and the Clean Electricity Fund.

In April 2025, the Canadian federal government removed the consumer-pay fuel charge, but the national industrial carbon tax (a key component of the OBPS) remains a critical tool for driving decarbonization. The national industrial carbon tax applies to industrial facilities located in the provinces and territories[29] of Manitoba, Nunavut, Prince Edward Island, and Yukon. Other territories and provinces have their own carbon pricing scheme for industrial emissions. Currently, the national backstop compliance cost for emissions exceeding the allowance is CAD$95/tonne, and increases by CAD$15/tonne each year until 2030.[30]

In addition to carbon pricing schemes, Canada also provides support for decarbonization with an investment tax credit (ITC) for CCUS, which was established through the enactment of Bill C-59, the Fall Economic Statement Implementation Act, 2023 along with three other Clean Economy Investment Tax Credits.[31] The CCUS ITC is valued at CAD$3.1 billion in the first five years and around CAD$7.6 billion by 2030. Eligible projects,[32] commissioned after April 7, 2022 until December 2040, can receive this refundable ITC to cover the costs of DAC, point-source carbon capture, transport, storage, and usage equipment. The value of the CCUS ITC differs based on application.[33] For capture equipment used in DAC projects, the value is 60%, compared to 50% on

[29] Government of Canada. 2025 Jan 13. Carbon pollution pricing for industry. [accessed 2025 Jun 25]. https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/putting-price-on-carbon-pollution/industry.html.
[30] Government of Canada. 2025 Mar 14. Output-Based Pricing System. [accessed 2025 Jun 25]. https://www.canada.ca/en/environment-climate-change/services/climate-change/pricing-pollution-how-it-will-work/output-based-pricing-system.html.
[31] Government of Canada. 2024 Jun 21. Government of Canada Launches the First Clean Economy Investment Tax Credits. [accessed 2025 Jun 25]. https://www.canada.ca/en/natural-resources-canada/news/2024/06/government-of-canada-launches-the-first-clean-economy-investment-tax-credits.html.
[32] Government of Canada. 2022 Aug 9. Additional Design Features of the Investment Tax Credit for Carbon Capture, Utilization and Storage: Recovery Mechanism, Climate Risk Disclosure, and Knowledge Sharing. [accessed 2025 Jun 25]. https://www.canada.ca/en/department-finance/news/2022/08/additional-design-features-of-the-investment-tax-credit-for-carbon-capture-utilization-and-storage-recovery-mechanism-climate-risk-disclosure-and-k.html.
[33] Government of Canada. 2024 Jun 21. Calculating the credit - Carbon Capture, Utilization, and Storage (CCUS) Investment Tax Credit (ITC). [accessed 2025 Jun 25]. https://www.canada.ca/en/revenue-agency/services/tax/businesses/topics/corporations/business-tax-credits/clean-economy-itc/carbon-capture-itc/claiming-credit-ccus-itc/calculate.html.

expenditures for point-source carbon capture. For qualified carbon transportation, storage, or usage equipment, the value of this ITC is 37.5%. The CCUS ITC is likely to remain intact post-election due to its direct investment into Canadian businesses—a favorable strategy for Canada's leading parties.

### Policy support in the European Union and the United Kingdom

There is substantial and growing support for CCUS in the European Union (EU), driven by the bloc's ambitious climate targets and the need to decarbonize heavy industry. The EU Clean Industrial Deal will mobilize over €100 billion toward clean manufacturing within the bloc, and CCUS is an eligible technology. The European Commission is expected to introduce new funding mechanisms to scale carbon management technologies to 50 $MtCO_2$/year by 2030 (representing six- to ten-fold growth) and to 280 $MtCO_2$/year by 2040 (representing 100-fold growth) in support of the Industrial Carbon Management Strategy. Carbon Direct has published a thorough analysis on the EU's Industrial Carbon Management Strategy.[34]

The United Kingdom (UK) government has made CCUS a central pillar of its strategy to achieve net zero emissions by 2050. Support to scale CCUS is made available through financial, regulatory, and strategic resources. This includes allocation of £21.7 billion over 25 years[35] to two point-source capture projects located at industrial sites, one of which is a CCUS enabled hydrogen plant. The UK follows a similar approach as the EU when scaling CCUS projects. Funding is not provided in the form of tax credits, like in the US and Canada. Instead, the UK and EU established funding programs with limited capital, and the governments select projects to receive funds in an effort to scale CCUS projects.

## Market analysis

Substantial opportunities exist today to address a large portion of the growing demand for electricity with NG+CCUS, and further opportunities are possible with the right policy incentives. Currently, our models indicate that no power generation facilities balance CCS capital and operating costs through 45Q tax credits alone. This is unsurprising as the 45Q credit was considered before inflation (2022 through Jan 2025) and tariff uncertainties. In addition, the few exceptional cases that might be economically feasible (due to their locations in regions with high data center demand) are not typically co-located with readily available Class VI well permits for $CO_2$ storage (**figure 7**). Most importantly, this also does not account for first-of-a-kind contingencies. These findings align with other recent studies, including those conducted by the National Energy Technology Laboratory (NETL).[36]

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[34] Carbon Direct. 2024. Driving deeper decarbonization: Implications of the EU's ambitious new goals and targets. [accessed 2025 Jun 25]. https://www.carbon-direct.com/research-and-reports/driving-deeper-decarbonization-implications-of-the-eu-s-abitious-new-goals-and-targets.

[35] GOVUK. 2024 Oct 4. Government reignites industrial heartlands 10 days out from the International Investment Summit. [accessed 2025 Jun 25]. https://www.gov.uk/government/news/government-reignites-industrial-heartlands-10-days-out-from-the-international-investment-summit.

[36] LaBarbara K. 2023. Economics of Competing CCS Plants. National Energy Technology Laboratory. [accessed 2025 Jun 25]. https://netl.doe.gov/sites/default/files/netl-file/23CM_PSCC28_Labarbara.pdf#:~:text=Fuel%20cost%20from%20an%20average,CF%20running%20the%20whole%20year.

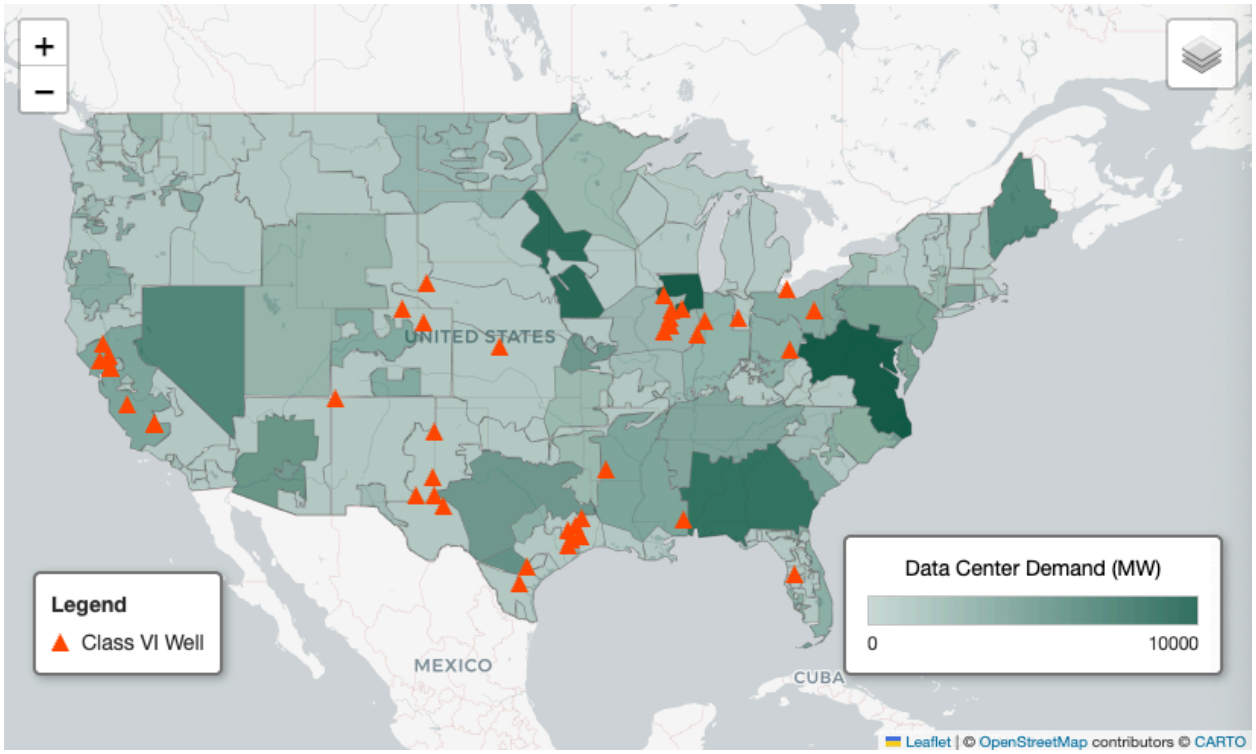



**Figure 7**: Power-constrained regions experiencing high data center demand for power (including data centers under construction and projected builds and locations of Class IV wells). In this analysis, WattTime regions are utilized as a proxy to delineate distinct electricity grids and infer associated transmission constraints. Note: Higher demand is indicated by darker shades of green, and lower demand is indicated by lighter shades. The locations of Class VI wells are indicated by orange triangles. Source: Carbon Direct.

Given these economic realities, successfully deploying CC technologies in power generation facilities requires end-users that are willing to bear a green premium for electricity with a lower CI. Additionally, CCUS requires new contracts, which are usually best paired with new demand. This makes the data center industry a primary target for such initiatives. Our analysis aimed to find alignment between data center demand locations and access to viable NG+CCUS opportunities.

## Market analysis methodology

Our analysis employed a two-pronged approach: a bottom-up market assessment followed by a top-down opportunity filtering process. CCUS retrofit costs were calculated for each emission source, based on our comprehensive infrastructure database. We summarize and present our analysis below, focusing on locations where policy or market interventions are crucial for viability. Specific cost figures remain confidential. Our methodology is summarized in **table 3** and further explained in *Appendix B*.

**Table 3.** Market analysis methodology

| Item addressed by Pre-FEED, FEED, or LCCA | Failure risk uncertainty after Pre-FEED | Cost uncertainty after Pre-FEED | Timing uncertainty after Pre-FEED | Pre-FEED | FEED | LCCA |
|---|---|---|---|---|---|---|
| Demand location | | | | Single site | Single site | Entire country |
| Water availability | 15% | | | 🚫 | ✅ | ✅ |
| Disposal cost | | US$10–30 | 2–4 years | 🚫 | ✅ | ✅ |
| Transportation cost | | US$10–30 | | 🚫 | ✅ | ✅ |
| Political support/resistance | 30% | | | 🚫 | 🚫 | ✅ |
| Natural gas capacity | 20% | | | 🚫 | ✅ | ✅ |
| Grid operator support | 20% | | | 🚫 | ✅ | ✅ |
| Transmission capacity | | US$10–30 | | 🚫 | ✅ | ✅ |
| Grid voltage + frequency | | US$5–7 | | 🚫 | 🚫 | ✅ |
| Site infrastructure | 20% | | 1–2 years | 🚫 | ✅ | ✅ |
| Operating costs | | US$5-10 | | 🚫 | ✅ | ✅ |
| Capital costs | | US$5–10 | | 🚫 | ✅ | 🚫 |
| Engineering costs | | US$3–5 | | ✅ | ✅ | 🚫 |

Note: FEED = front-end engineering design, LCCA = levelized cost of carbon abatement.

## Data center load growth analysis

Data center developers are rapidly constructing and announcing new projects in order to serve growing demand, driven in part by the growth in AI. Many of these same developers have also signaled their intent to service this growth with low-carbon electricity, with some announcing power purchase agreements (PPAs) to this effect.[37, 38]

[37] Hollis B. 2024. Accelerating the addition of carbon-free energy: An update on progress. The Microsoft Cloud Blog. [accessed 2025 Jun 25]. https://www.microsoft.com/en-us/microsoft-cloud/blog/2024/09/20/accelerating-the-addition-of-carbon-free-energy-an-update-on-progress/.

[38] Skidmore Z. 2024 Nov 6. AWS reaffirms commitment to nuclear data center despite regulatory rejection. [accessed 2025 Jun 25]. https://www.datacenterdynamics.com/en/news/aws-reaffirms-commitment-to-nuclear-data-center-despite-regulatory-rejection/.

To forecast power demand and account for the constraints identified in previous sections, our market analysis leverages:

1. **A proprietary data center database that forecasts future demand:** We differentiate between announced and actual capacity, as not all announced projects proceed to construction. Certain regions have proven inherently more favorable for data center development and are likely to continue.
2. **WattTime regions:** These are used as a proxy for identifying electrical transmission constraints and highlighting areas that show significant projected demand growth from data centers (see **figure 7**). This provides a **conservative basis** for estimating potential demand for NG+CCS to meet the electricity requirements of future data centers.

### Natural gas-fired generation fleet analysis

It is critical to select natural gas-fired power facilities that have the right characteristics for adding CCUS as a retrofit. We sourced information from multiple public and government databases to fully account for all potential sites and then down-selected for facilities that would likely have the appropriate characteristics. The methodology we used is documented further in *Appendix B*.

### CCS infrastructure analysis

Storing and utilizing $CO_2$ has been a speculative topic of discussion for many decades. $CO_2$ transportation and storage infrastructure is one of the key points of development required for full CCUS adoption. Our analysis assumes $CO_2$ can be stored using one of the following methods:

1. Building a new Class VI well for geological storage[39] and receiving a permanency credit under 45Q,
2. Contracting with an existing $CO_2$ pipeline and receiving a permanency credit under 45Q due to a connected Class VI well, or
3. Contracting with a proposed pipeline connected to a Class VI well.

We ultimately excluded the last option from the proposed locations of interest due to our final assessment that no proposed pipelines will reach final investment decisions, or final permit decision on any connected Class VI wells, before 2030. Proposed changes to 45Q indicate that Class II wells and EOR are potentially preferred candidates. We considered this, but did it not substantially alter our conclusions or results.

## Results

**Based on our analysis, NG+CCUS has a promising future as a reliable, low-carbon power source for the growing data center sector.** We uncovered a clear pattern when comparing sites that plan to collect and transport $CO_2$ via pipeline to a storage site versus sites that plan to develop storage infrastructure nearby in the form of wells. Modeling shows a strong preference for sites that plan to develop storage infrastructure nearby in the form of wells. This is due to the low projected storage costs for many of these sites and a wish to avoid the risks associated with large-scale $CO_2$ pipeline deployment.

[39] Cao R, Miller Q, Davidson C, Gallin W, Reidel S, Jiao Z, McLaughlin J, Nienhuis E, Schaef H. 2024. Gigaton commercial-scale carbon storage and mineralization potential in stacked Columbia River basalt reservoirs. International Journal of Greenhouse Gas Control. 137:104206. doi:10.1016/j.ijggc.2024.104206.

## Proximity to $CO_2$ collection infrastructure

The existing infrastructure for $CO_2$ collection does not have significant overlap with data center deployment locations. But unique situations exist where a region with new data center demand that is currently an electricity exporter (e.g., Dallas-Fort Worth) could switch to being a net importer of electricity from a region with electricity-generating potential and $CO_2$ collection infrastructure (e.g., Houston).

## Proximity to $CO_2$ storage geology

Further positive developments include upcoming changes to EPA regulations, which have already reduced the Class VI well permitting timeline from six to eight years to under four years, with a target of two years for new applications. Furthermore, states with primacy (e.g., Louisiana, North Dakota, West Virginia, Wyoming) or those seeking it (e.g., Arizona, Texas) may experience even shorter timeframes. Consequently, wells that are already approved offer an advantage, moving project timelines from four years to less than two years. However, they do not provide a substantial timing benefit due to anticipated improvements in the standard permitting process. We tracked Class VI well permits and granted applications and found a high degree of overlap with data center demand locations. Ultimately, this shows that the market for $CO_2$ storage infrastructure is mostly on track with responding to projected data center demand and timing. One notable exception is the East Coast, which includes the largest new demand region in Virginia.

While we considered overall $CO_2$ collection and storage infrastructure to be less of a primary constraint in the model, this assumption relies on the ability to construct short-leg pipelines with relatively low public opposition. While often feasible for natural gas pipelines, $CO_2$ pipeline development can face more significant community opposition in some areas, complicating deployment. For most regions, planned data center capacity can be fully met by power facilities connected to $CO_2$ collection and storage infrastructure options. That is, if buyers are willing to pay a green premium, intrastate pipelines do not face major public opposition, and Class VI well approval continues to improve.

## Strategic opportunities in emerging data center markets

### United States

Many regions possess power generation assets that are suitable for carbon capture retrofits, but a lack of projected transmission capacity to areas with data center demand presents a significant challenge. This geographical mismatch often means the lowest-cost decarbonization projects are economically unviable.

Even within regions exhibiting high data center demand, several critical exclusions emerged during our analysis:

1. **Reliance on facilities that only use natural gas turbine (NGT) technology:** Sites exclusively utilizing NGT technology frequently demonstrated an inability to achieve carbon capture costs below US$30/MWh, due to high $CO_2$ emissions relative to MWh production (i.e., low efficiency). Achieving costs below this cost threshold is crucial for economic viability under current incentive structures. Newer, higher-efficiency facilities are more likely to achieve this cost threshold.

2. **Constrained electrical transmission infrastructure:** In some regions, existing electrical transmission bottlenecks significantly hinder the integration of new low-carbon power sources.
    a. In some places with high additional demand, this issue is becoming increasingly urgent as the deployment of new transmission infrastructure has slowed dramatically.[40] New capacity in these regions will be advantaged.
    b. Meanwhile, the opposite is true for many regions that are not experiencing high additional demand and are already well served. These regions are continuing to build further electrical transmission capacity.[41,42,43] However, without integrating more transmission capacity to high-demand regions, additional capacity is likely to be disadvantaged.

Existing power plant locations that are suitable for new build capacity in the regions of proposed data center deployment must have the following characteristics:

- Proximity to customers that can guarantee long-term offtake agreements at a premium, up to an additional US$30/MWh (to account for inflation, contingency, first-of-a-kind issues, permitting delays, and policy delays)
- Available electrical transmission capacity in an unregulated market
- Available natural gas capacity
- On-site or adjacent $CO_2$ storage options, or nearby $CO_2$ transportation infrastructure, with capacity greater than 300 MW for self-developed infrastructure

Regions of interest for new data centers are mostly aligned with low-cost NG+CCUS. Approximately 63% of future data center demand can support decarbonizing power generation through CCUS deployments at existing facilities (61 sites). This assumes that these facilities will qualify for the 45Q tax credit.

While challenges such as limitations in electrical transmission capacity, complexities in regulated markets, and integration considerations (e.g., mitigating sudden load disconnects and coordinating backup power switching with grid operators) exist, these are surmountable.

**Illinois**

Illinois has significant potential to be a leading state in the large-scale deployment of CCUS. The necessary conditions are largely in place, with the exception of political sentiment. Notably, opposition to $CO_2$ transport and infrastructure has emerged, even from organizations that support

[40] Shreve N, Zimmerman Z, Gramlich R. 2024. Fewer New Miles: The US TransmissionGrid in the 2020s. Americans for a Clean Energy Grid. [accessed 2025 June 25]. https://cleanenergygrid.org/wp-content/uploads/2024/07/GS_ACEG-Fewer-New-Miles-Report-July-2024.pdf
[41] PJM. 2025 Feb 26. PJM Board Approves New Transmission Projects To Support Grid Reliability | PJM Inside Lines. [accessed 2025 Jun 25]. https://insidelines.pjm.com/pjm-board-approves-new-transmission-projects-to-support-grid-reliability/.
[42] Schulz J. 2025. Wisconsin to see $4.1B investment from 6 new transmission projects. [accessed 2025 Jun 25]. https://www.wpr.org/news/wisconsin-to-see-4-1b-investment-from-6-new-transmission-projects
[43] Invenergy. 2025. Grain Belt Express Awards $1.7B to U.S. Contractors Quanta and Kiewit to Build Largest Transmission Line in U.S. History. [accessed 2025 Jun 25]. https://invenergy.com/news/grain-belt-express-awards-1-7b-to-u-s-contractors-quanta-and-kiewit-to-build-largest-transmission-line-in-u-s-history

natural gas pipelines or advocate for decarbonization.[44] Similar opposition exists for natural gas pipelines, for fossil-fuel based power systems generally, and for electrical transmission infrastructure, which would be necessary to import renewables from neighboring low-cost regions.

**Georgia**
Forecasted demand within the Atlanta area could be met by various facilities located throughout the surrounding metropolitan area. Large-scale power facilities may provide opportunities for economies of scale. However, the regulated market structure may present barriers to entry, unless accessed through the utilities.

**Texas—Dallas-Fort Worth and Houston**
Despite numerous announcements for new data centers in Texas, a relatively limited number are currently scheduled to commence construction by 2030. This creates a window of opportunity for strategic alignment with low-carbon power solutions.

The Houston metropolitan area is experiencing significantly increased electrical demand, and the city's current transmission constraints will become even more pronounced.[45] This presents as slightly more favorable CCUS economics, potentially rendering Houston more competitive than the Dallas-Forth Worth area to service new demand within ERCOT, provided natural gas supply limitations can be addressed and existing $CO_2$ infrastructure can be leveraged. The Dallas-Fort Worth region, conversely, could rapidly rival Houston's CCUS potential with swift development of dedicated $CO_2$ infrastructure. This infrastructure could include nearby Class VI wells or pipeline development to western or southern Texas.

A key advantage for both Houston and Dallas-Fort Worth lies in the existing prevalence of Class II injection wells, which are closely aligned with Class VI well requirements. Texas has applied for primacy, and significant transmission. If Class II wells can successfully be converted, storage infrastructure may be available before data center construction begins. Therefore, both regions warrant immediate consideration for substantial, planned data center demand.

**Texas—Houston only**
The limited number of sites automatically selected in this area is primarily a consequence of an artificial constraint imposed by our automated methodology, which restricts power generation to within its respective balancing area. However, removal of this constraint is difficult to automate and is still done manually. When system reliability benefits were fully accounted for—specifically, the potential reduction in transmission requirements into the heavily loaded Houston area, which is highly probable as mentioned in the previous section—then significantly more facilities emerged as competitive. These facilities are often closer to existing $CO_2$ infrastructure, and surpass locations within the Dallas-Fort Worth area in terms of risk-adjusted economics. Furthermore, data center deployment announcements extending past 2030 indicate several GW of additional demand in Houston alone, pointing to substantial future opportunities for this region.

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[44] Adams A. 2024. After years of controversy, state pauses $CO_2$ pipeline construction, for now. [accessed 2025 Jun 25]. NPR Illinois. https://www.nprillinois.org/health-harvest/2024-07-18/after-years-of-controversy-state-pauses-co2-pipeline-construction-for-now.
[45] Hao C. 2025 Apr 24. CenterPoint: Houston metro could need 50% more electricity by 2031 at peak times. Houston Chronicle. [accessed 2025 Jun 25]. https://www.houstonchronicle.com/business/energy/article/houston-electricity-demand-growth-20281415.php.

In this region, we have identified numerous facilities that fall within a narrow margin of overall CCUS cost. This suggests that factors beyond raw economic modeling could play a decisive role. Established familiarity and expertise in carbon capture technology deployment could provide a substantial competitive advantage for generators in this space, effectively turning what looked to be marginally competitive opportunities into viable projects.

**Virginia**

Virginia stands as the preeminent location for data center deployment, a trend projected to continue into the foreseeable future. The concentration of demand in Virginia is increasingly challenged by constrained electrical generation and transmission capacity. This is leading to mounting reliability concerns regarding the state grid's ability to meet escalating power requirements for data centers.[46]

A significant limiting factor in Virginia is the natural gas pipeline infrastructure. Historical opposition to natural gas pipeline development continues to limit natural gas availability, with no committed timelines for new pipeline announcements that could alleviate current bottlenecks.[47]

Despite these infrastructure challenges, sites in Virginia could prove well-suited for CCUS. Geological characterization suggests that the eastern portion of the state could provide low-cost, high-quality $CO_2$ storage in places like the Norfolk basin or continental margin rocks (**figure 8**). However, the lack of existing geological characterizations would add risk to Virginian projects. To date, no Class VI well permit applications are in process, and the lack of oil and gas accumulations means data are scarce and both drilling rigs and experienced workforce are limited.

The absence of pre-vetted $CO_2$ storage sites places a substantial burden on any first-of-a-kind CCUS project in the region. Without significant support from state, local, or federal government, this barrier hobbles potential data center operators that need to secure low-carbon electricity at a reasonable price point. For example, the state could strategically invest in geological characterization and demonstration to mitigate the burden for developers. Virginia would also benefit from the additional jobs, projects, and revenues that could follow. Specifically, developing $CO_2$ storage infrastructure in the state could attract nearly one-third of all prospective NG+CCUS opportunities to Virginia. This highlights a clear opportunity for public-private partnership to unlock significant decarbonization potential.

[46] Gooding M. 2025 Mar 20. Virginia narrowly avoided power cuts when 60 data centers dropped off the grid at once. [accessed 2025 Jun 25]. https://www.datacenterdynamics.com/en/news/virginia-narrowly-avoided-power-cuts-when-60-data-centers-dropped-off-the-grid-at-once/.

[47] Busse M. 2025. Transco plans another natural gas pipeline project for Virginia. Cardinal News. [accessed 2025 Jun 25]. https://cardinalnews.org/2025/05/13/another-transco-pipeline-project-planned-for-virginia/.

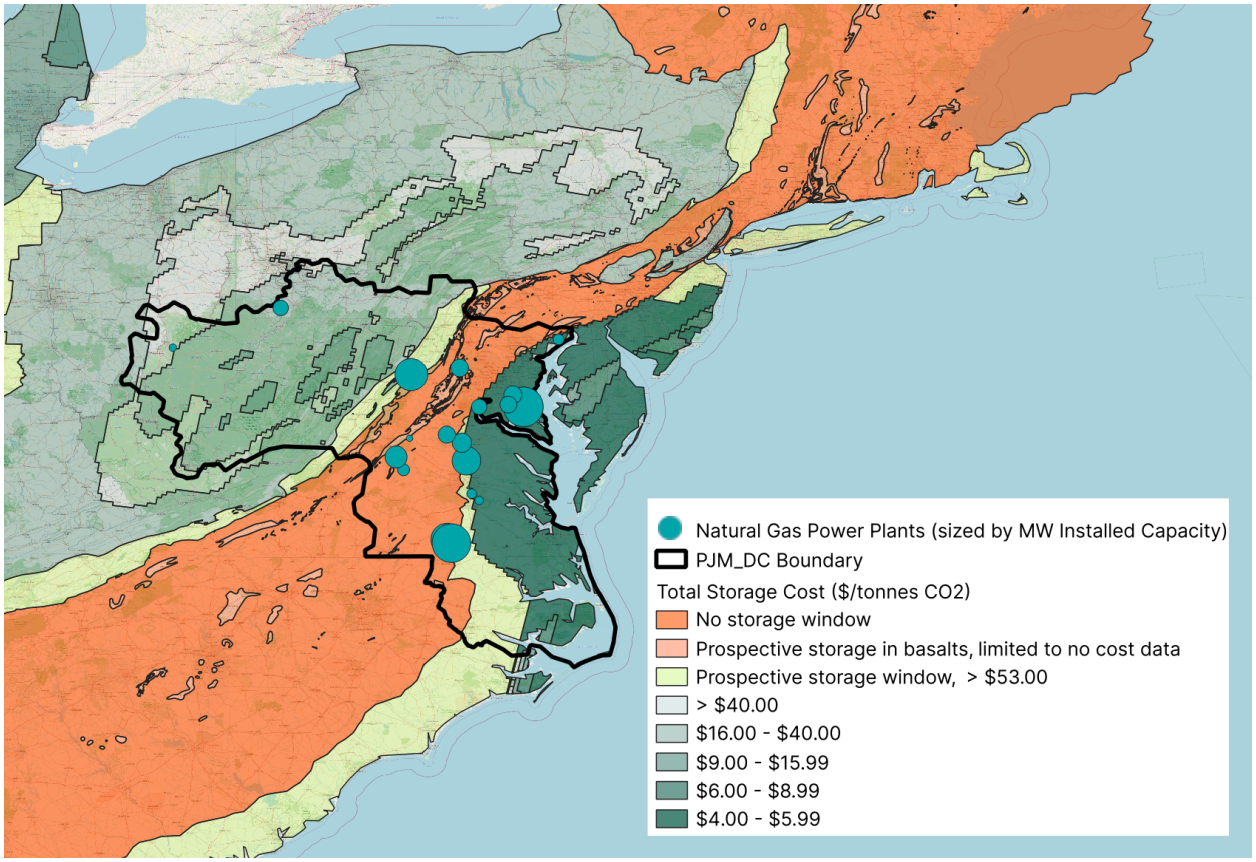



**Figure 8**. Natural gas-fired power facilities within the PJM-DC boundary and $CO_2$ storage costs. Source: Carbon Direct, based on data from Livermore Lab Foundation[48] and EIA.[49]

## Canada

In Canada, current data center development is limited until 2030, but recent announcements could rapidly change this.[50, 51]

Today, approximately 350 MW of data center demand is concentrated in Quebec. Quebec's lone NGCC cogeneration facility is also situated atop a saline aquifer. New data center demand in Quebec represents less than half of this facility's total capacity. This facility is a promising future candidate, as further growth is expected, and it would serve as an optimal deployment site. Currently, this site represents the sole development possibility in Canada before 2030.

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[48] Livermore Lab Foundation. c2025. Roads to Removal – Options for carbon dioxide removal in the US. [accessed 2025 Jun 25]. https://roads2removal.org/.
[49] US Energy Information Administration. 2025. Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860). [accessed 2025 Jun 25]. https://www.eia.gov/electricity/data/eia860m/.
[50] Skimore Z. 2024 Dec 10. Mr. Wonderful backs off-grid power venture for Alberta data center. [accessed 2025 Jun 25]. https://www.datacenterdynamics.com/en/news/mr-wonderful-backs-off-grid-power-venture-for-alberta-data-center/.
[51] The Canadian Press. 2025 May 28. Bell announces plans to open six AI data centres in B.C. as part of Bell AI Fabric. BNN Bloomberg. [accessed 2025 Jun 25]. https://www.bnnbloomberg.ca/business/company-news/2025/05/28/bell-announces-plans-to-open-six-ai-data-centres-in-bc-as-part-of-bell-ai-fabric/.

More than 1.2GW of data center capacity has been announced in Alberta, encompassing seven suitable NGCC sites, but with planned start dates post-2030. With the low cost of natural gas, existing $CO_2$ infrastructure, and favorable political environment, demand should be readily met by existing locations. Additionally, Alberta demonstrates ideal characteristics for NG+CCUS deployment including existing mobilized rigs, a best-in-class and experienced workforce, and abundant natural gas at low pricing.

## Conclusion

The rapid expansion of data centers and associated electrical demand requires robust and reliable decarbonization strategies. NG+CCUS represents a viable path forward in key markets, offering dispatchable, reliable power that aligns with the high-density, high-reliability requirements of data centers. Furthermore, it supports the geographic clustering needs of data centers, while simultaneously lowering emissions. In most regions it appears to be the only source of power that can meet data centers' requirements.

We evaluated every natural gas-fired generator across the US and Canada, assessing its suitability to meet the potential data center power demand based on **timing, reliability, emissions, and cost**.

Regarding **timing**, natural gas-fired generation has several advantages: it is able to leverage existing grid infrastructures to meet data centers' rapid deployment requirements, it can move quickly through the interconnection queue, and it can supply reliable power. In terms of **reliability**, natural gas-fired generation can meet data centers' stringent demands by inherently avoiding intermittency issues, a demand that solar or wind power with battery storage cannot feasibly meet. From an **emissions** perspective, our LCA incorporates reliability-adjusted carbon intensities (EACIs) for direct comparison, and demonstrates that NG+CCUS has lower effective emissions in the PJM region than solar power with 4-hour battery storage. We expect this to be similar for all regions, if upstream methane leaks are within the national average. Lastly, our market analysis focused on CCUS opportunities for natural gas-fired generation, allowing us to assess **cost** impacts across various factors, including project-specific and policy support considerations.

Strategic opportunities for NG+CCUS are plentiful in most key regions. These opportunities are found where there is a good match between existing electrical transmission infrastructure, low-cost $CO_2$ storage/utilization locations, and data center locations. This is particularly true where existing natural gas, power, and $CO_2$ infrastructure can speed deployment. Ultimately, NG+CCUS represents a promising pathway to decarbonizing the electricity demand of data centers while meeting the need for reliable power.

## Appendix A: Life cycle assessment details

It is important to understand the impact of adding CCS technology to an NGCC cogeneration facility, in terms of the CI of the electricity and steam it produces. This information is valuable on its own, but also helps us compare NG+CCS to other low-carbon electricity generation technologies. We considered three NGCC cogeneration models with varying heat rates:

1. A new-build, state-of-the-art NGCC cogeneration facility built with CC;
2. An existing NGCC cogeneration facility where CC is added as a retrofit; and
3. A baseline with an intermediate heat rate.

In each model, captured and compressed $CO_2$ is stored and not used as an intermediate product (e.g., for chemical synthesis or EOR). Additional details on our LCA are shown in **figure 9**, **figure 10**, **table 4**, and **table 5** below.

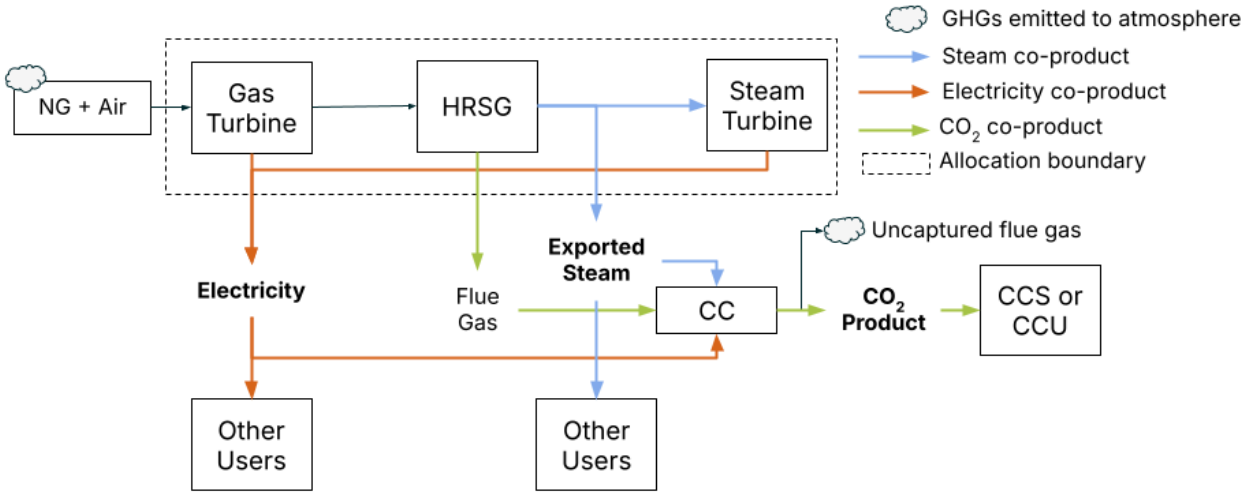



**Figure 9.** System boundary. If greenhouse gases (GHGs) are emitted to the atmosphere during a process step, that step is marked with a cloud icon. The allocation boundary is indicated by a dotted line. Products are tracked via different color lines: blue for steam co-product, orange for electricity co-product, and green for carbon dioxide ($CO_2$) co-product. Compressed $CO_2$ is only considered a product in the carbon capture and utilization (CCU) case. Note: CC = carbon capture, CCS = carbon capture and storage, HRSG = heat recovery steam generator, NG = natural gas. Source: Carbon Direct.

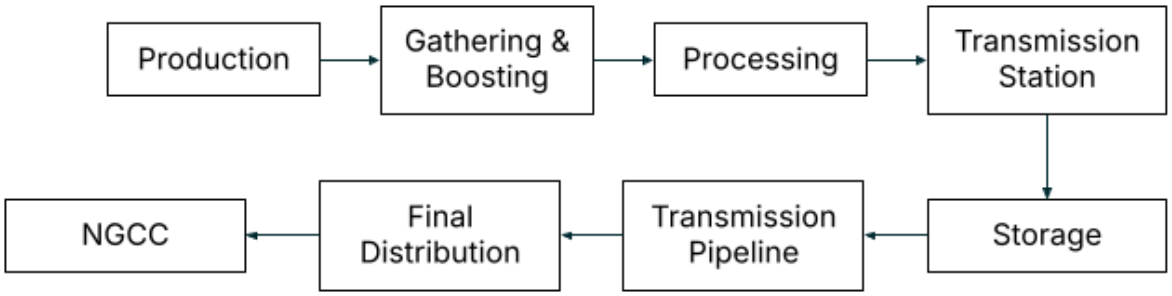



**Figure 10.** Detail of processes considered for the natural gas supply chain. All emissions for each process are considered for this study, including greenhouse gas (GHG) emissions and non-GHG emissions. Non-GHG

emissions include pollutants tracked in the EPA's TRACI tool[52] that have ecotoxicity, human health, and photochemical oxidation impacts (e.g. non-GHG hydrocarbons, volatile organic compounds, etc.).

**Table 4.** Baseline design parameters and assumptions for the NGCC facility without CC

| Parameter | Value and units |
|---|---|
| NGCC auxiliaries electricity consumption | 2% of gross capacity |
| Carbon wt% in natural gas | 0.724 |
| Lower heating value (LHV) natural gas | 0.0203 MMBTU/lbm |
| LHV net plant efficiency | 51.9% |
| Heat rate | 6,570 BTU LHV/kWhe |
| Steam turbine exergetic efficiency | 50.3% |

**Table 5.** Design parameters/assumptions for the NGCC facility with CC

| Parameter | Value and units |
|---|---|
| NGCC auxiliaries electricity consumption | 2% of gross capacity |
| CC power draw | 0.8% of gross capacity |
| CC steam draw (exergy basis) | 2.07 MMBTU/metric tonne $CO_2$ product |
| Steam exported to non-CC customers (base case, exergy basis) | 0 MMBTU/hr |
| $CO_2$ compression power draw | 4% of gross capacity |
| Foregone electricity generation from CC steam draw | 11.4% of gross capacity |
| $CO_2$ capture rate | 97.5% |
| $CO_2$ product purity | 99.99 wt% $CO_2$ |
| LHV net plant efficiency | 43.2% |
| Heat rate | 7,892 BTU LHV/kWhe |

## Impact categories assessed

For the NGCC + CC system, we considered GHG emissions/climate change, ecotoxicity (freshwater, marine, and terrestrial), human toxicity (carcinogenic and non-carcinogenic), and photochemical oxidation potential.

[52] US Environmental Protection Agency. 2015 Dec 17. Tool for Reduction and Assessment of Chemicals and Other Environmental Impacts (TRACI). [accessed 2025 Jun 25]. https://www.epa.gov/chemical-research/tool-reduction-and-assessment-chemicals-and-other-environmental-impacts-traci.

When comparing against NGCC without CC, NGT, nuclear, wind + BESS, and solar + BESS, we considered only GHG emissions/climate change. In general, when conducting a comparative LCA, it is advisable to compare several impact categories. However, this consideration is out of scope of this particular analysis. Reducing GHG emissions is a primary motivator for installing CC systems, so this comparison focuses only on this impact category. Future work should consider other impact categories of the NGT, nuclear, wind + BESS, and solar + BESS systems.

If the environmental impact of an input is <1% of the total impact of the system, we did not include it in the analysis. We utilized TRACI v2.2 for impact characterization factors, except for global warming potential (GWP). GWPs are taken from the latest IPCC AR6.[53]

## Emission factors and data representativeness

Natural gas is by far the largest single input by embodied emissions into the system. We took care to ensure that the emission factor(s) utilized for this input were therefore not only high-quality but also temporally and spatially relevant to the system. Data for upstream emissions (wellhead to the NGCC+CC facility) of the natural gas production system are broken down by type (i.e., conventional, tight, and shale) and basin (15 basins considered) in a 2025 NETL report.[54] We cleaned and synthesized this report's data for this study. Any mix of natural gas by type and basin may be utilized by the model.

Makeup water, sodium hydroxide, and nitrogen gas (for occasional system sparging, sealing, and other miscellaneous uses) are the only other material inputs to the system. Each of their environmental impacts, however, fall outside of the cut-off criteria described above. Similarly, NGCC plant material and construction impacts are well outside of the cut-off criteria, accounting for less than 0.1% of total impacts.[55]

The CC system is proprietary and employs a proprietary, undisclosed solvent with an undisclosed composition and replenishment rate. Emissions of this solvent to land, air, and water may have environmental impacts, especially if the replenishment rate is high. However, we did not consider any impacts associated with the production, use, and end-of-life of this solvent in this study. Future work should focus on quantifying these impacts, if there are any.

## Allocation procedures

A central goal of this study is to estimate the CI of electricity and steam products leaving the NGCC+CC system. Therefore, system expansion is not appropriate here. We followed subdivision wherever possible. The NGCC system includes a NGT and a heat recovery steam generation (HRSG) system to generate steam. Some of that steam is siphoned off to the CC train, some may be sold to third parties, and some may be used to generate electricity via a steam turbine. The net

[53] The Intergovernmental Panel on Climate Change. 2023. Sixth Assessment Report — IPCC. [accessed 2025 Jun 25]. https://www.ipcc.ch/assessment-report/ar6/.
[54] Khutal H, Kirchner-Ortiz K, Blackhurst M, Willems N, Matthews HS, Rai S, Yanai G, Chivukula K, Priyadarshini N, Hoffman H, et al. 2024. Life Cycle Analysis of Natural Gas Extraction and Power Generation: U.S. 2020 Emissions Profile. National Energy Technology Laboratory (NETL), Pittsburgh, PA, Morgantown, WV, and Albany, OR (United States) Report No.: DOE/NETL-2024/4862. [accessed 2025 Jun 25]. https://www.osti.gov/biblio/2481535.
[55] US Department of Energy. 2024. GREET. Energy.gov. [accessed 2025 Jun 25]. https://www.energy.gov/eere/greet.

electricity produced by the gas and steam turbines may be exported to the CC train or to other users.

The allocation boundary is shown in **Figure 9**. ISO standards require that if allocation is followed, it should be based on an underlying physical relationship between the products, if possible. A key function of a cogeneration facility is to convert as much of the chemical energy in the natural gas feedstock to exergy as possible, in the form of electricity and steam. Some of this exergy is lost in the flue gas, some is contained in exported steam and electricity, and some is lost due to system inefficiencies. However, exergy is a physical property common to both products that relates directly to the underlying function of the NGCC system. Therefore, allocation by exergy is an appropriate and defensible method for this system.

## Major assumptions

- The NGCC+CC facility is located in the US.
- The NGCC+CC facility consumes only domestically-produced natural gas.
- Negligible quantities of non-$CO_2$ species are emitted to the atmosphere from the CC train. In reality, some non-$CO_2$ species will be released; the environmental impacts of such pollutants should be more carefully evaluated once the plant is operational.
- In the base case, the mix of natural gas entering the NGCC facility is the US weighted production mix across all basins.
- The input natural gas is a mix of methane and other gases. It has a lower heating value of ~47.1 MJ/kg and a carbon wt% of ~72.4%.
- In the base case, on-spec steam production from the HRSG occurs instantly when the NGCC system ramps up. Subsequently, the CC train achieves its optimal operating conditions instantly. These assumptions collectively mean that the CC train will have 100% uptime whenever the NGCC is operational.
- The heat rate of the facility without the CC system is 6,598 BTU/kWh, reflecting an NGCC efficiency of ~51.7% (kWh LHV of input natural gas divided by kWh of net electricity produced in the absence of a CCS system).
- Power draw of auxiliaries in the NGCC facility are proportional to the nameplate capacity to other reported values in the literature.
- 110 kWh of electricity is required to compress one metric tonne of the $CO_2$ product to pipeline specifications (average of estimates from several sources).[56, 57, 58]
- The steam turbine has an exergetic efficiency of ~50.3%.
- The CC facility operates for at least 72 hours per year. For this design case, 72 hours is the operating time required to produce and capture >18,750 metric tonnes of $CO_2$, making the facility eligible for either storage or utilization credits from 45Q.

[56] McKaskle R, Fisher K, Jones R, Frailey S. 2012. Design, Startup, and Operation of a 50 MWe $CO_2$ Sequestration System. Conference Proceedings of the Eleventh Annual Carbon Capture, Utilization, and Sequestration Conference. [accessed 2025 Jun 25]. https://trimeric.com/assets/mckaskle_wed_351.pdf
[57] Schmitt T, Leptinsky S, Turner M, Zoelle A, White CW, Hughes S, Homsy S, Woods M, Hoffman H, Shultz T, et al. 2022. Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity. National Energy Technology Laboratory (NETL), Pittsburgh, PA, Morgantown, WV, and Albany, OR (United States) Report No.: DOE/NETL-2023/4320. [accessed 2025 Jun 25]. https://www.osti.gov/biblio/1893822.
[58] McCollum DL, Ogden JM. 2006 Oct 1. Techno-Economic Models for Carbon Dioxide Compression, Transport, and Storage & Correlations for Estimating Carbon Dioxide Density and Viscosity. [accessed 2025 Jun 25]. https://escholarship.org/uc/item/1zg00532.

- ELCC factors for each electricity generation technology are taken from PJM's current and future projections. Therefore, this facility's ELCC is compared to other generation resources in PJM's territory. ELCCs in other independent system operators (ISOs) will be different than PJM's due to differences in climate, regulations, and grid mix.[59]
- BESSs operate for 300 charge-discharge cycles per year, operate for 10 years, and have a round-trip efficiency of 88%.
- New-build NGCC facilities have a heat rate of 5,750 BTU/kWh (without CC). This base heat rate is assumed for the case where the CC train is co-built with a new-build, state-of-the-art NGCC facility.
- The existing fleet of NGCC facilities (without CC) in the US has an average heat rate of 7,478 BTU/kWh.[60] This heat rate is assumed for the case where the CC train is a retrofit on an existing plant.

## Life cycle inventory (LCI)

This analysis is not based on a currently existing and operating NGCC facility. The entirety of the flue gas from the NGCC is assumed to enter the CC system, which is designed to capture 97.5% of incoming $CO_2$. We calculated exergies of the flue gas and input steam from the HRSG using a reference temperature of 298.15 K (77°F) and pressure of 1 atm (14.7 psia).

We took upstream natural gas emissions from production, gathering, boosting, processing, transmission, storage, and pipeline distribution from basin-specific estimates in a 2025 NETL report.[61] This study uses a production-weighted average for emissions, resulting in a methane leakage rate throughout the system of 0.75% (energy basis or 0.71% on a mass basis). Methane leakage rates from different basins vary from 0.48% (Gulf of Mexico, offshore production) to 4.00% (Uinta basin, conventional gas production) on a mass basis. Roughly 39% of US natural gas is sourced from shale gas in the Appalachian basin, which has a methane leakage rate of ~0.58% (mass basis).

Our operating parameters for the NGCC are fully modelled and assumed. A baseline NGCC, a new-build NGCC, and a representative NGCC were developed based on literature models for NGCC facilities as well as existing US Energy Information Administration (EIA) data. The heat rate of the NGCC facility is the only parameter that varies between each NGCC scenario and is meant to capture all the minor variations between plant size and age.

[59] California ISO. 2021 Jun 24. Effective Load Carrying Capability (ELCC)Study Results for Demand Response (DR) Resources. Stakeholder Web Conference. [accessed 2025 Jun 25]. https://www.caiso.com/Documents/Presentation-ELCCStudyResults-DemandResponseResources-Jun24-2021.pdf.
[60] US Energy Information Administration. SAS Output. [accessed 2025 Jun 25]. https://www.eia.gov/electricity/annual/html/epa_08_02.html.
[61] Khutal H, Kirchner-Ortiz K, Blackhurst M, Willems N, Matthews HS, Rai S, Yanai G, Chivukula K, Priyadarshini N, Hoffman H, et al. 2024. Life Cycle Analysis of Natural Gas Extraction and Power Generation: U.S. 2020 Emissions Profile. National Energy Technology Laboratory (NETL), Pittsburgh, PA, Morgantown, WV, and Albany, OR (United States) Report No.: DOE/NETL-2024/4862. [accessed 2025 Jun 25]. https://www.osti.gov/biblio/2481535.

GHG-only LCIs for nuclear power plants, NGCC power plants, NGT power plants, utility-scale PV facilities, utility-scale wind turbines, and BESS were taken from a variety of sources, including the 2024 GREET1 model,[62] the NREL electricity LCA harmonization studies,[63] and NETL reports.[64, 65]

Most of the data is from 2020 and is either measured, modelled, or reported. Some of the older datasets include LCI data on nuclear power plants.

## Life cycle impact assessment

For the NG+CCS case ($CO_2$ not a product), total system emissions are ~53 metric tonnes $CO_2e$ per hour. The allocation of these emissions to electricity and steam products are shown below in **figure 11**. Note that this figure does not display CIs of each product stream. Not only is more exergy being exported in each case, but less electricity is being produced as well. As steam export rates increase, emissions allocated to electricity drop significantly.

Note that in the NG+CCU case ($CO_2$ considered a product), total system emissions do not change, remaining at ~53 metric tonnes of $CO_2e$ per hr. However, they are allocated to more products. **Figure 12** shows the breakdown of system emissions allocated to each product. Note that this figure does not display CIs of each product stream.

[62] Argonne National Laboratory. 2025 May 23. Argonne GREET R&D Model. [accessed 2025 Jun 25]. https://greet.anl.gov/.
[63] The National Renewable Energy Laboratory. 2025. Life Cycle Assessment Harmonization. [accessed 2025 Jun 25]. https://www2.nrel.gov/analysis/life-cycle-assessment.
[64] Schmitt T, Leptinsky S, Turner M, Zoelle A, White CW, Hughes S, Homsy S, Woods M, Hoffman H, Shultz T, et al. 2022. Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity. National Energy Technology Laboratory (NETL), Pittsburgh, PA, Morgantown, WV, and Albany, OR (United States) Report No.: DOE/NETL-2023/4320. [accessed 2025 Jun 25]. https://www.osti.gov/biblio/1893822.
[65] Khutal H, Kirchner-Ortiz K, Blackhurst M, Willems N, Matthews HS, Rai S, Yanai G, Chivukula K, Priyadarshini N, Hoffman H, et al. 2024. Life Cycle Analysis of Natural Gas Extraction and Power Generation: U.S. 2020 Emissions Profile. National Energy Technology Laboratory (NETL), Pittsburgh, PA, Morgantown, WV, and Albany, OR (United States) Report No.: DOE/NETL-2024/4862. [accessed 2025 Jun 25]. https://www.osti.gov/biblio/2481535.

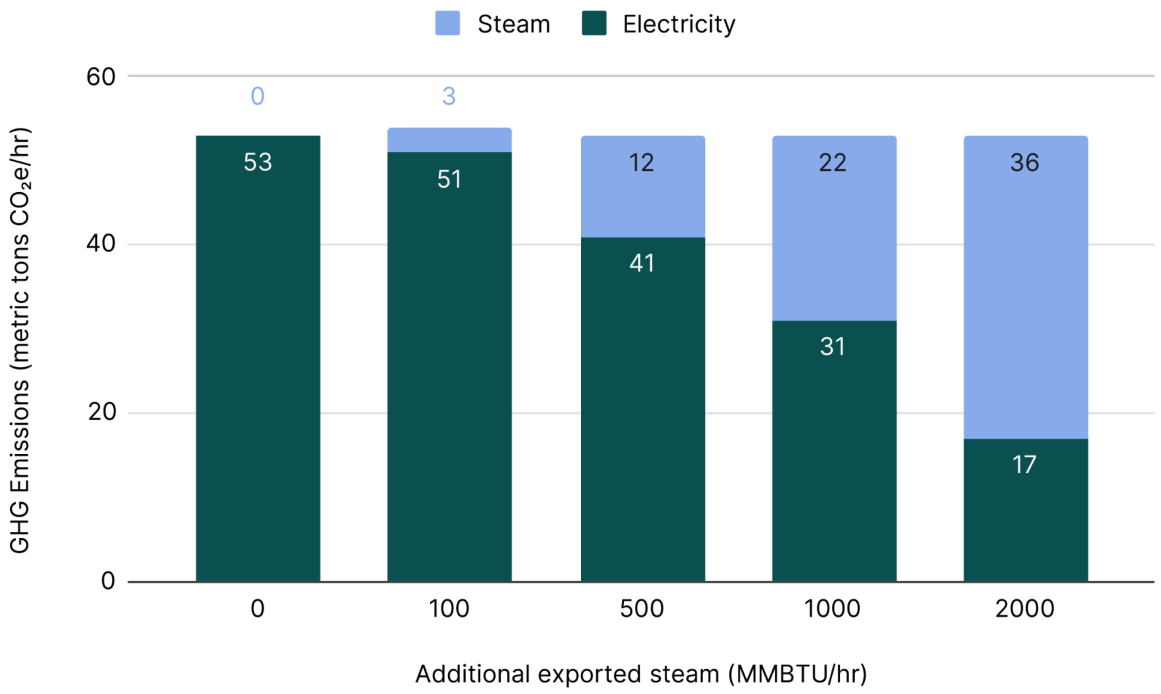



**Figure 11.** Systemwide emissions allocated to electricity and steam exported to other users as a function of steam exported to other users. Compressed $CO_2$ is not considered a product. Source: Carbon Direct.

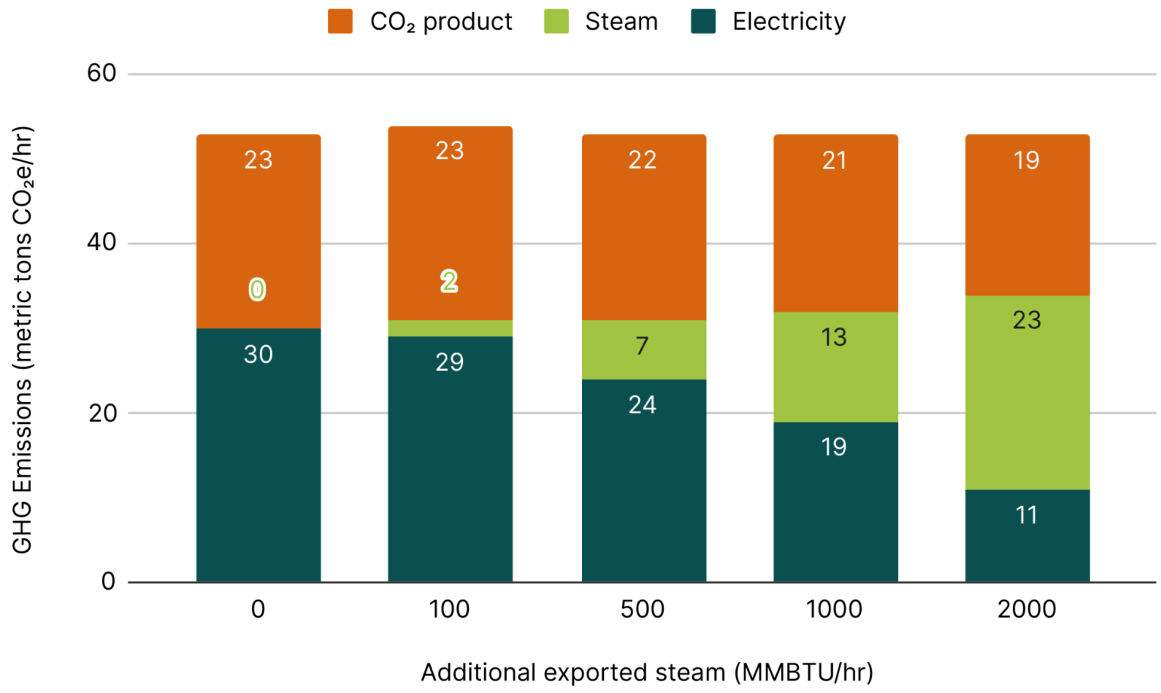



**Figure 12.** Systemwide GHG emissions allocated to each product stream as a function of increasing steam export to other users.

## Other impact categories

Other impact categories we also considered are shown in **Table 6**. Total unallocated life cycle impacts for each category, and impacts per functional unit for each product for two cases (0 steam export and 1,000 MMBTU/hr steam export) are included. We only displayed results for the case where the $CO_2$ is utilized as an intermediate product.

**Table 6**. Non-GHG impact categories considered in this study

| Impact category (units) | Unallocated, total life cycle impact | No steam export to non-CC users | 1,000 MMBTU/hr steam export to non-CC users | |
|---|---|---|---|---|
| | | Electricity ($MWh^{-1}$) | Electricity ($MWh^{-1}$) | Steam ($MMBTU^{-1}$) |
| FE (CTUeco) | 7.41E+04 | 1.30E+02 | 1.03E+02 | 3.03E+01 |
| ME (CTUeco) | 1.23E-01 | 2.15E-04 | 1.71E-04 | 5.02E-05 |
| TE (CTUeco) | 1.82E+03 | 3.19E+00 | 2.54E+00 | 7.45E-01 |
| HHC (CTUcancer) | 3.13E-04 | 5.48E-07 | 4.36E-07 | 1.28E-07 |
| HHNC (CTUnoncancer) | 1.81E-02 | 3.17E-05 | 2.52E-05 | 7.40E-06 |
| HHP (PM2.5e) | 3.42E+01 | 5.98E-02 | 4.76E-02 | 1.40E-02 |
| POF (kg $O_3$e) | 1.37E+04 | 2.39E+01 | 1.90E+01 | 5.58E+00 |

FE = freshwater ecotoxicity; CTU = comparative toxic units; ME = marine ecotoxicity; TE = terrestrial ecotoxicity; HHC = human health, cancer; HHNC = human health, non-cancer; HHP = human health, particulates; POF = photochemical oxidation formation

## Comparing to other generators

The CI of electricity produced in this product system is compared against that of electricity produced and exported to a grid in a NGT system, a nuclear power generator, and utility-scale wind or solar generating facilities with BESS. The functional unit for this comparison is "ELCC-adjusted MWh," which utilizes a generating technology's effective load carrying capacity (ELCC) to account for intermittency, resource downtime (for repair, maintenance, failures), and reliability (ability of a resource to generate electricity when called upon). Basing an analysis on ELCC-adjusted MWhs aims to capture the difference between "MWh of electricity" and "MWh of electricity when and where it's needed," which better reflects the core function of any electricity generating technology. These functional units can be used to calculate ELCC-adjusted carbon intensities (EACIs).

ELCC ranges were adapted from PJM's estimates through 2035. ELCCs for each electricity-generating technology vary based on geography, the grid mix, and weather-based variations. Results shown in this report should only be considered to apply to generators under PJM's service area.

Nuclear-derived electricity has the lowest EACI, reflecting its already low operational CI (no GHGs emitted during electricity generation) and its high ELCC. NGCCs' EACIs range between 560-602 kg $CO_2$e/MWh. Wind + 4-hr BESS EACIs range between 89-131 kg $CO_2$e/MWh. The EACI for Solar PV + 4 hr BESS is ~20% larger than the EACI for NGCC+CCS (modeled with this study's data). Solar cannot produce electricity at all hours of the day, while NGCC+CCS theoretically can; this phenomenon is captured in an EACI. Leveraging ELCC to effectively normalize emissions of an electricity-generating system by EACI is clearly demonstrated.

**Table 7.** Nominal CIs, ELCC ranges, and Average EACIs for different generators

| | **Nominal CI (kg $CO_2$e/MWh)** | **ELCC range (%)** | **Average EACI (kg $CO_2$e/MWh)** |
|---|---|---|---|
| Nuclear | 22 | 93–94 | 23 |
| NGCC | 476 | 79–85 | 577 |
| NGT | 670 | 61–78 | 962 |
| Wind + 4-hr BESS | 50 | 38–56 | 106 |
| Solar PV + 4-hr BESS | 76 | 38–56 | 160 |
| NGCC+CCS (this study) | 93 | 79–85 | 133 |

# Appendix B: Market analysis methodology

## Natural gas-fired generation fleet selection

### United States

This market analysis uses a list of power plant facilities in the continental United States, merging the US EIA's list of power plants[66] with the EPA's Greenhouse Gas Reporting Program (GHGRP) facilities[67] that are categorized as power plants. We excluded facilities with an annual reported $CO_2$ volume below 50,000 tonnes, assuming these would not achieve favorable economics (due to lower capital expenditure scaling per tonne with plant size). We spot checked and confirmed that plants were substantially either too small to be economical or were incompatible with commercial CC technologies. In our analysis, we carried the 45Q credit for 12 years from the start of a project, after which we found the operating expenses of a facility would push it significantly higher in the dispatch queue. In this case, another market mechanism would need to come into play in order to keep the facility dispatching before non-CCS plants.

### Canada

We sourced NGCC facilities and their annual $CO_2$ volumes from the Canadian Greenhouse Gas Reporting Program dataset,[68] and excluded facilities generating less than 50,000 tonnes.

### Natural gas-fired generation fleet in US (planned)

We identified existing and planned natural gas generators using the EIA Monthly Electric Generator Inventory.[69] We excluded all fuel types other than natural gas.

We calculated estimates of annual $CO_2$ for planned generators from the planned nameplate capacity in MW, multiplied by a capacity factor of 0.85 and emissions per MWh based on the prime mover type: 0.41 $tCO_2$/MWh for combined cycle systems, and 0.6 $tCO_2$/MWh for gas turbines. Some planned generators were added to existing facilities by matching ORIS Codes (EIA power plant identifiers) with their estimated annual $CO_2$ and added to the plant-level volume for processing, transportation, and storage cost estimates. Other planned generators represent new power plants, and are treated as separate facilities.

### Plants and generators

Starting with the EIA Monthly Electric Generator Inventory, we excluded units using fuel other than natural gas, and generators with single exhaust stacks from lower than 10MW nameplate capacity. We also excluded units marked as retired.

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[66] US Energy Information Administration. 2025. Power Plants. US Energy Atlas. [accessed 2025 Jun 25]. https://atlas.eia.gov/datasets/eia::power-plants/explore.
[67] US Environmental Protection Agency. 2015 May 18. Data Sets. [accessed 2025 Jun 25]. https://www.epa.gov/ghgreporting/data-sets.
[68] Government of Canada. Greenhouse Gas Reporting Program (GHGRP) - Facility Greenhouse Gas (GHG) Data - Open Government Portal. [accessed 2025 Jun 25]. https://open.canada.ca/data/en/dataset/a8ba14b7-7f23-462a-bdbb-83b0ef629823.
[69] US Energy Information Administration. 2025. Preliminary Monthly Electric Generator Inventory (based on Form EIA-860M as a supplement to Form EIA-860. February 2025 edition. [accessed 2025 Jun 25]. https://www.eia.gov/electricity/data/eia860m/.

EIA and EPA datasets use different identifiers for equipment such as steam turbines, gas turbines, combined cycle single shaft, combined cycle turbine, and steam parts. Published cross-walks[70] were used to identify feasible capture equipment, including situations where two or more turbines provide steam to a single steam unit. In particular, if several "CT" prime movers (turbine part) shared an EPA Emissions Unit ID with a "CA" prime mover (steam part) we combined the $CO_2$ of these CTs for the purposes of modeling capture costs. Otherwise, we combined CT units if they shared an operating date with a CA unit at the same plant.

We sourced annual $CO_2$ volumes for each generator or set of combined CA/CT pairs from the EPA's Clean Air Markets Program Data,[71] or estimated them from EIA monthly generator capacity factor publications, the nameplate capacity, and an emission factor specific to the generator type.

## Transportation methodology

We considered transportation by truck, rail, and pipeline. Ultimately, we excluded truck and rail for cost considerations. We considered pipelines that are a branch to a major $CO_2$ pipeline trunk, that connect to an existing saline aquifer basin that contains a Class II or Class VI well (for 0- and 2-year market targets), or that connect to any potential projected low-cost[72] saline aquifer basin (for 2030 targets).

We calculated distances from each facility to the nearest saline basin boundary using the NATCARB Atlas Saline Basin 10km Grid,[73] with designated Sole Source Aquifers[74] removed. We identified areas with Class II salt water disposal from Weingarten 2015.[75] Additionally, we sourced storage basins from Lawrence Livermore National Laboratory's 2023analysis.[76] We also used this analysis for potential alternative total cost assumptions.

[70] US Environmental Protection Agency. 2021 Jan 28. Power Sector Data Crosswalk. [accessed 2025 Jun 25]. https://www.epa.gov/power-sector/power-sector-data-crosswalk.
[71] US Environmental Protection Agency. 2025. Clean Air Markets Program Data (CAMPD). [accessed 2025 Jun 25]. https://campd.epa.gov.
[72] Livermore Lab Foundation. c2025. Roads to Removal – Options for carbon dioxide removal in the US. [accessed 2025 Jun 25]. https://roads2removal.org/.
[73] National Energy Technology Laboratory. 2022. NATCARB Atlas Saline Basin 10km Grid - EDX. [accessed 2025 Jun 25]. https://edx.netl.doe.gov/dataset/natcarb-atlas-saline-basin-10km-grid.
[74] US Environmental Protection Agency. c2025. Sole Source Aquifers. [accessed 2025 Jun 25]. https://epa.maps.arcgis.com/apps/webappviewer/index.html?id=9ebb047ba3ec41ada1877155fe31356b.
[75] https://www.jstor.org/stable/24747845
[76] Livermore Lab Foundation. c2025. Chapter 4 in Roads to Removal – Options for carbon dioxide removal in the US. [accessed 2025 Jun 25]. https://roads2removal.org/.

We sourced pipeline cost data from five different studies and calculated the inflation index to present day using piping indices.[77, 78, 79, 80, 81, 82] Convergence of the studies was high with low standard deviation. We also assumed permitting and development costs.

We verified routing manually for the few sites which relied on long distance pipelines (> 40km). We considered all other locations as connecting to existing pipelines or to areas with existing Class VI well permits, substantial Class II wells, or onsite low-cost saline aquifers. These locations would have to be further investigated to determine exact the well site and we gave them cost contingency increases based on the existing characterization of the relevant reservoir (depth, aquifer proximity, porosity etc.).

[77] Heddle G, Herzog H, Klett M. 2023. The Economics of $CO_2$ Storage. Massachusetts Institute of Technology Laboratory for Energy and the Environment, MIT LFEE 2003-003 RP (2003): 115. [accessed 2025 Jun 25]. https://energy.mit.edu/wp-content/uploads/2003/08/MIT-LFEE-03-003-RP.pdf.
[78] Smith E, Morris J, Kheshgi H, Teletzke G, Herzog H, Paltzev S. 2021. The cost of $CO_2$ transport and storage in global integrated assessment modeling. 2021. International Journal of Greenhouse Gas Control. 109:103367. doi:10.1016/j.ijggc.2021.103367.
[79] Denbury. 2015. Carbon Capture from Oil Refining. [accessed 2025 Jun 25]. https://www.pnwer.org/uploads/2/3/2/9/23295822/schnake_[with_edits]_2015-06_co2_eor_(pacific_northwest_erc).pdf
[80] National Petroleum Council. 2019. Chapter Six in Meeting the Duel Challenge: A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage. [accessed 2025 June 26]. https://dualchallenge.npc.org/files/CCUS-Chap_6-030521.pdf.
[81] Intergovernmental Panel on Climate Change. 2005. Chapter 4 in Carbon Dioxide Capture and Storage (SRCCS). [accessed 2025 Jun 25]. https://archive.ipcc.ch/report/srccs/.
[82] FederalReserve Bank of St. Louis. 2025. Producer Price Index by Industry: Iron and Steel Pipe and Tube Manufacturing from Purchased Steel: Iron and Steel Pipes and Tubes, from Purchased Iron and Steel. [accessed 2025 Jun 25]. https://fred.stlouisfed.org/series/PCU3312103312100.

## Appendix C: Focus on deregulated markets

For purposes of this analysis, we focused primarily on deregulated power markets. Fully regulated markets present a more complex pathway to engagement with data centers. This is because power generating entities cannot negotiate directly with data centers in regulated markets.

### Background on power market structure in the US

The US power landscape is a divided series of grids that are composed of different generation and load makeups, transmission constraints, and regulatory structures. This requires vastly different power generation systems and contract structures to meet regional differences. It is critical to understand the specifics of regional power markets to identify opportunities for deploying CCUS technologies on natural gas-fired generation.

#### Power market regulatory structure

The regulatory structure of the US power markets (**figure 13**) can be divided into two general categories; regulated and deregulated (typically termed regional transmission entity (RTO) or independent system operator (ISO) regions).

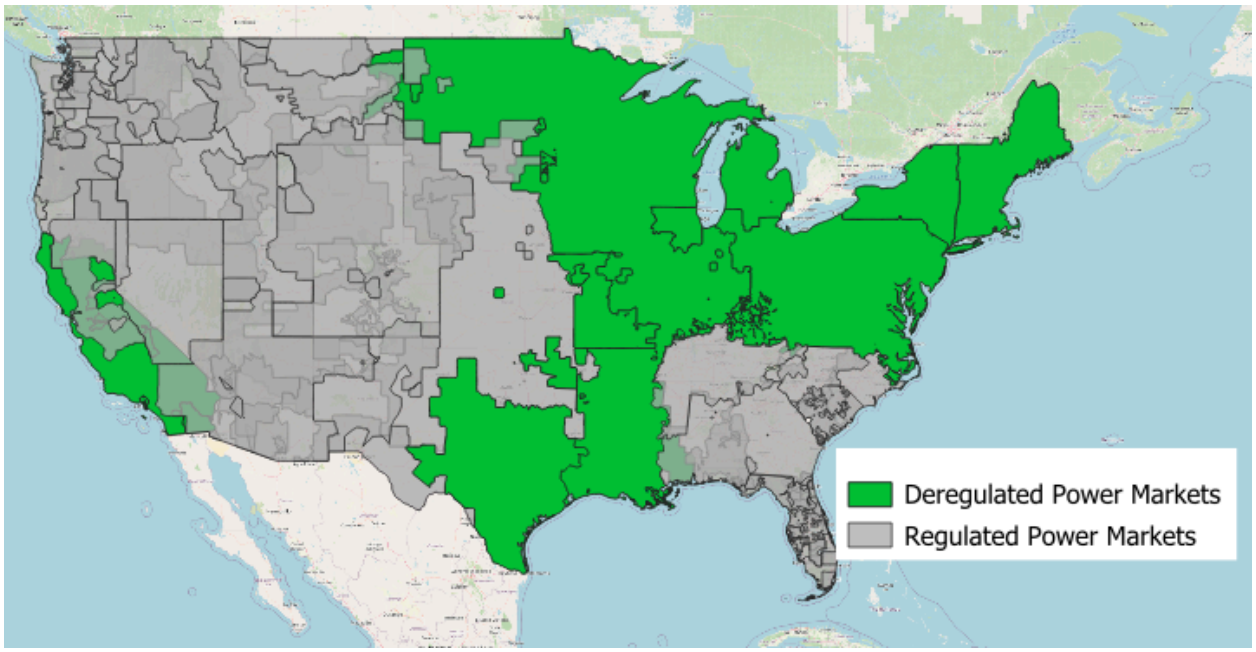



**Figure 13**: Regulated versus non-regulated power market regions of the US. Source: Carbon Direct.

Regulated markets are comprised of vertically integrated utilities—companies that own and control electricity generation, transmission, and distribution—where large loads apply for power service to the utility. The regulated utility and the public service commission  negotiate a tariff, which is the cost of service plus the rate of return the load pays to the utility for service. The tariff amount is governed by a process set out by the state and public utility commissions. Regulated power regions have restrictions on who can generate power in these regions. The regulated utility procures new power generation resources (from either the asset itself or from PPAs) through Request for Proposal processes. Individual consumers have historically had limited options to

influence or control this process, although this may be changing due to the creation of new tariffs for hyperscalers.[83]

Deregulated markets are regions where utilities have split ownership of power generation, transmission assets, and obligations to serve loads. A regional power grid is managed by an independent entity (an ISO or RTO), which is responsible for ensuring the reliability of the power grid. These regions have more flexibility as to who can own generation assets and how they are structured.

[83]Jenkins LM. 2025. The 'clean transition tariff' won approval in Nevada. What's next for Fervo? Latitude Media. [accessed 2025 Jun 25]. https://www.latitudemedia.com/news/the-clean-transition-tariff-won-approval-in-nevada-whats-next-for-fervo/.

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## Authors and contributors

Nicki Stuckert, PhD, Senior Decarbonization Engineer
Patti Smith, Electricity Decarbonization Lead
Daniel Garcia, Life Cycle Assessment Lead
Jordan Alford, Senior Industrial Decarbonization Engineer
Eva Guadamillas, Client Engagement Manager
Ehren Foss, Principal Product Architect
Liam Kilroy, Senior Research Associate
Rory Jacobson, Head of Policy
Thaddeus Woody, Policy Analyst
Sarah Braverman, Policy Analyst
Adrianna Sutton, Senior Science Writer and Editor
Molly Tucker, Science Writer and Editor

## Reviewers

Julio Friedmann, PhD, Chief Scientist
A.J. Simon, Director of Industrial Decarbonization
Colin McCormick, PhD, Principal Scientist
Betsey Rafeld, Senior Client Engagement Manager
Zara Ahmed, DrPH, Chief Operating Officer


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