Institute for Energy Economics
and Financial Analysis

Blue Hydrogen: Not Clean, Not Low Carbon, Not a Solution

Making Hydrogen from Natural Gas Makes No Sense

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Key Findings

The U.S. government significantly understates the likely impact of producing hydrogen from fossil fuels on global warming in at least four ways.

It assumes that just 1% of the methane being used to produce hydrogen will be emitted into the atmosphere between the well and the production facility. This is far less than recent peer-reviewed scientific analyses have found and that has been identified by airplane and satellite emission surveys.

It focuses solely on the 100-year Global Warming Potential (GWP) of methane, a very potent greenhouse gas. This significantly understates methane's environmental impact on global warming, since its 20-year GWP is more than 80 times that of carbon dioxide while its 100-year GWP is much lower.

Contrary to scientific evidence, it assumes that hydrogen does not have any impact on global warming when it leaks into the atmosphere.

It relies on the overly optimistic and unproven assumption that hydrogen production projects will be able to capture almost all of the carbon dioxide they create.

Executive Summary

Blue hydrogen hype has spread across the U.S., spurred by the billions of dollars of government funding and incentives included in the 2021 Bipartisan Infrastructure Law (BIL) and the 2022 Inflation Reduction Act (IRA). The fossil fuel industry promises that blue hydrogen, produced from methane or coal, can be manufactured cleanly and contribute to climate change mitigation measures. As we demonstrate in this report, the reality is that blue hydrogen is neither clean nor low-carbon. In addition, pursuing it will waste substantial time that is in short supply and money that could be more wisely spent on other, more effective investments for reducing greenhouse gas emissions in the immediate future.

In short, fossil fuel-based “blue” hydrogen is a bad idea.

Blue hydrogen’s environmental benefits rest largely on the assumptions baked into a Department of Energy (DOE) model named GREET (Greenhouse Gases, Regulated Emissions and Energy use in Transportation) that is the congressionally mandated evaluation tool for U.S. hydrogen projects. Due to a set of unrealistic and flawed assumptions, the model significantly understates the likely greenhouse gas intensity associated with blue hydrogen production.

Among the key shortcomings:

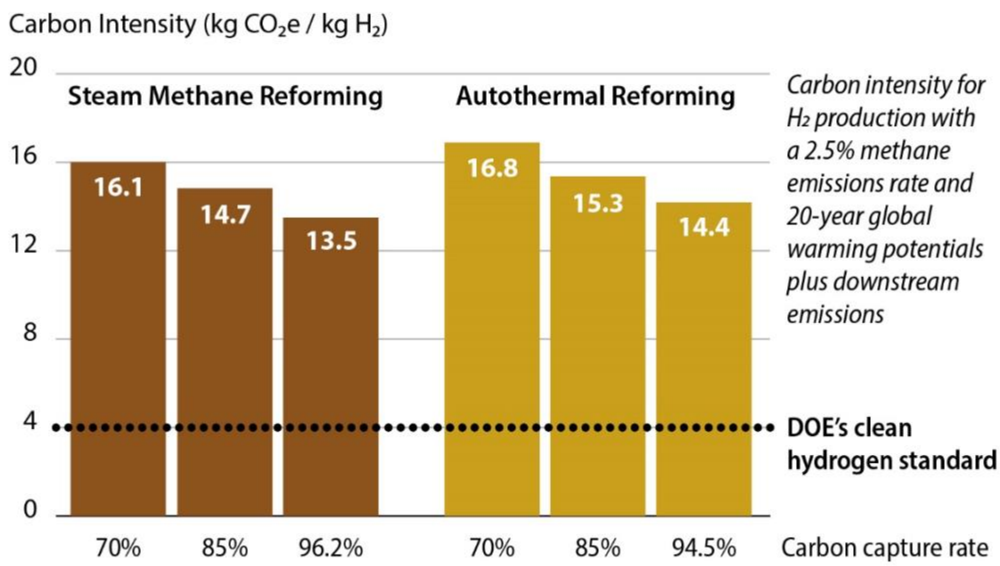
- It assumes an upstream methane emission rate of just 1%. This is far less than recent peer-reviewed scientific analyses have found and what has been demonstrated by numerous airplane and satellite surveys.
- It uses a 100-year Global Warming Potential (GWP). This significantly understates methane’s environmental impact in the short term, since its 20-year GWP is more than 80 times that of carbon dioxide (CO_2).
- It does not include any estimate (either over 20 or 100 years) for the global warming impact of hydrogen, which works to extend the lifetime of methane and increase its atmospheric abundance. Hydrogen also has a 20-year GWP more than 30 times that of CO_2.
- It does not include a full life cycle analysis (LCA) of all the emissions from the blue hydrogen production process. In particular, downstream emissions from the produced hydrogen and the generation of the electricity needed to compress, store and transport the hydrogen to the ultimate user(s) are excluded.
- It includes overly optimistic assumptions about the effectiveness of carbon capture processes.

Using more realistic numbers shows blue hydrogen to be a dirty alternative. For example, if we change just two variables—using methane’s 20-year GWP and a more realistic 2.5% methane emission rate—the carbon intensity of blue hydrogen calculated by GREET jumps to between 10.5 and 11.4 kilograms of CO_2e/kgH_2 (kilograms of carbon dioxide equivalents emitted per kilogram of hydrogen). This is between two and three times the 4.0 kg CO_2e/kg hydrogen Clean Hydrogen

Production Standard (CHPS) established by Congress and the DOE. Note that these already very high carbon intensity figures still reflect DOE's overly optimistic assumption that hydrogen production facilities will capture at least 94.5% of the CO_2 they produce. They also exclude the impact of downstream hydrogen emissions.

If more conservative assumptions are used, reflecting: 1) more realistic carbon capture rates; 2) downstream leakage of the hydrogen produced; and 3) downstream CO_2e emissions from the production of the electricity needed to fully compress, store and transport the hydrogen to the site where it will be used, then blue hydrogen gets even dirtier, with a carbon intensity more than three times as much as the DOE's clean hydrogen standard.

Figure ES 1: The Carbon Intensity of Blue Hydrogen Using 20-Year GWPs and More Reasonable Ranges of Assumptions for Methane Emissions and Hydrogen Leakage, Related Downstream Emissions and Carbon Capture Rates



Source: DOE GREET model, IEEFA analysis.

Given these results, IEEFA is extremely concerned that the current blue hydrogen hype is going to result in the funding of projects that exacerbate climate change and lock in our reliance on fossil fuels for decades. For this reason, we have undertaken a series of analyses into the emissions from blue hydrogen production based on current scientific knowledge of methane emissions and hydrogen leakage rates and the existing status of carbon capture and sequestration (CCS) technologies. This report focuses on the production of blue hydrogen from methane; a subsequent report will examine hydrogen from coal gasification.

Background

A Note About Terminology

Hydrogen produced from natural gas with carbon capture is called blue hydrogen.[1] Proponents of blue hydrogen claim that the fuel is clean and low-carbon. This report will show that this claim is not true.

What Does the Federal Government Define as Clean Hydrogen?

The 2022 Inflation Reduction Act (IRA) defined qualified clean hydrogen as that which emits 4.0 kilograms or less of CO_2e for each kilogram of hydrogen produced (4.0 kg CO_2e/kg hydrogen). The DOE has recently adopted this same $\leq$4.0 kg CO_2e/kg hydrogen standard for emissions based on what is called a well-to-gate analysis that excludes all emissions downstream of the production facility, except for those associated with the transportation and sequestration of the captured CO_2.[2]

Hydrogen Production Technologies

There are two main hydrogen production technologies that use natural gas as feedstock to produce hydrogen.

Steam methane reforming (SMR) is the main technology now being used to produce hydrogen from methane. An SMR mixes natural gas, air and high-temperature steam to produce hydrogen and CO_2 through a two-step chemical process. In a third step in the SMR process, CO_2 and other impurities are removed, essentially leaving pure hydrogen. Only three of the commercial plants in the world currently using SMR technology to produce hydrogen are capturing any of the CO_2 they create. In addition to being used as a feedstock for the methane needed in an SMR, natural gas also is burned to produce the external energy needed to drive the steam reforming process.

Autothermal reforming (ATR) is a process in which natural gas, pure oxygen and steam are mixed to produce hydrogen. Adding oxygen into the process produces the energy required for the conversion of methane so external burning of natural gas is not required. As in an SMR, the syngas is converted into hydrogen and CO_2. ATR is expected to be more commonly used in the future to produce hydrogen from natural gas. There aren't any commercial-scale ATR hydrogen plants in the world that capture the CO_2 they create.

[1] The main constituent of natural gas is methane, an extremely potent greenhouse gas. Methane has an impact on global warming that is 83 times that of CO_2 during the first decades after it is emitted and 30 times that of CO_2 after 100 years.
[2] U.S. Department of Energy. Clean Hydrogen Production Standard (CHPS) Guidance. June 2023.

Methodology

For this analysis, following the congressional mandate in the IRA, we have used the DOE's Greenhouse Gases, Regulated Emissions, and Energy use in Transportation (GREET) model (GREET1_2022 rev.1, released March 2023).[3] The model comes pre-populated with data, which allows users to select a hydrogen production pathway and generate estimates of well-to-gate emissions. We modeled more than 100 scenarios, adjusting selected parameters in the model to examine the conditions where a facility producing blue hydrogen from natural gas would meet the federal standard for clean hydrogen of CO_2e emissions of 4.0 kg CO_2e/kg hydrogen or less.

Unfortunately, the current version of the GREET model does not reflect either hydrogen's global warming potential (GWP) or any other CO_2e emissions associated with activities downstream from the production facility, other than those having to do with management of the captured CO_2. To overcome this limitation, we have created Excel-based estimates for the carbon intensity of these downstream emissions that we have combined with GREET's carbon intensity outputs in some of our scenarios.

What This Report Does Not Include

First, this report focuses exclusively on the production of blue hydrogen from natural gas. The carbon intensity of blue hydrogen produced from coal or renewable natural gas will be examined in subsequent reports in the near future.

Second, this report does not examine the reasonableness of the tremendous growth in the demand for hydrogen projected by proponents of transitioning to much greater use of the fuel. That also will be a subject of a future IEEFA report.

Third, this is not an economic analysis. It solely focuses on the critical question of whether blue hydrogen will be clean and low-carbon, not on its cost relative to other approaches to reducing greenhouse gas emissions.

Finally, the IRA allows the use of the DOE GREET model or an alternative. Given the urgency to complete this analysis before the DOE decides how to distribute billions of dollars to proposed hydrogen hubs (which almost surely will include some, if not many, blue hydrogen projects), we have used the GREET in our analysis.

[3] Argonne National Laboratory. GREET Excel Model Platform. March 28, 2023.

DOE's GREET Model Understates the Carbon Intensity of Producing Blue Hydrogen

The GREET model includes four unrealistic and extremely favorable assumptions that result in a significant reduction of the likely carbon intensity of blue hydrogen, making it appear cleaner and lower-carbon. These assumptions also cause the model 1) to downplay the climate risks associated with blue hydrogen and 2) minimize the gamble that the federal government is making by supporting the rapid development of hydrogen produced from fossil fuels.

These include:

1. Focusing exclusively on 100-year GWPs while ignoring methane's very potent 20-year GWP.
2. Assuming that only 1% of methane is emitted upstream of the hydrogen production facility,[4] even though recent scientific surveys and analyses have found much higher emission rates in major U.S. oil and gas-producing basins.
3. Assuming that blue hydrogen production facilities will capture almost all of the CO_2 they produce—even though there is no evidence that any commercial-scale carbon capture facility in the world has done so.
4. Entirely ignoring the global warming effects of hydrogen.

Even with these optimistic assumptions, the GREET model shows that producing blue hydrogen with ATR technology does not meet the DOE's clean hydrogen standard, posting a model-calculated carbon intensity of 4.4 kg CO_2e/kg hydrogen produced, which is more than the 4.0 kg CO_2e/kg hydrogen DOE standard. GREET shows a calculated carbon intensity of 3.4 kg CO_2e/kg hydrogen for producing blue hydrogen with SMR technology, which is less than the federal standard but with little margin for less-than-ideal production performance.

Unfortunately, the DOE has indicated it still will support projects that do not meet the 4.0 CHPS as long as they "demonstrably aid the achievement" of the CHPS by mitigating emissions "as much as possible across the supply chain." Such broad language will open the door to the funding of dirtier—perhaps much dirtier—blue hydrogen projects. Moreover, there doesn't seem to be much of a point in establishing a Clean Hydrogen Production Standard if the standard is going to be immediately violated by the funding of projects with higher carbon intensities.

In addition, the GREET model does not effectively represent the emissions that might occur during the compression, transport and permanent sequestration of the captured CO_2. The risks associated with CO_2 management have not been sufficiently modeled in GREET to understand the true carbon

[4] Upstream methane emissions include the losses at the well sites, plus those incurred during the processing, storage and transport of gas in high-pressure pipelines.

intensity of this critical component of hydrogen production. But our results show that the carbon intensity of producing blue hydrogen from natural gas is far more than the federal government's standard for clean hydrogen and would be even greater if we did reflect those risks.

Finally, the DOE GREET model also includes a steam credit for SMR plants that significantly reduces the calculated carbon intensity of plants using that technology. The credit is based on the assumption that the owner of a blue hydrogen production facility will be able to sell its unused steam to a neighboring industrial facility as a replacement for steam that otherwise would have been produced in a natural gas boiler, avoiding some level of CO_2 emissions.

Although this is an appealing idea, it is unclear how many proposed SMR hydrogen production facilities actually will have industrial neighbors located close enough to use excess steam; neighbors that are interested in entering into such an arrangement; or how much excess steam would be exported. Therefore, we have excluded the steam credit from our analysis.

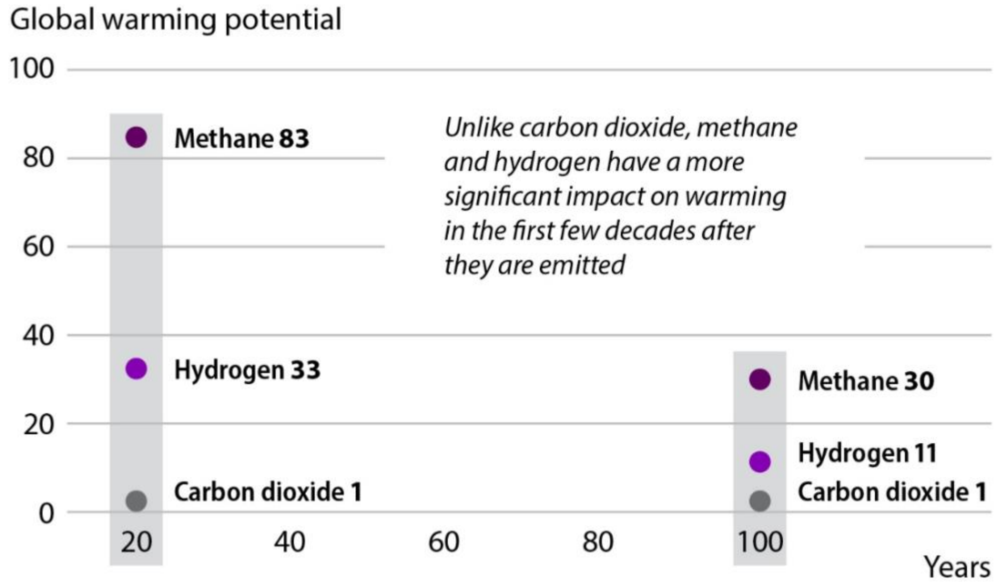
Not Considering 20-year GWPs Means the Effects of Methane Emissions and Hydrogen Leakage Are Underestimated

Methane is a very potent greenhouse gas. Measured over 20 years, its GWP is approximately 83 times higher than CO_2; over 100 years, its GWP is approximately 30 times higher.[5] Hydrogen also is a potent yet indirect and short-lived global warming gas since it extends the amount of time that methane remains in the atmosphere and its concentration. Recent scientific analyses have shown that hydrogen's 20-year GWP is approximately 33 times that of CO_2 and its 100-year GWP is 11 times higher, about double the amount previously thought.[6] Although both methane and hydrogen are widely recognized as potent yet short-lived global warming gases, the calculations of carbon intensity in the GREET model ignore methane's 20-year GWP, instead focusing exclusively on its still significant but far lower 100-year GWP. The model does not include any GWP for hydrogen.

The timeline used in GREET for assumed methane and hydrogen GWP is important because the GWP for each gas declines over time, as shown in Figure 1 below.

[5] IPCC Sixth Assessment Report (AR6). 2021-23.
[6] Warwick, et al. Atmospheric implications of increased hydrogen use. April 2022.

Figure 1: Global Warming Potential (GWP) Values Over Time for Methane and Hydrogen



Sources: IPCC AR6, Warwick et al. (2022)

The use of 100-year GWPs may have made sense decades ago to focus on how climate change was going to be a problem that would affect the world over the long term and, therefore, that 100-year GWPs of greenhouse gases were the most relevant. But that no longer holds true. The climate crisis that many have feared is already here and has already had "widespread and rapid" adverse impacts on the world and its climate, as the extreme heat and weather experienced on all seven continents this summer have confirmed. The most recent report of the Intergovernmental Panel on Climate Change (IPCC) has observed:

> *Widespread and rapid changes in the atmosphere, ocean cryosphere and biosphere have occurred. Human-caused climate change is already affecting many weather and climate extremes in every region across the globe. This has led to widespread adverse impacts and related losses and damages to nature and people. Vulnerable communities who have historically contributed the least to current climate change are disproportionately affected.*[7]

For this reason, many climate scientists now emphasize that a "focus on the next few years is exceptionally important,"[8] and that it's "now or never, if we want to limit global warming to 1.5 [degrees centigrade or] 2.7 [degrees Fahrenheit]."[9] Focusing solely on 100-year GWPs, as the DOE GREET model does, is misguided and minimizes the effects of critical shorter-lived gases like methane and hydrogen.

[7] Intergovernmental Panel on Climate Change. Synthesis Report of the IPCC Sixth Assessment Report (AR6), Summary for Policymakers. March 2023, p. 5.
[8] Warwick, *op. cit.*
[9] IPCC Press Release. The evidence is clear: the time for action is now. We can halve emissions by 2030. April 4, 2022.

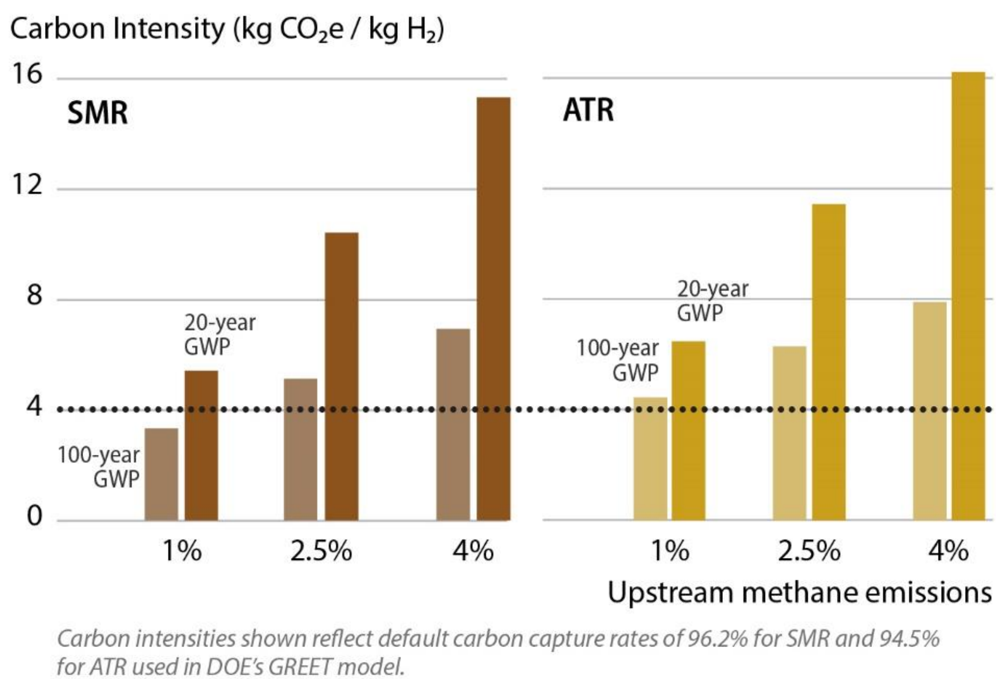
And it is not as if there will only be upstream emissions of methane into the atmosphere the first or second year that a blue hydrogen production facility will be operating. There will be continuous streams of both "upstream" methane and "downstream" hydrogen being leaked from the blue hydrogen value chain every day that a production facility is operating, every year, until all leaks are found and prevented. The concentrations of the methane and hydrogen in the atmosphere can reasonably be expected to remain high in the future—even decades down the line.

Clearly, one of the very best practices for avoiding taking actions that might make climate change worse is to consider both 20-year and 100-year GWP timeframes when determining how clean and low-carbon blue hydrogen projects really are and when to provide incentives for their construction and operation.

A 1% Methane Emission Rate Is Not Consistent With Recent Scientific Surveys and Analyses

The methane emission rate is a key assumption in the GREET model's calculation of blue hydrogen carbon intensities. Figure 2 shows how much higher the carbon intensity of blue hydrogen becomes when the assumed methane emission rate goes up, particularly when the impact is considered over a 20-year GWP time horizon.

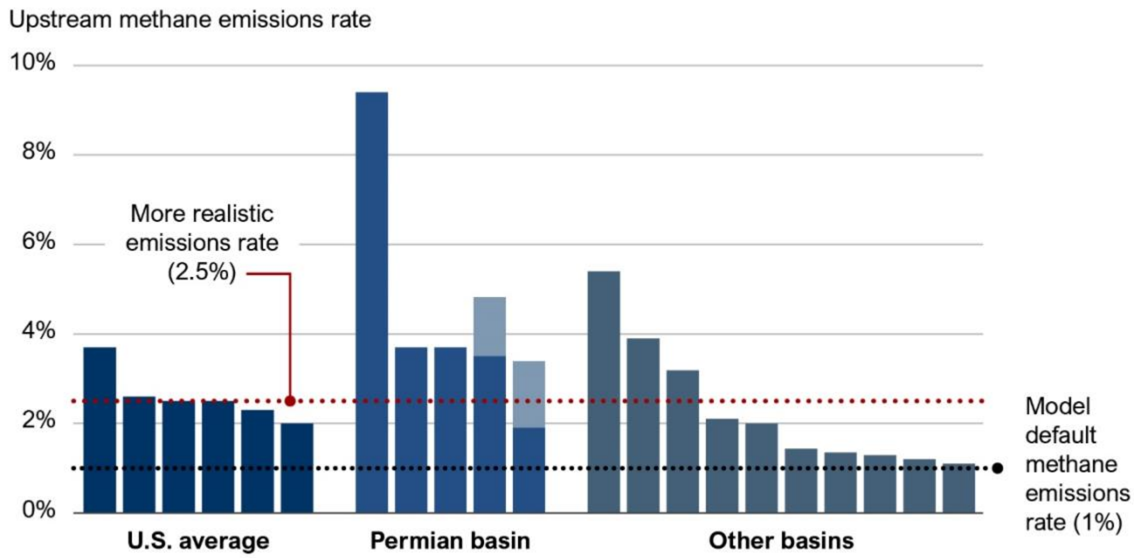
Figure 2: The Impact of Methane Emission Rates on Blue Hydrogen's Carbon Intensity



Source: IEEFA analysis of the results of GREET model runs.

The GREET model assumes a methane emission rate of just 1%.[10] A literature review shows that this default 1% is significantly lower than the methane emission rates that have been found by recent airplane and satellite surveys, and calculated in peer-reviewed scientific analyses of U.S. oil and natural gas-producing basins, as can be seen in Figure 3 and Table 1 below.

Figure 3: Recent Scientific Analyses and Surveys of Methane Emissions



Sources are listed in Table 1 on the following page.

[10] DOE Office of Scientific and Technical Information. Hydrogen Life-Cycle Analysis in Support of Clean Hydrogen Production. October 2022.

Table 1: Upstream Methane Emission Rate Studies

Study	Year Published	Region	Leak Rate
Alvarez et al.[11]	2018	U.S.	2.3%
Peischl et al.[12]	2018	Bakken Shale, ND	5.4%
		Barnett Shale, TX	1.5%
		Denver Basin, CO	2.1%
		Eastern Eagle Ford Shale, TX	3.2%
		Western Eagle Ford Shale, TX	2.0%
Ren et al.[13]	2019	Marcellus Shale	1.1%
Schneising et al.[14]	2020	Permian Basin	3.7%
		Bakken Shale, ND	1.3%
		Eagle Ford Basin, TX	1.4%
		Anadarko Basin, OK	3.9%
		Appalachia	1.2%
Zhang et al.[15]	2020	Permian Basin	3.7%
Lyon, et al.[16]	2020	Permian Basin	1.9%-3.3%
		U.S.	2.5%
Chen et al.[17]	2022	Permian Basin	9.4%
Shen et al.[18]	2022	U.S.	2.0%
		Permian Basin	3.5%-4.6%
Howarth[19]	2022	U.S.	2.6%
Lu et al.[20]	2023	U.S. (in 2010)	3.7%
		U.S. (in 2019)	2.5%

Other recent aerial surveys have also found significantly higher methane emissions in major basins of natural gas production in the U.S. than had previously been included in the U.S. Environmental Protection Agency's (EPA) Greenhouse Gas Inventory.

[11] *Science*. Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain. 2018.
[12] *Journal of Geophysical Research: Atmospheres*. Quantifying Methane and Ethane Emissions to the Atmosphere from Central and Western U.S. Oil and Natural Gas Production Regions. 2018.
[13] *Journal of Geophysical Research: Atmospheres*. Methane Emissions from the Marcellus Shale in Southwestern Pennsylvania and Northern West Virginia based on Airborne Measurements. 2019.
[14] *Atmospheric Chemistry and Physics*. Remote sensing of methane leakage from natural gas and petroleum systems revisited. 2020.
[15] *Science*. Quantifying methane emissions from the largest oil-producing basin in the United States from space. 2020.
[16] *Atmospheric Chemistry and Physics*. Concurrent variation in oil and gas methane emissions and oil price during the COVID-19 pandemic. 2021.
[17] *Environmental Science & Technology*. Quantifying regional methane emissions in the New Mexico Permian Basin with a comprehensive aerial survey. 2022.
[18] *Atmospheric Chemistry and Physics*. Satellite quantification of oil and natural gas methane emissions in the U.S. and Canada including contributions from individual basins. 2022.
[19] Robert Howarth. Methane Emissions from the Production and Use of Natural Gas. December 2022.
[20] *Proceedings of the National Academy of Sciences of the United States of America*. Observation-derived 2010-2019 trends in methane emissions and intensities from US oil and gas fields tied to activity metrics. 2023.

- Methane emissions from natural gas gathering lines in the Permian Basin are at least 14 times higher than EPA estimates.[21] Gathering lines transport unprocessed gas from well sites to storage and processing facilities.
- Measurements from the Permian Basin, and the Bakken and Eagle Ford basins indicate that flaring is significantly less effective at reducing methane emissions—flaring is only 91.1% effective, vs. the previously estimated 98% efficiency.[22]
- The carbon intensity of oil and gas production in the Gulf of Mexico is double previous estimates. This is driven by updated methane emissions that are three and 13 times what had been previously estimated in federal and state water inventories, respectively.[23]

Robert W. Howarth, a Cornell University research scientist, has analyzed the results of all peer-reviewed estimates of methane emissions in gas fields in the U.S. prepared through the middle of 2022. Based on this analysis, which omitted the two highest satellite-based estimates as possible outliers, Howarth found that the median upstream methane emission rate is 3.7% of gas production. The mean emission rate, weighted by the volume of production in the different gas fields studied, is 2.6%.[24] Howarth's results are much more consistent with the results of the recent scientific surveys and analyses shown in Table 1 than the default 1% rate assumed in the DOE's model.

Based on the results of the analyses shown in Table 1 and Howarth's analysis, we have looked at a range of assumed methane emission rates of 1% to 4%, with a midpoint of 2.5%, in this analysis.

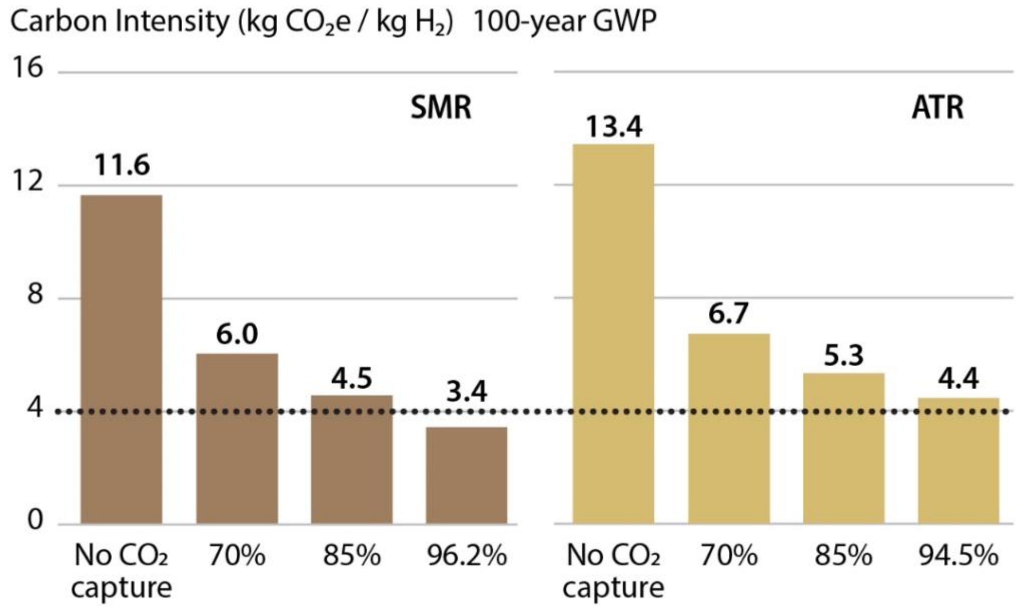
Carbon Capture Cannot Save Blue Hydrogen

Producing blue hydrogen without capturing any CO_2 is very dirty. Exactly how dirty depends on 1) the assumed methane emission and hydrogen leakage rates; 2) whether the carbon intensity of the blue hydrogen reflects methane's 20-year GWP or its significantly lower 100-year GWP; and 3) what downstream emissions are included.

But even with the extremely favorable assumptions in DOE's GREET model, capturing almost all of the CO_2 created during the production process is essential if blue hydrogen's carbon intensity is going to be less than (or in the case of ATR plants, close to) the federal clean hydrogen standard.

[21] *Environmental Science & Technology Letters*. Methane Emissions from Natural Gas Gathering Pipelines in the Permian Basin. 2022.
[22] *Science*. Inefficient and unlit gas flares both emit large quantities of methane. 2022.
[23] *Proceedings of the National Academy of Sciences*. Excess methane emissions from shallow water platforms elevate the carbon intensity of US Gulf of Mexico oil and gas production. 2023.
[24] Robert Howarth. Methane Emissions from the Production and Use of Natural Gas. December 2022.

Figure 4: Carbon Intensity of Hydrogen Production With and Without Carbon Capture



Source: IEEFA runs with DOE's GREET model.

This figure shows both that producing hydrogen without carbon capture is very dirty and that capturing almost all of the CO_2 at the production facility is essential even under the favorable assumptions in the DOE model's best case. Capturing 70% or even 85% of the CO_2 is not enough to make blue hydrogen clean under the federal standard, even though capturing either amount would be a significant step up from the technology's current performance at commercial-scale projects.

Just Adding Carbon Capture Cannot Make Blue Hydrogen Clean or Low Carbon

Developers and promoters of carbon capture, including the DOE, act as if the technology has already been proven of being capable of capturing almost all of the CO_2 produced by a commercial-sized hydrogen production facility or power plant and will do so for decades.[25] The reality is far from these overly optimistic assumptions.

First, there is no evidence from the historical performance of commercial-scale projects that carbon capture projects actually have been able to achieve such high capture rates on a sustained basis over the long term.

[25] For example, the default assumptions in both the GREET model and the Comparison of Commercial State-of-the-Art, Fossil-Based Hydrogen Production Technologies prepared by the DOE's National Energy Technology Laboratory (NETL) is that an SMR will have a 96.2% capture rate, and an ATR will capture 94.5% of the CO_2 it creates. However, as revealed in the NETL study, this assumption is based mainly on the high capture rates being claimed for proposed hydrogen production projects even though none of these projects have yet been built and operated or are even under construction at this time. Some of these projects haven't even been funded yet.

Second, the testing of new and enhanced carbon capture technologies that is currently under way is only small-scale, with even the large pilot projects currently being touted by the DOE only planning to capture 5% or less of the CO_2 produced daily by two coal-fired power plants in Illinois and Wyoming.

Third, even when almost all of the CO_2 created at a production facility is assumed to be captured, blue hydrogen remains very dirty when a more realistic upstream methane emission rate and the gas's 20-year GWP are considered in the DOE GREET model. This is true whether or not estimates for downstream emissions attributable to the hydrogen created at the production facility are included.

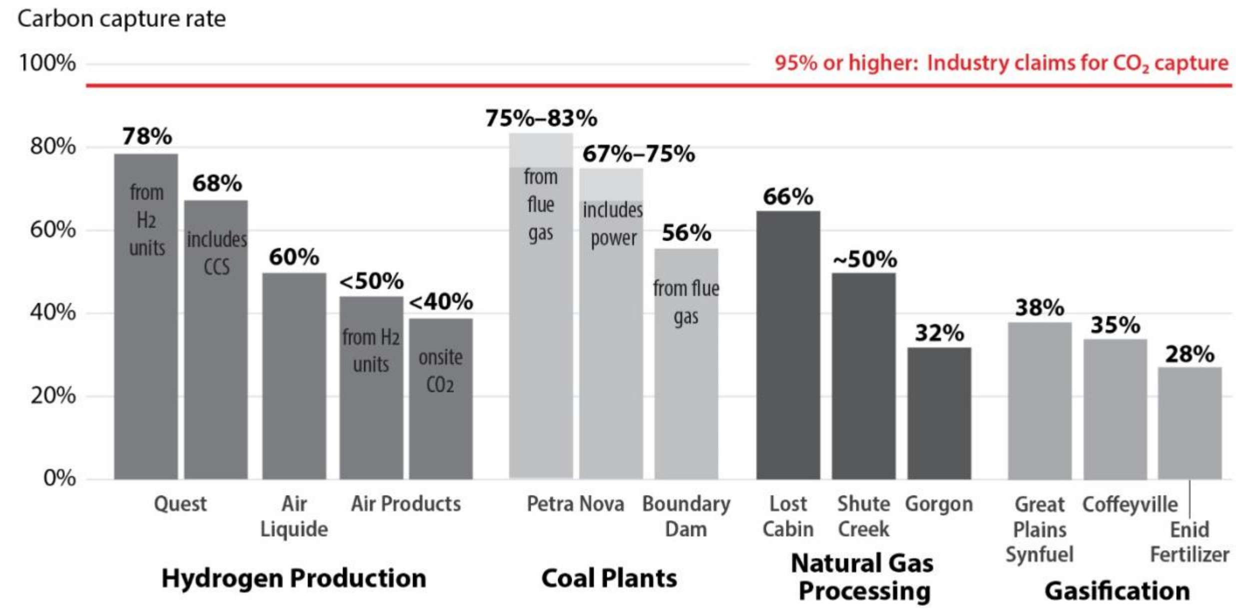
There Is No Evidence That Existing Commercial-scale Carbon Capture Projects Have Captured Anywhere Close to 95% of the CO_2 They Create

Contrary to what promoters of CCS generally suggest, carbon capture already has had numerous failures and project cancellations—some very expensive—and there is no evidence that any of the between 27 and 30 existing CCS projects have captured even 85% of the CO_2 they create.[26]

Unfortunately, most of the existing carbon capture facilities do not publish either their actual CO_2 capture rates or the underlying data that would enable anyone to determine their actual capture rates. Nevertheless, IEEFA has been able to identify the CO_2 capture rates for the following projects.

[26] Government Accountability Office. Carbon Capture and Storage: Actions Needed to Improve DOE Management of Demonstration Projects. December 2021. Also see: Gizmodo. The Energy Department Blew $1.1 Billion on Carbon Capture Projects that Were Mostly Failures. January 11, 2022. Also see: *Energy Policy*. What went wrong? Learning from three decades of carbon capture utilization and sequestration (CCUS) pilot and demonstration projects. 2021.

Figure 5: CO_2 Real-world Capture Rates at Commercial-scale Hydrogen Production, Coal-fired Power Plants, Natural Gas Processing and Gasification Facilities



Sources: IEEFA analyses based on publicly available data.

Most importantly:

- There are only three commercial-scale hydrogen production facilities in the world currently operating with CO_2 capture. All use SMR technology to produce hydrogen.
- None of these facilities has captured even 80% of the CO_2 they produce—and only one, Project Quest in Alberta, has captured 68% of its CO_2. And it only appears to have achieved that level of performance if the emissions associated with the capture process are ignored.
- No CO_2 has been captured at any commercial-scale facility using ATR technology.

Even where there is not enough data to determine capture rates, it is clear that some other projects have seriously underperformed the amounts of CO_2 developers initially claimed would be captured. For example, the Illinois Industrial Carbon Capture and Storage Project underperformed from a forecast 22% capture rate to an actual 12% capture rate, a drop of almost half.[27]

It is possible future CO_2 capture rates will be greater than the levels achieved at existing facilities. ATR technology is expected to produce a more concentrated stream of CO_2 that will facilitate capture. Higher Section 45V hydrogen production credits and Section 45Q carbon capture subsidies in the IRA are likely to encourage project developers to invest more to improve capture rates. And lessons learned from the currently operating capture projects, as well as numerous failures, may lead

[27] IEEFA. The Carbon Capture Crux: Lessons Learned. September 2022.

to improved capture rates. However, it still remains a big gamble how close future capture rates will be to the near-perfect performance assumed in GREET.

We also have been told that the reason for the low capture rates at existing SMR plants is that they only capture CO_2 from one of the two streams of CO_2 produced during the hydrogen production process and that the future SMR projects will capture the CO_2 from both streams. That sounds reasonable. However, existing SMR plants that currently have carbon capture are already capturing the CO_2 from the more concentrated (and more easily captured) of these two streams.

However, it is still uncertain how successful an SMR will be at capturing the CO_2 from the less concentrated and more difficult to capture stream of CO_2 from the plant's flue gases. Unfortunately, there is no commercial-scale experience capturing similar less-concentrated streams of CO_2 from the flue gases of gas-fired power plants, and large-scale testing has not yet been undertaken. The project that has been hailed as a possible "game changer for gas-fired plants" is designed to capture only about 10 to 11 tons a day (1%) of the CO_2 from the 580-megawatt (MWe) Los Madenos natural gas-fired combined cycle plant in California.[28]

For this reason, although some factors might suggest that future CO_2 capture rates could be higher, there's no guarantee that future hydrogen production facilities will be able to capture almost all of the CO_2 they create. But that's precisely what DOE does with the default assumptions on carbon capture in the GREET model.

[28] The Mercury News. First-of-its-kind East Bay pilot project to capture harmful emissions, could be game-changer for gas-powered plants. July 15, 2023.

Debunking the Claim of 92.4% Carbon Capture at Petra Nova

Proponents have claimed that 90% CO_2 capture was achieved at the Petra Nova project, which captured CO_2 from 40% of the flue gases from the W.A. Parish plant Unit 8 in Texas. Although proponents of CCS have claimed that Petra Nova, which captured CO_2 from Unit 8 between January 2017 and April 2020, was a success, the reality is very different.

First, although NRG Energy's report to the DOE claimed that Petra Nova had captured 92.4% of the CO_2 that had been processed from Parish Unit 8 when the capture facility was operating at 100%, it did not provide the data needed to verify that claim. In fact, NRG did not say how much of the time the capture facility actually operated at 100%; its capture rate when it was not operating at 100%; or its average capture rate during the entire 40-month period that it operated.

In addition, as IEEFA has previously explained, the claim of 92.4% capture was not consistent with the annual generation and CO_2 emission data that NRG filed for the years 2017-20 with the DOE and the Environmental Protection Agency. Based on the data in NRG's filings for these years, it appears that the project's average CO_2 capture rate was more on the order of 75% to 83%, rather than 92.4%.[1]

Finally, both the proponents' claimed 92.4% and our calculated 75% to 83% capture rate actually overstate Petra Nova's performance because neither included the CO_2 emissions from the dedicated gas-fired combustion turbine that produced the electricity used to run the carbon capture facility. The total capture rate for the project was about 8% to 10% less when these emissions are included.

Petra Nova has been mothballed since 2020, although its current owner says it intends to restart the project later this year.[2] But it will be years before it is known how well Petra Nova will capture CO_2 in its second chance at life.

1. IEEFA. Petra Nova Mothballing Post-Mortem: Closure of Texas carbon capture plant is a warning. 2020. Also see: IEEFA. The Carbon Capture Crux: Lessons Learned. 2022.
2. Bloomberg. The World's Largest Carbon Capture Plant Gets a Second Chance in Texas. February 8, 2023.

IEEFA is not alone in concluding that carbon capture has not proven reliable enough at commercial scale to show that capture rates of 95% or higher can consistently be achieved in power, industrial or hydrogen production facilities.[29] For example, in comments to the EPA on the proposed Greenhouse Gas Regulations for Fossil-Fuel-fired Power Plants, Southern Company noted the following:

> *CO_2 capture on a small scale has been happening for many years in the petroleum, ethanol, and industrial chemical industries. While deployed in these industrial sectors for commercial uses, the technology has not been deployed to date at commercial-scale as an environmental control technology, where reliability and consistent performance are paramount requirements to ensure compliance with regulatory standards and permit conditions…*
>
> *Technical testing at the NCCC [National Carbon Capture Center] and the Technology Centre Mongstad (TCM) (located in Mongstad, Norway) has been valuable to evaluate carbon capture technologies and move them through the development curve to prepare them for demonstration. Several technologies that have been tested at these facilities are now in the FEED [Front End Engineering Design] state, which will refine the expected costs of those options. A technology needs to be demonstrated at a scale above the NCCC or TCM, however, to identify and address operational issues before being considered commercially available ...*[30]

A review of testing results for new carbon capture technologies reveals both the limited scale of this testing and the magnitude of the upscaling that will be required to make capture technologies successful and reliable at much larger commercial-size plants.

For example:

- Testing at the National Carbon Capture Center is designed to capture only small amounts (that is, the daily equivalent of tens of tons) of CO_2.[31]
- The Technology Centre Mongstad in Norway has the capability of capturing about 300 tons of CO_2 a day (210,000 tons per year) from an adjoining refinery and gas-fired power plant.[32]
- Two projects that are touted as "large pilot" carbon capture tests are designed to capture only ~170 tons per day (about 2.5%) of the CO_2 produced at the 405 MWe Dry Fork Station

[29] For example, see the following comments submitted to the EPA in its Pre-Proposal Docket on Greenhouse Gas Regulations: Comments of Southern Company. Comments of the Power Generators Air Coalition. Comments of Edison Electric Institute. Comments of the National Mining Association.

[30] EPA. Comments of Southern Company to EPA's Pre-Proposal Docket on Greenhouse Gas Regulations for Fossil Fuel-fired Power Plants. December 21, 2022.

[31] BASF. BASF and Linde successfully complete pilot project at National Carbon Capture Center in Wilsonville, Alabama. July 19, 2016. Also see: BASF. Carbon capture, storage and utilization: Linde & BASF team up to innovate carbon capture. Accessed on Aug. 21, 2023.

[32] Bloomberg. Mitsubishi Heavy Industries Engineering Successfully Completes Testing of New "KS-21" Solvent for Carbon Capture. Oct. 19, 2021.

coal plant in Wyoming and only ~220 tons per day (roughly 5%) of the CO2 produced by the Dallman 4 coal plant in Illinois.[33,34]

By way of comparison, existing and proposed blue hydrogen production facilities capture much larger amounts of CO_2 a year. For example:

- Air Products has said its existing blue hydrogen production facility in Texas captured a daily average of about 2,800 tons of CO_2 (1 million tons a year, on average) between 2013 and 2021 and is claiming that its proposed blue hydrogen production facility in Louisiana will capture more than 16,000 tons of CO_2 a day (5 million tons per year).[35]
- The data in Shell's annual reports to the province of Alberta claim that its Project Quest has captured a daily average of more than 4,300 tons of CO_2.[36]

Our point is not that small-scale testing of new technologies is wrong. It's wrong when proponents claim the results of small-scale tests demonstrate that new or enhanced carbon capture technologies will definitely capture almost all of the CO_2 and will reliably do so for decades, as assumed in the default GREET model inputs.

As the industry and the DOE should have learned by now through painful experience, serious and expensive problems can occur when scaling up new technologies. Southern Company's Kemper Integrated Gasification Combined Cycle (IGCC) project is a prime example of where a new technology can look ready for commercial development when tested at small scale but fails to operate reliability when applied at commercial scale.

As initially proposed, Kemper was going to use a brand-new technology called TRIG™ for gasifying coal, with the ultimate goal of capturing 65% of the CO_2 from the plant. According to Southern, TRIG™ had been successfully tested at the National Carbon Capture Center.[37] However, when the TRIG™ technology was installed at the commercial-scale Kemper plant, significant and repeated problems occurred with the new technology that Southern could not resolve despite multiple years of trying. As a result, the plan to burn gasified coal was scrapped and Kemper (since renamed Plant Ratcliffe) now is the world's most expensive natural gas-burning combined cycle power plant. The plant does not use gasified coal, and none of the CO_2 it produces has been captured. This painful and expensive experience explains Southern's warning that new capture technologies need to be demonstrated at larger scale. Its warning should be heeded before the federal government commits to funding proposed large-scale blue hydrogen facilities.

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[33] Wyoming Governor's Office. Wyoming ITC to host large-scale carbon capture test project. April 30, 2021. Also see: County17.com. Integrated test center welcomes 2 carbon capture projects. May 3, 2023.
[34] National Energy Technology Laboratory. Large pilot carbon capture project supported by NETL breaks ground in Illinois. Jan. 24, 2023.
[35] Air Products. Hydrogen technology for low-carbon solutions. Accessed Aug. 21, 2023.
[36] Government of Alberta. Quest Carbon Capture and Storage project: annual report, 2021. July 2022.
[37] Southern Company. 2016 Carbon Disclosure Report, p. 4.

In conclusion, it is possible that one of the capture technologies now being proposed for new blue hydrogen production facilities may indeed capture more than 90% or 95% of the CO_2 they would otherwise emit. But this success cannot be taken for granted on the basis of either the actual operating experience of existing hydrogen production facilities or the results of small-scale testing of new or upgraded capture technologies. For this reason, we have examined the carbon intensity of blue hydrogen with a range of capture rates from the GREET default (94.5% for ATR and 96.2% for SMR) to 70%, with a midpoint of 85%.

Hydrogen Has a Substantial Although Indirect Impact on Global Warming

Hydrogen matters for the global climate because its emissions extend the life of methane in the atmosphere and increase its concentration. This occurs because "hydrogen gas easily reacts in the atmosphere with the same molecule primarily responsible for breaking down methane."[38] As a result, hydrogen emissions affect the process by which methane is removed.[39] Although hydrogen is not a greenhouse gas, changes in its abundance in the atmosphere will change the concentrations of important greenhouse gases.[40] Scientists have warned that this process can have "decades-long climate consequences."[41]

Unfortunately, the DOE has ignored the effects of downstream hydrogen emissions entirely in calculations of the carbon intensity of blue hydrogen. It does this by (1) not including any GWP for hydrogen in the GREET model; (2) only considering the long-term effects of methane, not its potentially serious short-and near-term effects on global warming; and (3) stopping the calculation of carbon intensity at the back gate of the hydrogen production facility—except for the estimated emissions related to management of the captured CO_2. This means that no downstream emissions are included in the calculation—neither hydrogen emissions nor any CO_2 or methane emissions from the production of the energy needed to fully compress, store and transport the hydrogen to the sites where it will be used. These are significant omissions that have important consequences for the accuracy of the DOE's calculated carbon intensity of blue hydrogen and the impact that the emissions from the entire blue hydrogen value chain will have on global warming.[42]

Due to its extremely small size, hydrogen is a "slippery" module that can be expected to leak into the atmosphere at every stage of the blue hydrogen value chain, from production to compression to pipeline transport through final use. But because there is currently no commercially available sensing technology that can detect the very small leaks through which hydrogen can escape into the atmosphere and affect the climate, it is unknown how much hydrogen is currently being emitted from

[38] Princeton University. Switching to hydrogen fuel could prolong the methane problem. March 13, 2023.
[39] *Nature*. Risk of the hydrogen economy for atmospheric methane. 2022.
[40] Warwick et al. Atmospheric implications of increased hydrogen use. April 2022.
[41] Princeton University, *op. cit.*
[42] The entire hydrogen value chain includes all of the upstream and downstream activities related to the production of blue hydrogen as well as those at the production facility.

existing production facilities and the downstream processes (compression, storage and transport) in the hydrogen production value chain.[43] Efforts to identify hydrogen leaks have so far focused on finding larger leaks that can pose safety risks.

Without any empirical data on actual leakage rates, scientific analyses of the climate impact of hydrogen emissions have frequently looked at a wide range in their studies, generally from 1% or less to about 10%.[44] It is far better to recognize that the amount of hydrogen being emitted into the atmosphere is unknown than to pretend that such emissions do not exist at all, as the DOE currently does in the GREET model.

This seems a reasonable approach, and for this reason, we have chosen to include a 5% hydrogen leakage rate—the approximate midpoint in the 1% to 10% leakage rate—in this analysis.

The actual emissions from any individual blue hydrogen production value chain will depend on a variety of factors, including the distance and configuration of the pathway from the production facility to the end-user, whether the hydrogen will be transported as a gas or a liquid, and whether the hydrogen will be stored for any period of time. These factors will affect how much electricity will be required to compress, store and transport the hydrogen and, consequently, determine the CO_2e emissions from the generation of this electricity.

As General Electric has explained:

> *Once produced, hydrogen will most likely have to be transported and/or stored. This can be done as a gas or a liquid. When stored as a gas, tanks are typically kept at pressures in excess of 5000 psi (34.5 MPa). Compressing hydrogen from 20 bar (~290 psi) to 350 bar (~5000 psi, ~35 MPa) requires at least 1.05 kWh/kg; compression energies of 1.7–6.4 kWh/kg (~2630–9900 BTU/lb) may be more representative of requirements for real systems with losses and other inefficiencies. For comparison, according to the US Energy Information Administration, the average US residential home uses ~29 kWh of electricity per day. Hydrogen gas can be condensed to the liquid phase, but this requires a temperature of -423.6 °F (-252.9 °C) which is ~36 °F (~20 °C) above absolute zero. The process of liquefying hydrogen is highly energy intensive, requiring ~10–13.3 kWh of energy per kg of liquid hydrogen, which is ~30% of the lower heating value per kg of hydrogen. Once liquefied, storage tanks are typically double-walled and heavily insulated to maintain cryogenic conditions.*[45]

[43] *Atmospheric Chemistry and Physics*. Climate consequences of hydrogen emissions. July 2022.
[44] *Communications, Earth & Environment*. A multi-model assessment of the Global Warming Potential of hydrogen. 2023; *Atmospheric Chemistry and Physics*. Climate consequences of hydrogen emissions. 2022; Warwick, et al. Atmospheric implications of increased hydrogen use. 2022; *Communications Earth & Environment*. Climate benefit of a future hydrogen economy. 2022; *International Journal of Hydrogen Energy*. Global modeling studies of hydrogen and its isotopomers using STOCHEM-CRI: Likely radiative forcing consequences of a future hydrogen economy. 2020. *Global Environmental Change*. Emission scenarios for a global hydrogen economy and the consequences for global air pollution. 2011.
[45] General Electric. Hydrogen for Power Generation. 2022.

Calculating the expected downstream CO_2e emissions from all of the potential hydrogen delivery chains from the production facility to users is beyond the scope of this analysis. However, using a 5% loss rate, the compression energies noted by GE, and the average U.S. electricity grid CO_2 emission rate, this analysis estimates that the downstream carbon intensity of blue hydrogen will be in the range of 2.0 kg CO_2e/kg H_2 with hydrogen's 100-year GWP and 3.0 kg CO_2e/kg H_2 with its 20-year GWP, if not significantly higher.

These downstream carbon intensities are very conservative because they do not reflect any of the energy that would be required to liquify the hydrogen or re-boost its pressure to offset pipeline pressure losses experienced when it is transported as a gas. They also reflect only a 5% hydrogen leakage rate. But even so, they provide additional support for the conclusion that making "clean" and "low-carbon" blue hydrogen from natural gas is a myth.

A Partial Blue Hydrogen Life Cycle Analysis Masks Its True Carbon Intensity

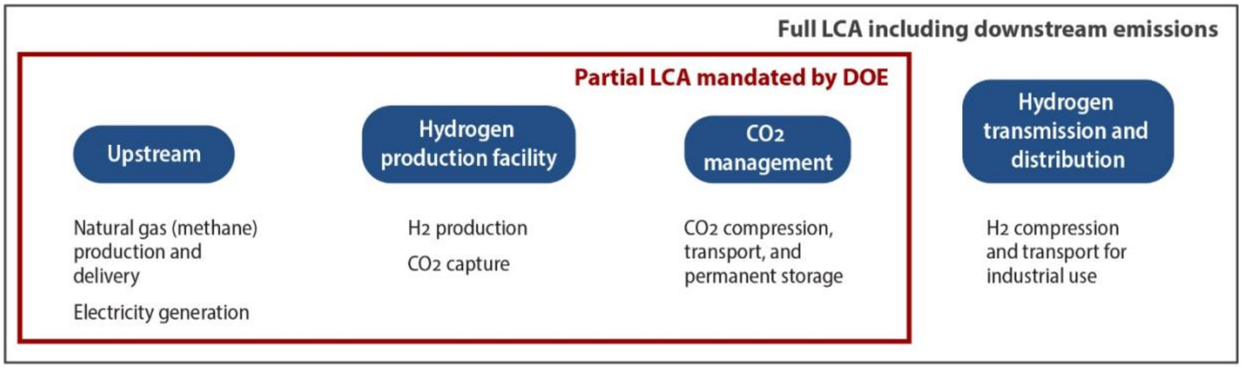
When people hear the term "life cycle analysis," or "LCA," they naturally assume that it means looking at the entire value chain from the production of the natural gas at a well to the final use of that hydrogen—also called a cradle-to-grave analysis. That is a reasonable assumption. Indeed, the team at Argonne National Laboratory that developed the GREET model has said that a "comprehensive life-cycle accounting methodology that takes all factors into account is required for holistic pursuit of clean hydrogen production."[46]

However, Congress has mandated that the life cycle analysis for hydrogen production should only cover from the well where the natural gas is produced (or the mine from where the coal comes from) to the back gate of the production facility—known as a well-to-gate analysis.

As shown in Figure 6 below, the emissions included in a well-to-gate GREET analysis are only those associated with upstream processes (e.g., electricity generation, fugitive emissions from the production and transportation of the methane or coal), the emissions at the hydrogen production facility, and only those downstream processes associated with transporting and sequestering the captured CO_2.

[46] Argonne National Laboratory. Hydrogen Life-Cycle Analysis in Support of Clean Hydrogen Production. 2022.

Figure 6: The Life Cycle Analysis (LCA) Required for Blue Hydrogen Is Only Partial



Source: DOE draft Clean Hydrogen Production Standard Guidance, IEEFA analysis.

Given these parameters, a life cycle analysis for blue hydrogen is really only a partial analysis. It does not include the downstream greenhouse gas emissions associated with the hydrogen after that hydrogen leaves the gate of the production facility. It leaves out the direct emissions associated with compression, liquefaction, transport, usage and other aspects of the hydrogen and the electricity needed to drive these processes.

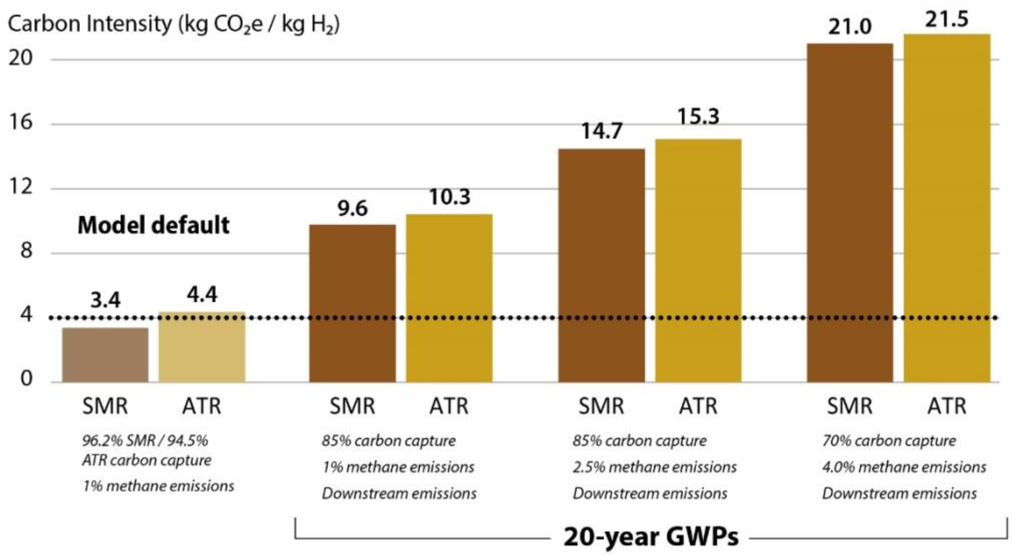
Results

When DOE GREET model defaults are used to estimate the carbon intensity of blue hydrogen, projects seem clean, i.e., they meet (or in the case of ATR, almost meet) the government's clean hydrogen standard of 4.0 kg CO_2e/kg hydrogen. However, the carbon intensity for a methane-based blue hydrogen project is very sensitive to changes in some of the key assumptions in the GREET model. This analysis only addressed four key assumptions: GWP for methane, upstream methane emission rates, carbon capture rates, and downstream emissions. Adjusting any of these assumptions, individually or in combination, leads to higher carbon intensities for blue hydrogen than those from using the default values in the GREET model.

For example, the total carbon intensity of blue hydrogen rose by an average of 0.9 kg CO_2e/kg hydrogen for every percentage point increase in the assumed upstream methane emission rate even when based on lower 100-year GWPs. Using 20-year GWPs, the impact of higher upstream emissions is even greater—the total carbon intensity jumps an average of 2.5 kg CO_2e/kg hydrogen for every percentage point increase in the assumed methane emission rate.

Figure 7 below compares the carbon intensity of using SMR and ATR to produce blue hydrogen with more realistic assumptions, including 20-year GWPs for methane and hydrogen.

Figure 7: Range of Carbon Intensities Reflecting 20-year GWPs and More Realistic Real-world Assumptions About Methane Emissions, CO_2 Capture Rates and Downstream Hydrogen Emissions

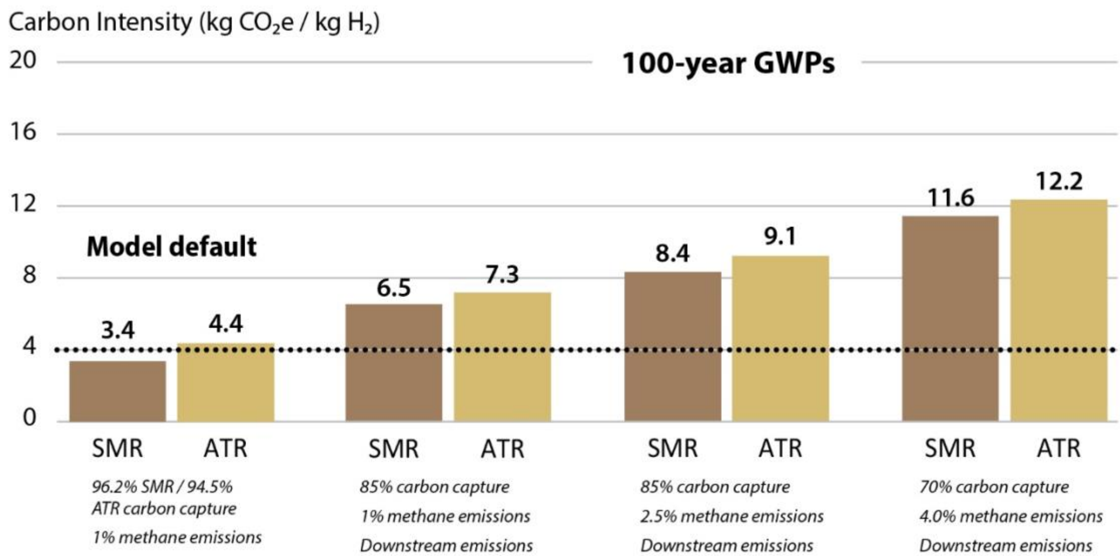


Source: IEEFA runs with DOE's GREET model.

As can be seen, using 20-year GWPs with a more realistic 85% carbon capture rate and a 2.5% upstream methane emission rate produces carbon intensities for blue hydrogen between three and four times more than DOE's clean hydrogen standard.

Even with 100-year GWPs, blue hydrogen's carbon intensity would be between two and three times more than the DOE standard, as shown in Figure 8.

Figure 8: Range of Carbon Intensities Reflecting 100-year GWPs but More Realistic Real-world Assumptions About Methane Emissions, CO_2 Capture Rates and Downstream Emissions



Source: IEEFA runs with DOE's GREET model.

The results of the GREET model runs used in this analysis are shown in Table 2 on the following page.

Table 2: Carbon Intensity Depending on Carbon Capture, Upstream Methane Emissions, GWP and Downstream Hydrogen-related Emissions

Steam Methane Reforming				Autothermal Reforming			
	Upstream Methane Emissions Rate				Upstream Methane Emissions Rate		
	1% (GREET default)	2.5%	4%		1% (GREET default)	2.5%	4%
100-year GWP; Partial life cycle analysis							
No carbon capture	11.6	13.3	14.9	No carbon capture	13.4	15.2	16.9
70%	6	7.9	9.6	70%	6.7	8.5	10.2
85%	4.5	6.4	8.1	85%	5.3	7.1	8.8
96.2% (GREET default)	3.4	5.2	7	94.5% (GREET default)	4.4	6.2	7.9
100-year GWP; Life cycle analysis + some downstream emissions							
No carbon capture	13.6	15.3	16.9	No carbon capture	15.4	17.2	18.9
70%	8	9.9	11.6	70%	8.7	10.5	12.2
85%	6.5	8.4	10.1	85%	7.3	9.1	10.8
96.2% (GREET default)	5.4	7.2	9	94.5% (GREET default)	6.4	8.2	9.9
20-year GWP; Partial life cycle analysis							
No carbon capture	13.5	18.2	22.6	No carbon capture	15.4	20.4	25.2
70%	8.1	13.1	18	70%	8.8	13.8	18.5
85%	6.6	11.7	16.5	85%	7.3	12.3	17.1
96.2% (GREET default)	5.5	10.5	15.4	94.5% (GREET default)	6.4	11.4	16.2
20-year GWP; Life cycle analysis + some downstream emissions							
No carbon capture	16.5	21.2	25.6	No carbon capture	18.4	23.4	28.2
70%	11.1	16.1	21	70%	11.8	16.8	21.5
85%	9.6	14.7	19.5	85%	10.3	15.3	20.1
96.2% (GREET default)	8.5	13.5	18.4	94.5% (GREET default)	9.4	14.4	19.2

Not a Worst-case Analysis

It is important to emphasize that these results do not reflect potential worst-case circumstances. It is certainly reasonable to expect that a blue hydrogen production facility could capture less than 70% of the CO_2 it creates, given the uncertain state of capture technology. It also is not unreasonable to expect that the upstream methane emissions from some blue hydrogen production facilities could be more than 4% especially when the variation in regional methane emission rates at existing gas-producing basins, shown in Table 1, is considered. In addition, we have assumed only a 5% downstream hydrogen leakage rate in our calculations, even though the actual level of hydrogen leakage from compressors, storage and pipeline infrastructure is currently unknown. Finally, we have not assumed any CO_2 leakage beyond the low levels assumed in the GREET model. Any of these circumstances, either individually or combined, could lead to higher—perhaps even substantially higher—carbon intensities for blue hydrogen than this analysis has shown.

Conclusion: Blue Hydrogen Is Not Clean or Low-Carbon and Never Will Be

This analysis has examined the carbon intensity of blue hydrogen over a range of production technologies, methane leak rates, 20-year and 100-year global warming potentials, and CO_2 capture rates. It also has included conservative estimated downstream emissions related to the compression, storage and transmission of hydrogen from the production facility to the site of its ultimate use.

Our conclusions are:

1. Contrary to the claims of blue hydrogen proponents, the fuel is not clean or low-carbon, and it never will be.

2. Unless you accept all of the unrealistic default assumptions built into the DOE GREET model, producing blue hydrogen from natural gas is shown to be dirty and high-carbon, with carbon intensities potentially as high as five times the DOE's 4 kg CO_2e/kg H_2 Clean Hydrogen Production Standard.

3. There is a significant risk that the support and funding of blue hydrogen projects by federal and state governments and investors will make global warming worse because projects built in the coming years will continue to emit significant amounts of greenhouse gases into the atmosphere for decades.

4. Neither the U.S. federal government nor state governments should fund dirty blue hydrogen production projects.

About IEEFA

The Institute for Energy Economics and Financial Analysis (IEEFA) examines issues related to energy markets, trends and policies. The Institute's mission is to accelerate the transition to a diverse, sustainable and profitable energy economy. www.ieefa.org

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