Recommendations for a stringent ISO standard on the GHG emissions from blue hydrogen production

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The ISO standard needs clear requirements for the climate impacts associated with upstream emissions and carbon storage

Blue hydrogen can pose considerable climate risks due to upstream GHG emissions (see new DNV analysis following). Another risk is potential leakage of carbon dioxide from the storage sites. It is crucial for any relevant standard, such as the IPHE methodology that is currently being established into an ISO standard, to properly account for these issues. We thus provide two recommendations for such a standard of blue hydrogen:

(1) Set clear and stringent requirements for the GHG emissions associated with the upstream natural gas value chain with respect to measuring, monitoring, reporting, and verification.

- For example, the ISO standard could reference level 4 and level 5 reporting under the OGMP 2.0 framework.

(2) Set clear and stringent requirements for the permanence of carbon storage.

- For example, the ISO standard could reference the *Carbon Capture and Sequestration Protocol* under California's Low Carbon Fuel Standard program

Third-party verification and public reporting would enhance the credibility of the measurement.

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Blue hydrogen can pose a climate risk and requires an ISO standard with strict guidelines

The Methodology for Determining the Greenhouse Gas Emissions Associated with the Production of Hydrogen developed by the International Partnership for Hydrogen and Fuel Cells in the Economy (IPHE) in 2021 (hereafter referred as “IPHE methodology”) is currently being established into an International Organization for Standardization (ISO) standard (1). However, loopholes in the IPHE methodology for blue hydrogen produced from fossil gas combined with carbon capture and storage (CCS) means that the true GHG impact of these hydrogen pathways may not be properly accounted for within the standard. We address these issues here to inform the ISO standard process.

To accurately account for the climate impact of hydrogen, such a standard must have stringent rules and requirements. **Blue hydrogen can pose a climate risk for two main reasons**:

(1) **The greenhouse gases**, including methane leakage, associated with the upstream natural gas extraction, processing, and transportation, and

(2) the secure storage of **carbon dioxide (CO_2)** from the waste streams of hydrogen production.

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Upstream GHG emissions are important, two studies show

A recent study from DNV (see attached) highlights that upstream GHG emissions are a critical factor impacting the climate performance of blue hydrogen. The IPHE methodology does not provide stringent requirements for upstream GHG emissions. It allows the use of emission factors provided by gas suppliers without any requirements on site specific data verification. Alternatively, the hydrogen producers may use the National Greenhouse Accounts emission factors.

Even small quantities of methane leakage in the natural gas value chain can have strong impacts on hydrogen GHG intensity due to the high climate forcing impact of methane**,** and yet they are very inconsistently reported by companies, pointed out by DNV. These findings complement a 2021 ICCT study, which includes findings from a literature review showing that upstream methane leakage can vary from less than 1% to as high as 20% (2). A 20% leakage rate can lead to higher than 90 gCO_2e/MJ (11 $kgCO_2e/kg\ H_2$) life-cycle GHG emissions from blue hydrogen, worse than fossil fuels. Moreover, as noted in the DNV study, different methodologies for measuring the upstream emissions can lead to very different leakage estimates. The National Greenhouse Accounts factors referenced in the IPHE methodology is found to underestimate real methane emissions (3).

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The ISO standard should properly account for upstream GHG emissions

Our first recommendation for the hydrogen IPHE methodology:
Set clear and stringent requirements for upstream methane emission measuring, monitoring, reporting, and verification.

The IPHE methodology could require hydrogen producers to get natural gas only from suppliers following a stringent international methane measuring and reporting standard, such as the Oil and Gas Methane Partnership (OGMP) 2.0 framework. The level 4 and level 5 reporting under the OGMP 2.0 framework requires source-level and site-level measurement throughout gas value chain. The proposed *Regulation on methane emissions reduction in the energy sector* by the European Commission is built on level 4 and level 5 reporting requirements under the OGMP 2.0 framework. This framework provides detailed guidelines on how to measure methane emissions, including leakage, and the reporting of methane emissions on an intensity basis. Besides having robust measuring and reporting requirements on methane emissions, it would also be necessary for the IPHE methodology to require the verification of the measurements from an independent, third-party organization, which could be complemented with public reporting to encourage greater transparency. The standard could also provide a default methane emissions value when value chain certification is demonstrably not feasible. This default value could be set at a relatively high value to motivate producers to present real, independently verified values.

Carbon capture and storage (CCS) from blue hydrogen production

As for carbon capture and storage (CCS), as shown in the DNV report, there are three primary carbon waste streams during blue hydrogen production.
Typically blue hydrogen producers using natural gas with steam methane reforming (SMR) only capture carbon from one of these waste streams, thus capturing only around 55% of the CO_2. As shown in both the DNV report and ICCT's 2021 LCA study, only capturing carbon from one of the waste streams means blue hydrogen provides very little, if any, GHG benefit relative to fossil fuels. Further, even when capturing most of the waste CO_2 from SMR, the stored CO_2 could leak in various ways and can be significant and long-term, thus undermining the permanence of the sequestration (4). The IPHE methodology requires the reporting of fugitive CO_2 emissions from storage within the reporting period. However, it does not provide guidelines on how to measure CO_2 leakage and it is not clear if the reporting period would be able to capture leakages occurring beyond the reporting period.

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Recommendations on CCS in the ISO standard

Our second recommendation is for the ISO standard to set clear and stringent requirements for the permanence of carbon storage. The IPHE methodology could be strengthened with adequate requirements to ensure the risk management and long-term viability of carbon storage. For example, the IPHE methodology could refer to the *Carbon Capture and Sequestration Protocol* developed by the California Air Resources Board under its Low Carbon Fuel Standard program. This protocol has explicit requirements for permanence certification of CCS projects including third-party review. Particularly, project developers are required to conduct a site-based risk assessment on CO_2 leakage over 100 years after the injection with an emergency and remediation plan. The protocol also specifies the techniques for CO_2 monitoring.

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Other indirect climate impacts of blue hydrogen

Besides the above-mentioned two risks of blue hydrogen that could be better addressed under the IPHE methodology, blue hydrogen can also cause indirect climate impacts that are more complicated and harder to measure. It is likely in many cases that captured CO_2 from hydrogen production is used to enhanced oil recovery (CO_2-EOR), which is by far the most common form of carbon storage. This means the blue hydrogen plant would contribute to the extraction and production of more oil and therefore, to the release of more CO_2 emissions into the atmosphere. While the magnitude of the increase in GHG emissions from increased oil consumption compared to the GHG savings from storing the CO_2 is unknown, there is a potential concern that more CO_2 would end in the atmosphere, having a negative impact on the climate. It is also possible that the oil producer might switch sourcing its CO_2 supply to the blue hydrogen plant from another industry. That other industry (from which the oil producer had originally procured the CO2) may then end releasing its CO_2 to the atmosphere if it does not find another customer to purchase and store its CO_2. If this happens, the CO_2 emissions from the replaced industry would entirely offset the CO_2 savings from performing CCS at the hydrogen plant. The IPHE methodology does not account for these indirect impacts.

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WHEN TRUST MATTERS

Review of Greenhouse Gas Emissions from Blue Hydrogen

Authors: Mark Fisher, Steven He, Stuart Blackburn, Claas Hülsen, Sarah Kimpton

23 June 2023

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Executive Summary

Executive Summary

This report provides insight into the greenhouse gas (GHG) emissions from the production of blue hydrogen. Quantification of the real GHG footprint requires availability of reliable data on emissions upstream of the reformer.

Blue hydrogen carbon intensity depends on the full value chain:

The value chain for blue hydrogen production may differ from location to location due to different gas fields, upstream processes, transport modes and reforming processes. Each of these elements can influence significantly the GHG footprint.

The accuracy of GHG emission estimates for hydrogen production from natural gas with CCS (blue hydrogen) also depends on model assumptions and methodological choices. It is particularly important to consider the blue hydrogen production technology, the upstream emissions from natural gas supply, and the chosen metric for measuring global warming potential (GWP) over a specified timeframe.

Data on GHG emissions along the value chain:

DNV has analysed a wide selection of publicly available data alongside calculation from first-principles to assess the range of emissions intensity figures presented in literature. Several studies aiming to quantify the GHG emissions impact from the natural gas value chain are available. However, all studies raise concerns over the accuracy and reliability of the figures produced due to a lack of transparent data and lack of accounting for methane emissions.

Transparent reporting is essential to quantify emissions properly:

Our calculations show that the GHG emission intensity for blue hydrogen production may vary from less than 1 $kgCO_2e/kgH_2$, to more than 10 $kgCO_2e/kgH_2$. This implies that it will be critical for blue hydrogen producers to provide transparency to the emission calculations and the underlying data to deliver confidence that the hydrogen is produced and delivered with low GHG emissions. This requires reliable and consistent reporting of emissions for each part of the value chain. Special attention should be placed on quantification of methane emissions along the gas supply chain.

1. Hydrogen and rationale for blue hydrogen

This report provides an overview of the blue hydrogen production value chain and the potential Greenhouse Gas (GHG) emissions that can be associated along the value chain.

Background and scope of the study

This short study has been written by DNV to explain and evaluate the possible GHG emissions that come with the production of blue hydrogen.

Logic of the report

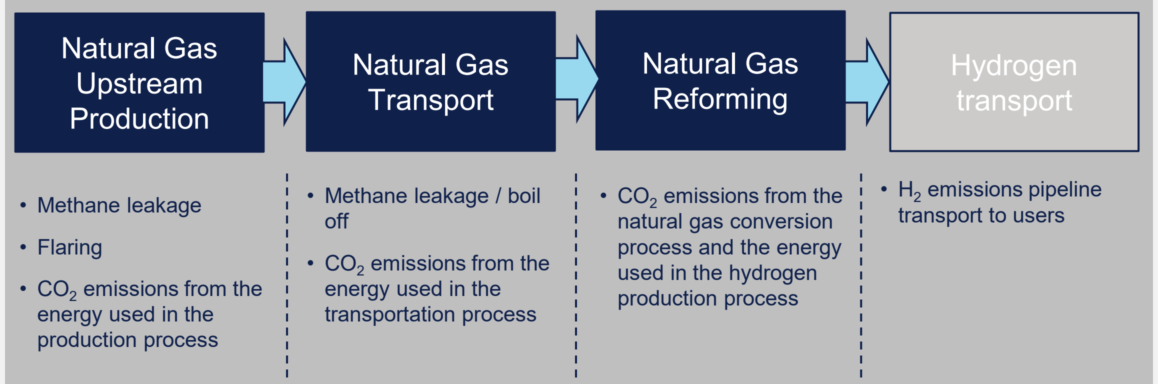
After this introductory chapter, our analysis follows the logic set out below:

- Chapter two explains the blue hydrogen production value chain. Possible process alternatives that have an impact on the GHG footprint will be explained at a high level to provide the reader with the necessary process knowledge.
- Chapter three defines the possible ranges of GHG emissions across the whole blue hydrogen value chain.
- Chapter four explains, as a conclusion of the analysis, what is required to produce and deliver blue hydrogen with a carbon intensity lower than the thresholds set for low-carbon or green hydrogen production.

System boundaries

For this report we have set out the system boundaries as shown in the diagram opposite. This report does not include life cycle emissions associated with the construction and decommissioning of the production facilities. It does include scope 1 and 2 emissions from the production, transport and reforming processes. While emissions downstream of the hydrogen production process are not included in our study, it is noted that hydrogen is an indirect greenhouse gas, and that emissions related to transport from centralised facilities to end users should be considered in life-cycle assessments.

When evaluating any methane-based mitigation options such as blue hydrogen, the choice of GHG emission metric used to compare the impact of methane emissions to CO_2 emissions and other greenhouse gases is important. The most common metric is the Global Warming Potential (GWP) of a specific greenhouse gas.



Source: DNV

Blue hydrogen will generally have a larger greenhouse gas footprint compared to green hydrogen since not all emissions from hydrogen production can be abated. However, the actual emissions will vary greatly depending on the chosen technologies and processes within the entire value chain.

1. Hydrogen and rationale for blue hydrogen

Various studies show hydrogen as an energy vector will be needed in the future to decarbonize sectors with a high energy intensity.

Hydrogen as an energy vector for decarbonisation

Hydrogen has been used in large quantities for well over 100 years as a chemical feedstock, in fertiliser production and in refineries. However, the use of hydrogen as an energy carrier is negligible. Hydrogen is now receiving increased focus as a potential low-emission energy vector and regarded as a critical component in global efforts to mitigate climate change. However, current hydrogen production has a significant carbon footprint. The production of hydrogen must therefore be decarbonized – currently at high cost – before it can play a prominent role in the drive to decarbonize the energy system. Hydrogen has significant cost, complexity, efficiency, and often safety disadvantages compared with the direct use of electricity. However, for many energy sectors, the direct use of electricity is not viable. Instead, hydrogen and its derivatives such as ammonia, methanol and e-kerosene are the prime low-carbon contenders. Further information from DNV on the role of hydrogen in the energy transition is available, see references below.

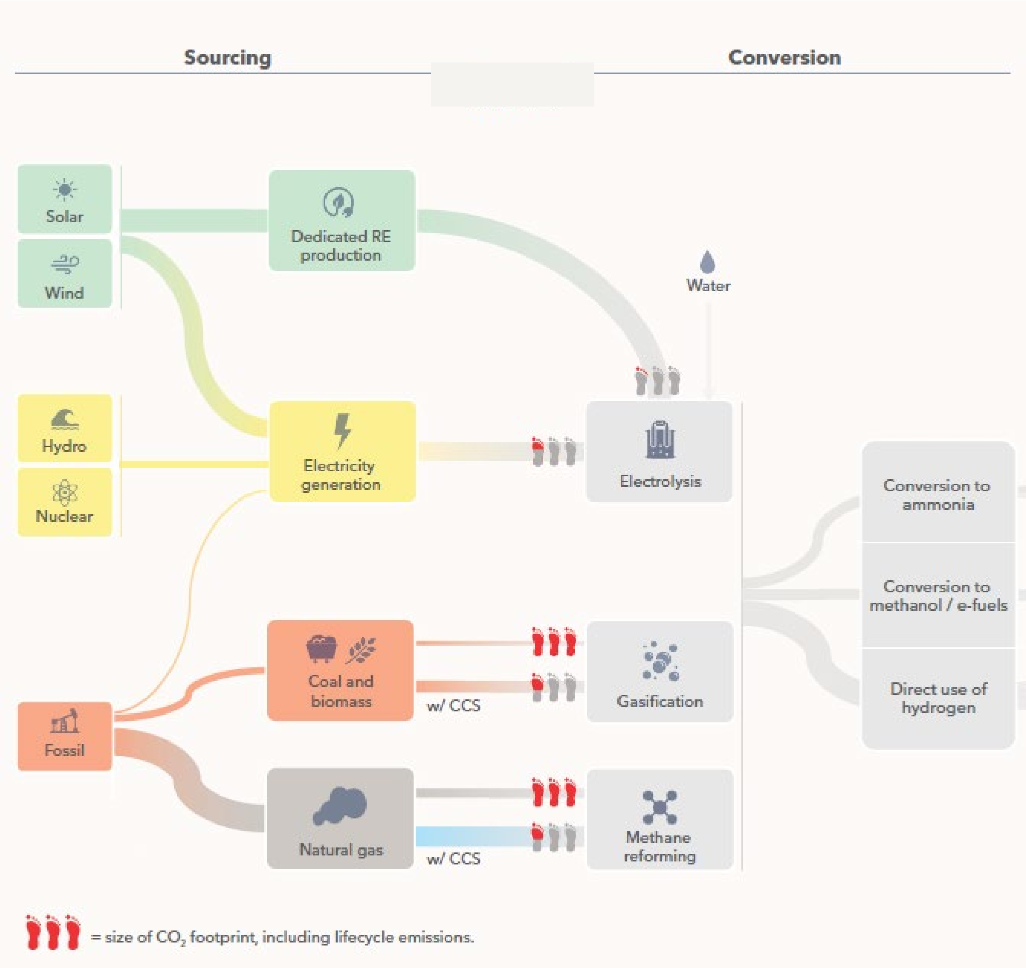
Hydrogen does not occur in a pure form naturally and it needs to be produced. There are two sources of hydrogen – from water (H_2O) or from hydrocarbons (usually fossil fuels comprising hydrogen and carbon):

1. To produce hydrogen from water, low-carbon electricity is used to split water molecules into hydrogen (H_2) and oxygen (O_2) in an electrolyser; oxygen is a byproduct. No carbon dioxide is produced (apart from the emissions that come with the set up of the infrastructure). This is often known as green hydrogen.
2. To produce hydrogen from hydrocarbons (usually natural gas), a reforming process is used to split the hydrocarbons into carbon dioxide and hydrogen. For the hydrogen to be low-carbon (or blue):
   i. The carbon dioxide produced from the reforming process needs to be captured, transported and then stored permanently underground – this process is known as carbon capture and storage (CCS).
   ii. Any GHG emissions associated with the production, processing and transport of the fossil fuel need to be minimized and included in the assessment of the carbon intensity of the hydrogen.

References

DNV Energy Transition Outlook [Energy Transition Outlook – DNV]

DNV Hydrogen Forecast to 2050 [Hydrogen forecast DNV]



Source: DNV

1. Hydrogen and rationale for blue hydrogen

There are many different types of emissions that have a global warming potential – here we consider the two largest sources for blue hydrogen production.

Climate change impacts

DNV believes that both green and blue hydrogen have a role in decarbonising the global energy system. However, all types of hydrogen need to be low-carbon to contribute to legally binding internationally agreed targets adopted as part of the Paris Agreement. The climate change impacts of hydrogen production from natural gas with CCS (blue hydrogen) depend on several processes along the entire value chain, and on many assumptions and methodological choices. It is particularly important to consider the blue hydrogen production technology, the upstream emissions from natural gas supply chains, and the metric for measuring global warming potential (GWP) over a specified timeframe.

This brief elaborates on these three aspects, gathering data for different blue hydrogen production technologies and for upstream emissions from natural gas supply chains in different regions. It then combines this data in various combinations and compares it to the thresholds for GHG footprint.

Thresholds for low, medium and high emissions associated with hydrogen production

The World Business Council for Sustainable Development (WBCSD) recommends the following thresholds (on a full life-cycle basis):

Category	Maximum allowed emissions	Units	Maximum allowed emissions	Units
Reduced-carbon hydrogen	6	kg CO_2e/kg H_2	50	g CO_2e/MJ H_2 (net)
Low-carbon hydrogen	3	kg CO_2e/kg H_2	25	g CO_2e/MJ H_2 (net)
Ultralow-carbon hydrogen	1	kg CO_2e/kg H_2	8.3	g CO_2e/MJ H_2 (net)

The reduced-carbon hydrogen threshold is only relevant as a steppingstone to achieving lower carbon hydrogen for existing higher intensity production installations.

The EU taxonomy sets the greenhouse gas emissions threshold for hydrogen production at 3 t CO_2eq/t H_2 on a lifecycle basis. This corresponds to the low-carbon threshold as defined by WBCSD.

Global warming potential (GWP)

GWP is a metric developed and adapted by the Intergovernmental Panel on Climate Change to account for trade-offs between different greenhouse gases. It compares the future global warming caused by an idealized pulse of emissions of a specific greenhouse gas. The GWP aggregates impacts over time, hence the estimation requires a specific time horizon over which future warming is quantified and compared (e.g. 20 years in GWP20 and 100 years in GWP100). Given the short atmospheric lifetime of methane of roughly 12 years, the choice of time horizon has a strong impact on its GWP and the results of our greenhouse gas footprint analysis.

The IPCC 6th Assessment Report (AR6) quote the following GWP figures for methane:

- GWP(20) = 82.5 ± 25.8 (after 20 years, methane is 82.5 times more potent than an equivalent kg of carbon dioxide)
- GWP(100) = 29.8 ± 11 (after 100 years, methane is 29.8 times more potent than an equivalent kg of carbon dioxide).

Why have we considered only CO_2 and CH_4?

Other greenhouse gases, such as NO_X, HFCs, and CFCs, are more potent climate gases (measured in GWP per tonne of gas emitted) and more persistent than both CO_2 and methane. However, we do not consider these in our report and there are two main reasons for this. Firstly, the energy sector is not a significant contributor to these emissions. Secondly, the quantities of these greenhouse gases are low, despite their high potency.

Hydrogen itself is not a direct GHG, but its chemical reactions adversely affect the amounts of greenhouse gases such as methane, ozone and aerosols in the atmosphere. It is prudent therefore to ensure that all processes downstream of the hydrogen production facility (whether green or blue) limit the amount of hydrogen that is emitted to the atmosphere.

Units

Emissions may be expressed using a variety of units including mass and energy units in terms of methane and hydrogen. When expressed in energy units (MJ) we have used the net or lower calorific values. For hydrogen, the net calorific value is 119.910 MJ/kg.

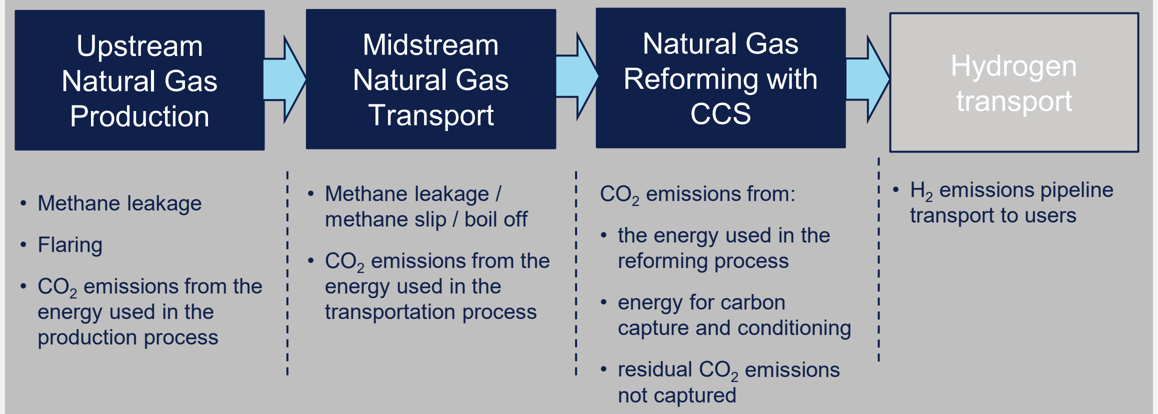
Source: DNV

2. Blue hydrogen value chain

Introduction to the blue hydrogen value chain

The gas value chain comprises various stages at which GHG emissions can occur – the emissions are mainly either methane or carbon dioxide.

- In this section we will focus on a description of the blue hydrogen value chain so that the reader gets a basic understanding of the entire process needed to produce blue hydrogen and also of the most common process alternatives that are today considered and that have an influence on the GHG emissions from the value chain.
- We describe the three major elements that need to be considered to understand the process. These are:
  - The **upstream production process**, where gas is taken out of natural reservoirs
  - The **transport** of the gas by pipeline or ship that may differ depending on the geographical location of the gas reserve
  - The **reforming process to produce hydrogen** from the natural gas and the capture of the carbon dioxide produced.
- We have not included:
  - The downstream hydrogen value chain but we do highlight that hydrogen can play an indirect role in global warming if it escapes into the atmosphere
  - The transport of the captured carbon dioxide to the geological long-term storage site



Source: DNV

2. Blue hydrogen value chain

2.1 Gas production from upstream onshore and offshore wells

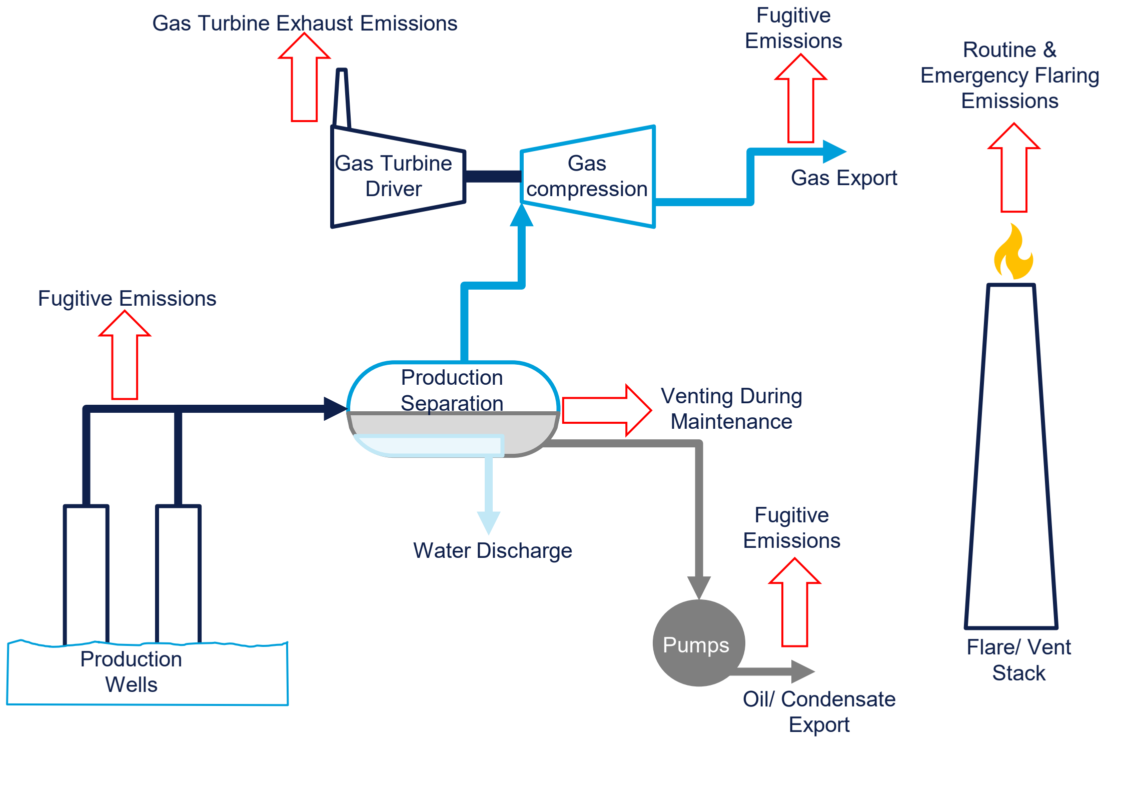
Upstream gas production is generally a case of separating gas from other produced fluids before conditioning at a processing plant.

Natural gas is mainly methane which is the simplest hydrocarbon comprising one atom of carbon and four atoms of hydrogen. Gas is produced around the world from hydrocarbon reservoirs deep underground – these are often a mix of hydrocarbons which are then initially separated into gases, associated oil and gas condensates, water and solids. The gases are compressed, liquids pressurised and water treated and discharged.

Gas and liquids can be exported through different routes or recombined, sometimes with the water as well, and sent to a processing plant by pipeline. At the processing plant gases are dehydrated, conditioned and blended to achieve the right specification (moisture content, calorific value, purity, etc.) for use.

At production, additional systems may be included to enhance recovery from the reservoir, to address particular hazards such as hydrogen sulphide and naturally occurring radioactive materials, and deal with high-levels of entrained solids. Systems for testing particular wells and to allow controlled depressurisation of the process system in routine and emergency situations also add to the complexity of the process systems. Offshore production systems (i.e. those used over water and out at sea) require an ability to be able to be installed using components that can be handled in areas with restricted access. This tends to increase the number of mechanical (flanged) joints in the process system. In conjunction with an aggressive corrosion environment, this means an increased risk of leaks and fugitive methane emissions if inspection and maintenance is not of a very high level.

In the diagram opposite, red arrows are used to indicate possible sources of GHG emission sources in the methane value chain - these consist mainly of flaring, venting and fugitive emissions. Increasingly, regulations are being used to minimise or mitigate GHG emissions – for example, corporate or national regulations that limit venting and flaring and/or the use of electrification of production processes such as compression.



Source: DNV

2. Blue hydrogen value chain

2.2 Gas transport value chain – pipeline transmission, storage and distribution in gaseous form

Natural gas can be transported by long-distance pipelines from point of production to energy markets, both nationally and internationally.

Options for long-distance transportation of natural gas

Once natural gas has been produced from geological hydrocarbon reserves and processed to sales gas quality, it needs to be moved to the energy markets and, ultimately, end-users.

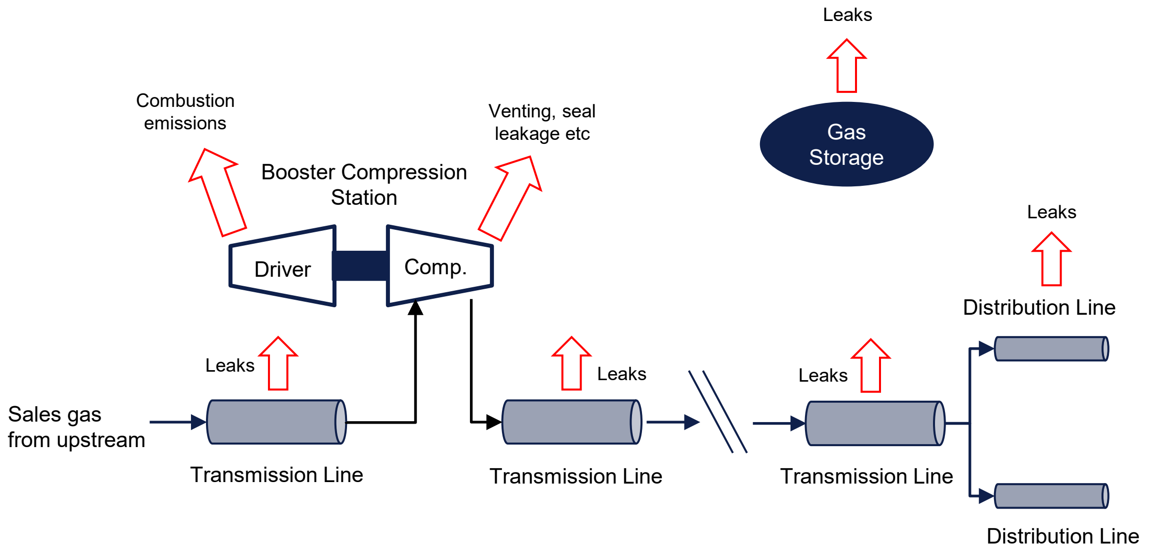
Most natural gas is exported via pipeline, with modern long-distance transmission systems spanning thousands of kilometres from wellhead to burner-tip. Pipeline transport is particularly advantageous when there are no significant obstacles between supply and demand, such as deep waters or mountainous terrain. However, natural gas transferred via pipeline connects two or more fixed points. To take advantage of other export market opportunities, natural gas can be converted to liquefied natural gas (LNG) and transported at low temperatures by specially designed ships.

Transport of natural gas by pipeline

Gas flows through a pipeline due to pressure differential. Long-distance transmission lines, operating up to approximately 100 barg, install regular booster compression stations placed every 100-200 km to overcome pipeline friction. The compression stations are a key source of carbon dioxide emissions from the combustion of natural gas, and they may also be a source of leaks, such as through compressor seals.

Typical GHG emissions sources are indicated in the diagram opposite by the red arrows. Efficiency of the overall system is usually measured through gas shrinkage metrics, which indicate the gas lost in the system. Gas-driven compressors are normally fuelled by the pipeline gas whilst fugitive emissions may occur throughout the system from compressor seals, piping design, metering and maintenance procedures.

As the demand for energy varies considerably throughout the year, seasonal storage is used by countries to economically satisfy peak demand. Gas is stored typically by injection into depleted hydrocarbon reservoirs, aquifers and salt caverns.



Source: DNV

2. Blue hydrogen value chain

2.2 Gas transport value chain – Liquefied Natural Gas (LNG)

Where natural gas reserves are geographically isolated from energy markets, LNG provides an economically viable solution to transport gas from stranded assets.

The need for LNG

A large proportion of natural gas production is geographically isolated from the energy markets. In order to provide access to key demand centres, whilst also creating flexibility for the seller to respond to demand in the global energy markets, liquefied natural gas is an economically viable solution to deliver large quantities of gas from remote locations. The high energy density of LNG means that transportation is more efficient, however the nature of the liquefaction process means that extra gas processing steps are required resulting in an overall higher carbon intensity.

By cooling natural gas to below -160°C at 1 atm, the volume reduces by a factor of 600, creating an economical method to flexibly store and transport energy globally. The three main steps in the LNG process are:

Liquefaction

Upstream gas is fed into the facility where it is purified to remove impurities such as carbon dioxide, water and heavy hydrocarbons that will cause issues during liquefaction by freezing in the cryogenic heat exchanger. The gas is sequentially cooled in the multi-stage exchanger, with the resultant liquified natural gas transferred to storage prior to ship loading. Boil-off gas (BOG), a mixture of mainly methane and nitrogen, is generated due to tank heat ingress. BOG is normally recovered and either returned upstream in the process to be re-liquified, supplied to the fuel gas system or sent to flare. Depending on the liquefaction technology, age of the facility, and ambient temperature, which influences system thermal efficiency, typically 8 – 12% gas shrinkage occurs i.e. 8 – 12% of the facility feed gas is used for energy at the facility. The primary energy expenditure and source of emissions will be the refrigerant compressors and, depending on the geographical location of the facility and availability of grid infrastructure, on-site electrical power generation. Opportunities for heat integration are being explored by developers (such as imported liquid CO_2) which would reduce the energy consumption of liquefaction facilities. However, the benefits that could be realised through utilisation of cold energy imports is likely to be limited due to the lower temperature of natural gas liquefaction, whilst the economic viability for importing cold energy is not clear.

Shipping

LNG is traded internationally and transported via large cargo ships (LNG carriers), which are specially designed to transport LNG below -160℃ and atmospheric pressure. LNG carrier scale has been steadily increasing over the last 20 years, from 160,000 m^3 in early 2000s, to the largest 260,000 m^3 Q-max vessel commissioned in 2011 for the Qatar LNG market. Two main types of cargo containment systems exist – the membrane-type (approximately 70%) and the moss-type and both aim to reduce boil-off gas (BOG). A typical range of 0.1 - 0.15% of the LNG cargo with boil off each day at sea, however modern ships with the membrane containment systems are quoted to reach as low as 0.08%. Older carrier designs would use the boil off gas and heavy fuel oil or marine diesel oil for propulsion, however more recent designs acknowledge that BOG is too valuable to burn and thus rely primarily on Marine Diesel Oil (MDO), with the BOG reliquefied and returned to the tanks. Shipboard carbon capture (SBCC) has been suggested as an effective transition solution to achieve significant reductions in carbon emissions before carbon-neutral fuels such as bio-LNG, methanol and ammonia are widely available. However, capture and storage on mobile offshore vessels presents challenges, such as availability of onboard storage capacity, CO_2 liquefaction power demand and the technical feasibility for retrofitting existing vessels.

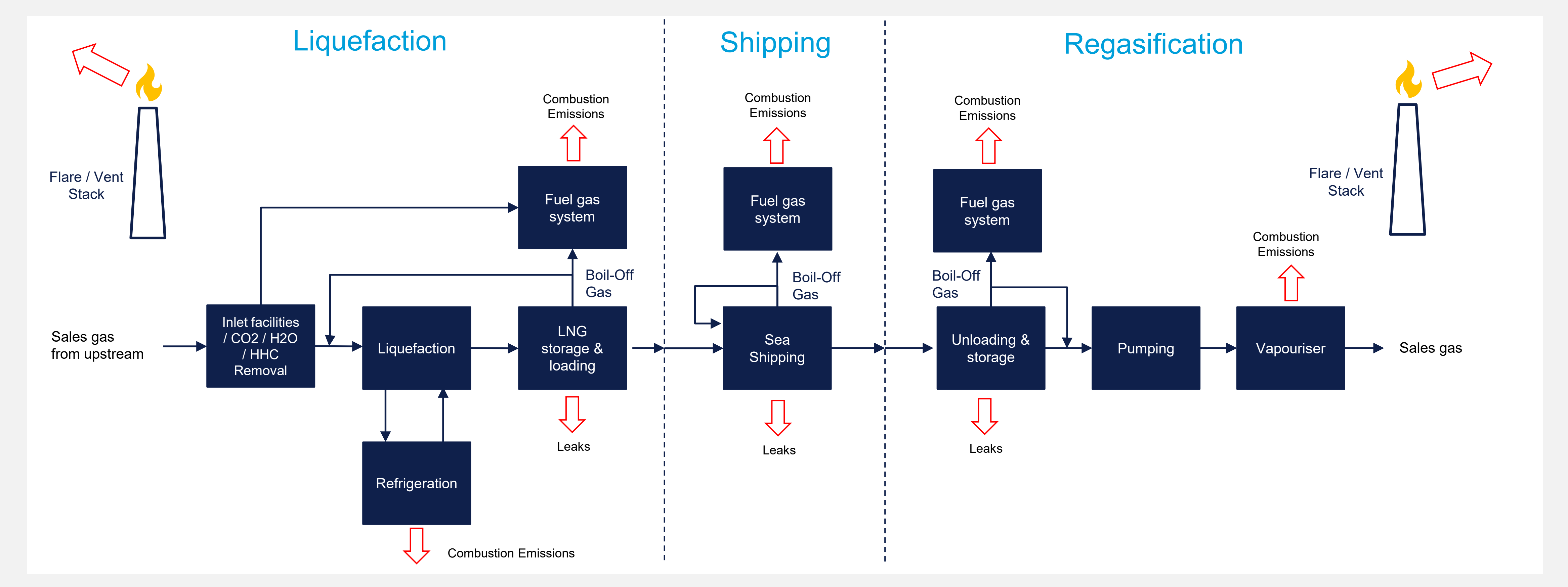
Regasification

LNG is received and unloaded from carriers to regasification terminal storage, which are located both onshore (90% of total regasification capacity) and floating offshore via Floating Storage and Regasification Units (FRSUs). The primary objective of the terminal is a storage and send out facility that can supply energy markets on demand. LNG is stored in thermally insulated tanks that limits heat ingress and BOG generation. In send out mode, LNG is pumped from the tank to export pressure before vaporisation in dedicated heat exchangers. In warm climates, Open Rack Vaporisers are common with ambient water temperature supplying sufficient temperature driving force. In colder climates, supplemental heat must be supplied through burning fuel gas in Submerged Combustion Vaporisers. Typically this results in a gas shrinkage of 1.5%. There are existing technologies which have been deployed at scale for regassification terminals to recover and utilise the high grade cold energy that otherwise would be lost. Power generation and air separation are techniques that could be considered for utilisation of this cold energy, with potential future use cases in cryogenic CO_2 capture and liquefaction.

2. Blue hydrogen value chain

2.2 Gas transport value chain – Liquefied Natural Gas (LNG)

The LNG value chain contains more processing steps compared to the pipeline value chain, which results in a higher emissions intensity.



2. Blue hydrogen value chain

2.3(i) Production of blue hydrogen from stream methane reformers

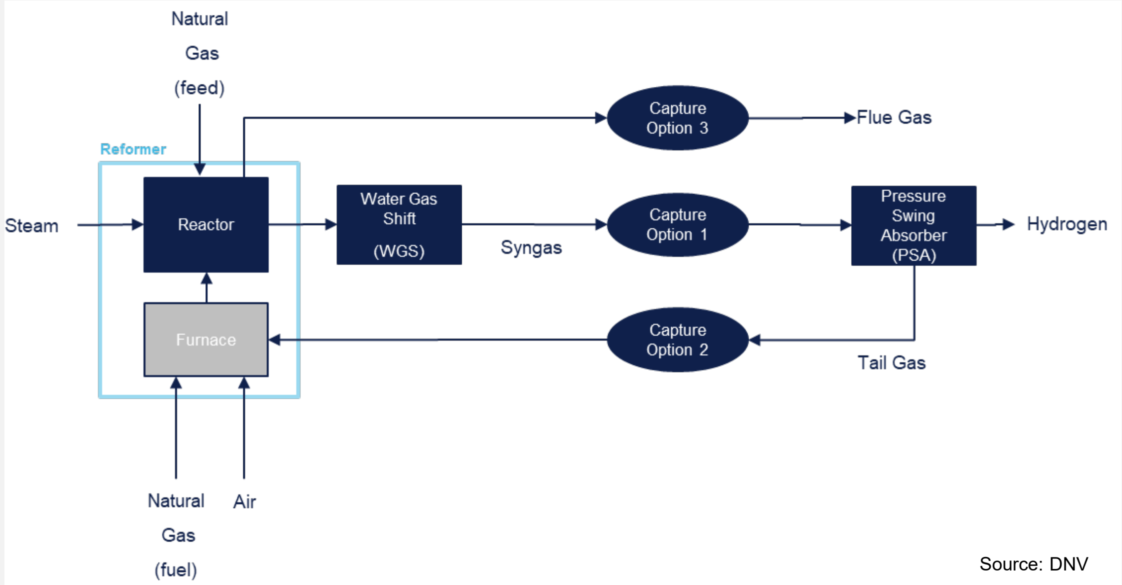
The two main ways of producing blue hydrogen at scale are steam methane reformation and autothermal reformation. In this section we explore the typical process plant layouts for these reforming technologies together with the options for carbon capture.

Steam methane reformation (SMR)

Simply explained, the SMR process works by introducing natural gas, mainly methane, and steam into a reactor, which is supplied by heat from a surrounding furnace. The furnace generates heat from combustion of natural gas along with excess air. Methane that has been converted to hydrogen and carbon monoxide is then sent through the water gas shift (WGS) reactor(s) to convert carbon monoxide to carbon dioxide. The pressure swing absorber (PSA) separates the hydrogen out from the syngas that exits the WGS process. There are several different carbon capture options for the SMR process:

- Capturing CO_2 from the syngas prior to the PSA
- Capturing CO_2 from the tail gas after the PSA
- Capturing CO_2 from the flue gas exiting the furnace

A flowsheet of the SMR process, along with the different CO_2 capture locations is shown opposite. If only capture option 1 (syngas) or option 2 (tail gas) are selected, then the overall capture rate is limited to a maximum of 60% as the emissions from the reformer flue gas are neglected. When including carbon capture from the flue gas (capture option 3) in addition to capture from the syngas or tail gas, the capture rate can reach around 95 to 96%. Other options to consider are electrical heating of the reformer and, in contrast, less natural gas would be required to produce H2 which would impact the CO2 footprint along the entire production chain.



Source: DNV

2. Blue hydrogen value chain

2.3(ii) Production of blue hydrogen from autothermal reformers

Autothermal reformers are less common than steam methane reformers but they are simpler and more efficient.

Autothermal reformation (ATR)

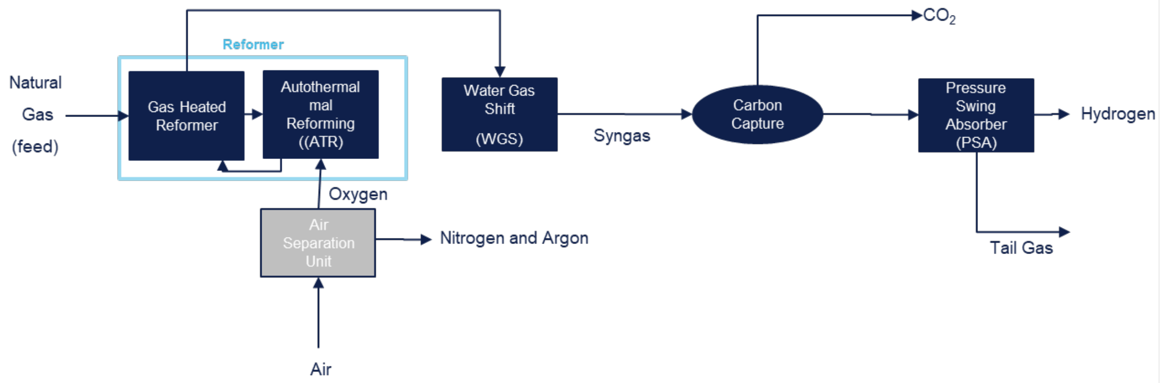
There is less commercial experience with ATR compared with SMR; however, the processes have some similarities as ATR is based on a combination of SMR and partial oxidation (POX) technology.

In an autothermal reformer (ATR), pure oxygen is used instead of air, making an air separation unit (ASU) necessary. The primary reformer in ATR differs from SMR in that the heat is supplied by the process itself, eliminating the need for a furnace. Otherwise, the process is similar, with WGS reactor(s), a capture plant, and PSA following the reformer.

For the ATR process, a gas heated reformer (GHR) can also be included for pre-heating and reforming some of the initial hydrocarbons. An example of the ATR process including GHR, and carbon dioxide capture is shown.

ATR has some advantages over SMR, such as lower operating pressure, and a smaller and more easily controllable system. It also provides benefits of better temperature control, lower energy requirements and easier start-up. A shortcoming of the ATR is the need for oxygen, rather than air combustion, as the oxygen production plant is a large investment, besides of requiring additional energy.

The carbon dioxide capture rate for hydrogen production from ATR is typically greater than 94%.



Source: DNV

2. Blue hydrogen value chain

2.4 CO_2 capture and storage

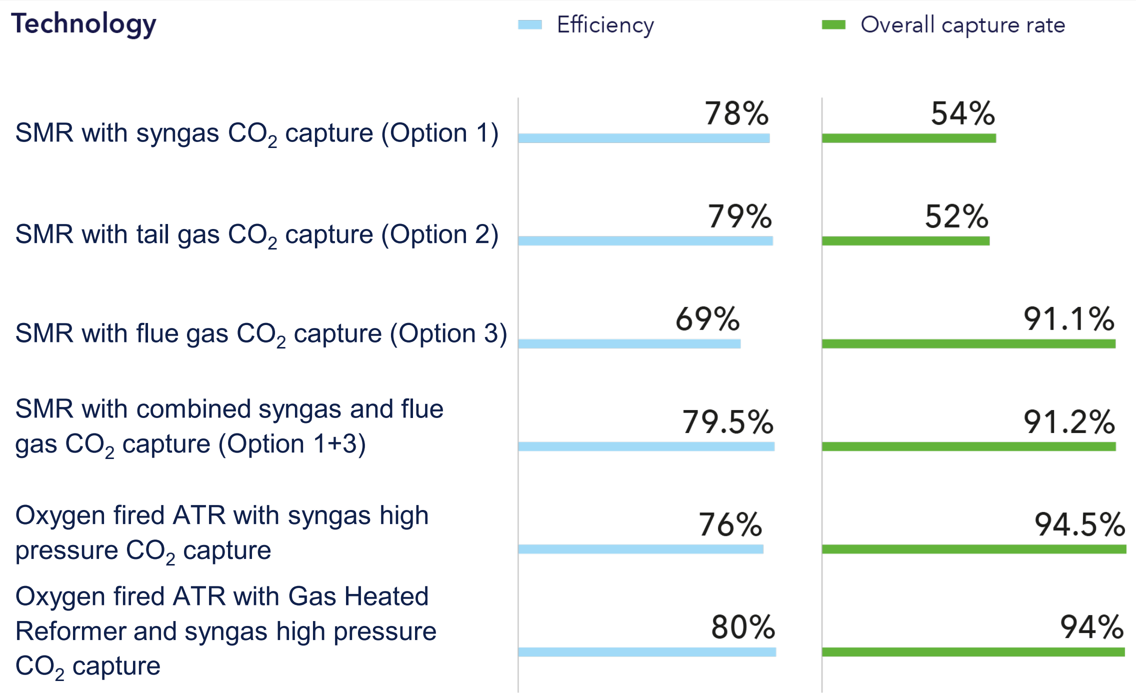
Comparing and contrasting blue hydrogen production technologies in terms of energy efficiency and emissions.

Prior to the Paris Agreement on reaching net zero emissions by 2050, hydrogen was dominantly produced using SMR without capture of carbon dioxide. Now, however, CCS is increasingly seen as a necessity for future hydrogen production from fossil fuel sources.

The figure to the right shows examples of achievable efficiency and capture rates for various configurations. The two ATR options deliver the highest overall capture rates, while SMR with syngas or tail gas carbon capture delivers the lowest overall carbon capture rates. Noting the differences in efficiencies for SMR with different capture options, combining capture option 1 and 3 is more efficient than solely having capture option 3, even though they reach approximately the same capture rate. This is because the low pressure steam is required when capturing carbon dioxide from flue gas, leading to a higher consumption of natural gas. When combining high pressure capture and low-pressure capture (capture option 1+3), waste heat from the reformer is used for power generation to produce low pressure steam. Combining the two capture options would, however, require electrical power import and two capture plants, making the increase in efficiency an expensive improvement.

SMR with the two combined capture options and ATR with GHR and CO_2 capture are the best options for efficiency. However, both options are relatively expensive – the combined capture in SMR because it requires two capture plants and the ATR because of the required air separation unit.

An overview of energy efficiencies higher heating value (HHV) and capture rates of SMR and ATR with CCS is shown in the figure opposite. The capture rate is the overall carbon capture rate for the whole process.



Source: DNV

2. Blue hydrogen value chain

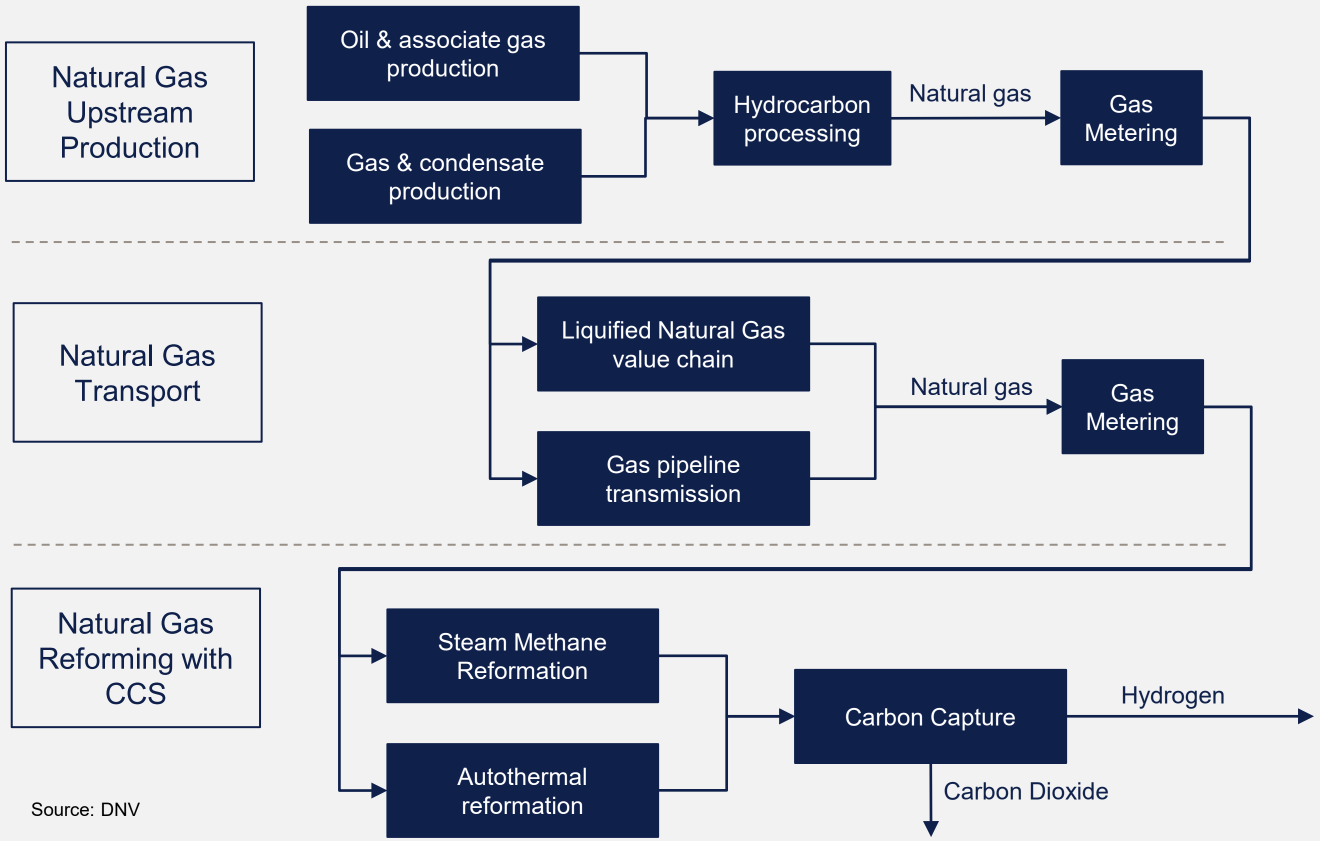
2.4 Summary and key takeaways

Value chains for blue hydrogen production can differ by hydrocarbon production properties, gas transportation modes, hydrogen production methods and carbon removal techniques that occur at various points.

A number of points have been raised from this section:

- The value chain for blue hydrogen production may differ from location to location due to different reservoirs, upstream processes, transport modes and reforming processes. The combination of each of these elements results in a significantly varying GHG footprint.
- In the upstream process the geology of the reservoirs, their age, co-production and other aspects matter and influence potential GHG sources.
- In the transport value chain, the transportation mode is an important consideration - LNG has a much higher emissions than pipeline transmission due to the increased energy requirements needed to liquify and re-gasify the natural gas.
- In the blue hydrogen production process, the location and efficiency of the capture process is important in balancing the energy consumption and the emissions reduction it delivers.
- Any standard for blue hydrogen production needs to carefully take into account the different processes that might be involved across the value chain. At each stage, each of the different value chain elements need to be monitored and measured in order to determine the full value chains GHG emissions.

In the following chapter, we will dive more deeply into the ranges of GHG emissions that can occur and we provide values for different combinations of the value chain elements that are observed in reality.



Source: DNV

3. Evaluation of possible GHG emissions alongside the value chain

3 GHG Emissions – introduction

Across the value chain there are large variations and uncertainties regarding emissions reporting. This is for a range of reasons but suggests that generic figures should be used with caution for decision making.

When building a set of GHG emissions for the blue hydrogen value chain, the main challenges include:

- Inconsistent reporting – this is particularly prevalent in the upstream part of the value chain.
- Lack of data – data gaps appear in all areas due to lack of public reporting.
- Limited experience with the technology – in the case of hydrogen production and the associated carbon capture systems, there is limited operational experience with these technologies at scale.

DNV has attempted to make use of the data in the most appropriate manner, ensuring consistency where possible. However, we have also been clear on the uncertainties and the broad range of results.

- Where data is used, this has either come from formal reporting by the emitter or from studies with strong provenance.
- The analysis covers each of the options presented in the previous section and reports them separately where possible.
- The output of the analysis is a set of charts showing the high, medium and low ranges for emissions in each part of the value chain and the impact on each of the range of options. Upper and lower thresholds have been defined based on the grouping of the data. For this reason, extreme outliers have been excluded. Medium values have been calculated using the median figure and includes the outliers.

Assumptions	Explanation
GHG protocol	All measurements have been made in line with the requirements of the Green House Gas Protocol (see next page).
Heating Value	Lower Heating Values (LHV) have been used consistently in our calculations although in some cases it is not clear which value has been used when developing some of the input data.
Global Warming Potential	A GWP100 for fossil Methane of 29.8 has been used in calculations consistent with the GHG Protocol AR6 from March 2023.
Energy carrier	It should be noted that across the value chain different energy carriers have been used. ▪ **Upstream**, methane has been used but this is complicated by the fact that liquids and gases are co-produced and separating emissions associated with gas production is problematic from the reported sources. ▪ **Midstream**, methane has been used consistently as processed natural gas is the input to this part of the value chain. ▪ **Downstream**, hydrogen has been used as the output from the reformation processes. The final aggregated output is presented in $gCO_2e/MJ_{Hydrogen}$
Scope 3 Emissions	These have been excluded from upstream emissions because separating those related to consumption of the product from those due to other reasons (such as contracted services) proved to be challenging to do consistently from the reported data.

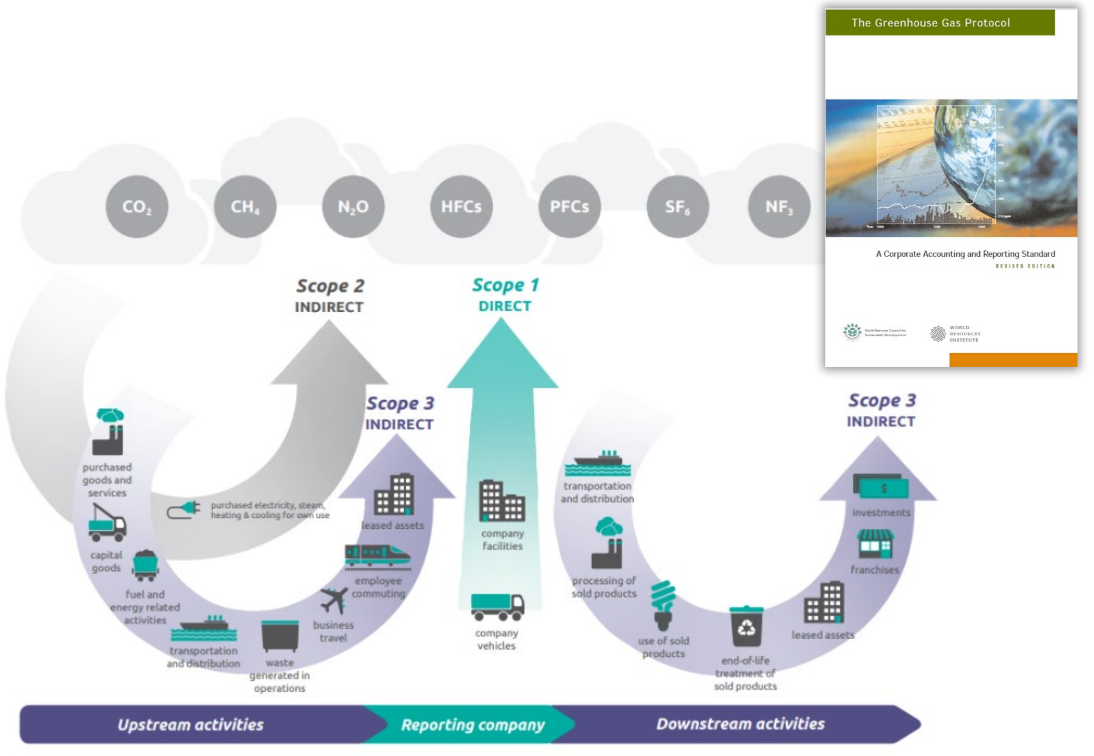
3. Evaluation of possible GHG emissions across the value chain

3.1 Metrics for evaluating GHG Emissions

The Green House Gas Initiative provides a recognised basis for reporting emissions with global warming potential. Whilst regularly quoted by companies as the basis for reporting, it is often applied in different ways resulting in inconsistent results.

World Business Council for Sustainable Development and World Resources Institute's Greenhouse Gas (GHG) Protocol provides a standard for GHG accounting and reporting. The revised edition is the starting point for most GHG reporting initiatives. It has some important aspects:

- **GHG Emissions** – The protocol requires reporting of substances that have a Global Warming Potential (GWP) in the atmosphere. Carbon Dioxide (CO_2) is used as the reference. GWP figures are regularly revised as the climate science evolves. Methane (CH_4) has a very high GWP100 around 29.8 that of CO_2, whilst hydrogen is increasingly being seen as having a GWP when present in the upper atmosphere.
- **Emissions Scopes** – Three main types of emissions are required to be reported as shown in the diagram on the right. Scope 1 emissions are directly from the company's activities. Scope 2 are related to energy the company purchases from other sources and consumes (such as electricity, natural gas, heat and steam). Scope 3 emissions are those indirectly resulting from the company's activities. These include contracted services (i.e. emissions generated by work done by other companies on behalf of the reporting company), but also includes the use of sold products and services. For upstream oil and gas producers, this Scope 3 category is generally the biggest source of GHG emissions, often estimated at 5 to 7 times the size of Scope 1 & 2 emissions. Accurate Scope 3 reporting is challenging as it requires significant data transfer between companies within value chains. The GHG Protocol currently allows Scope 3 emissions to be reported on a discretionary basis meaning they are often not reported.
- **Operational Boundaries** – Two main approaches are allowed for accounting of emissions within the GHG Protocol. *Control Approach* allows companies to report emissions where they have operational or financial control over an asset even if they do not own the asset (e.g. where the company has an operations and maintenance contract). The *Equity Share Approach* allows companies to allocate the emissions from an asset based on the proportion of the equity they own in the asset.



Source: WBCSD, WRI

As it is generic, the GHG Protocol is open to interpretation leading to inconsistency in reporting between companies. Industry groupings are working to provide consistent interpretations within their sectors.

3. Evaluation of possible GHG emissions alongside the value chain

3.2 GHG emissions from upstream onshore and offshore hydrocarbon production

Upstream gas production has seen big reductions in some emissions, but inconsistent reporting across the sector and operational factors mean there are large variations in the emissions intensity of methane feedstock.

Data Sources

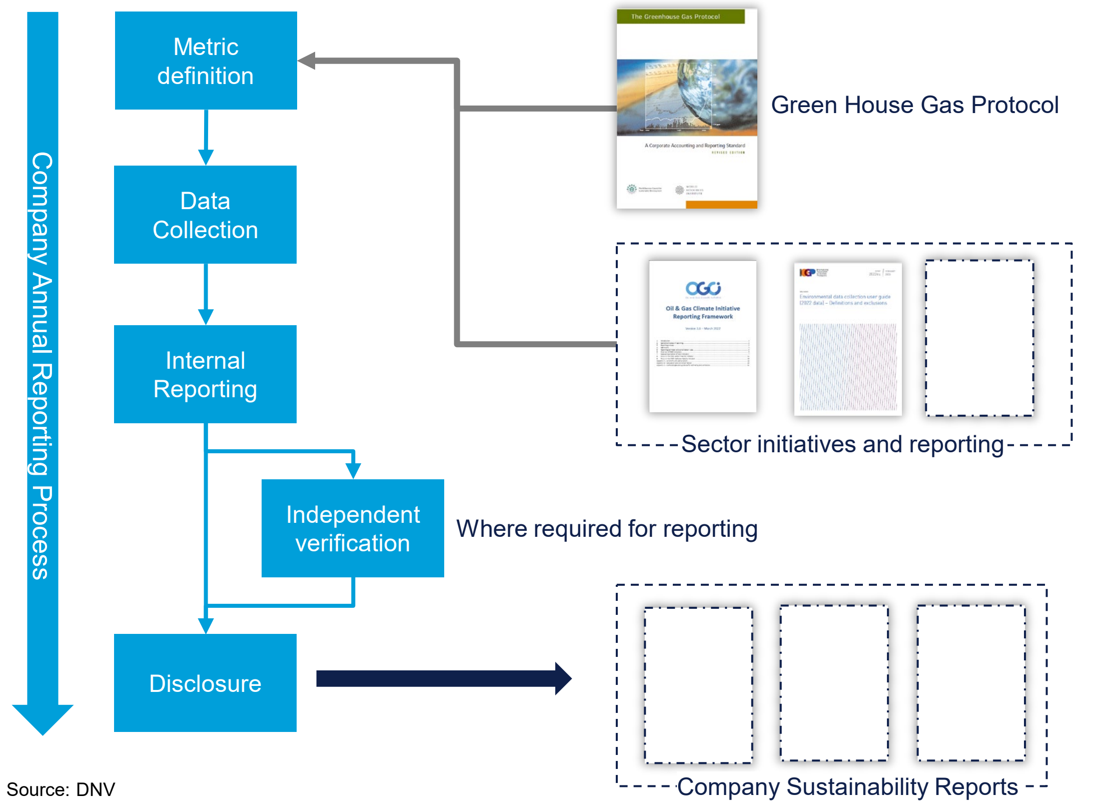
The sector is made up primarily of large International Oil Companies (IOC), National Oil Companies (NOC) and smaller Independent Oil Companies (Independent). Of these, IOCs publish the most detailed and comprehensive data driven by shareholder and wider stakeholder scrutiny. NOCs typically have less stakeholder pressure to disclose and so tend to only comply with applicable regulations. Independents generally have fewer resources to develop and report the data and so their reporting is much more inconsistent if they report at all.

Although most companies quote the Greenhouse Gas (GHG) Protocol as the basis for their reporting, they interpret the requirements differently in terms of boundaries, units and reporting basis (i.e. equity, operational control, financial control). Contracting terms (such as production sharing agreements) also impact the disclosure made.

Most producers only report Scope 1 (own emissions) and Scope 2 (from purchased energy). Scope 3 are not readily reported as these are more difficult to measure. Scope 3 associated with contracted services for production (categories 1 to 8) require engagement with suppliers and sharing of accurate information. Scope 3 emissions associated with getting the product to market and its use (categories 9 to 15) are generally reported by IOCs but sporadically by other operators. A large proportion of the companies reporting to shareholders, report GHG emissions data that has been independently verified.

The sector recognises that consistent reporting standards are needed, and efforts are being made to that end. Different programmes have been launched, by organisations such as the Oil & Gas Climate Initiative (OGCI), to drive consistency in reporting and establish targets. However, none of these programmes have yet fully penetrated the sector to the point of driving widespread consistent reporting. This means determining sector-wide performance is challenging and has wide levels of uncertainty.

For this study: DNV used publicly available reporting from 60 Oil & Gas companies from 2021. It worked to ensure the figures used were as consistent as possible resulting in a subset of results from 30 companies whilst retaining representation across all company types and geographical regions. Further information on the dataset is given later.



Source: DNV

3. Evaluation of possible GHG emissions alongside the value chain

3.2 GHG emissions from upstream onshore and offshore hydrocarbon production

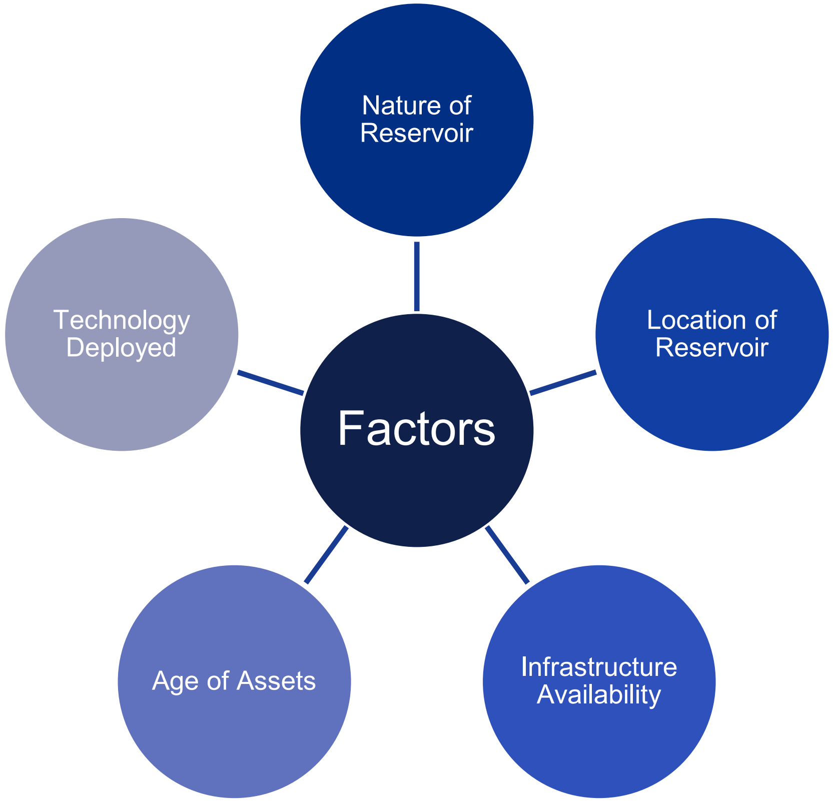
Upstream emissions vary by type of asset and geographical region as well as the technology used. Older assets tend to be less energy efficient and suffer more leaks. New assets benefit from low carbon power solutions, newer reservoirs and better operational controls.

Factors Impacting Emissions Intensity

There are a range of factors that affect the emissions associated with upstream oil & gas production. These have a significant impact on the emissions associated with each asset throughout its lifecycle. This means that company-level reporting is heavily impacted by the assets within the portfolio being considered.

- **Nature of the reservoir** – The pressure, associated fluids and associated solids have a significant impact on the operational emissions to lift the gas to surface then do initial separation ready for export. Older reservoirs tend to have more associated water and solids that take energy to separate, process and dispose of.
- **Location of the reservoir** – Production operations in remote or offshore locations tend to result in higher operational emissions as power generation (typically gas turbine driven) is needed for compression and life support. The growth of on and offshore wind generation at scale offers some assets opportunities for renewable energy sources to be deployed reducing emissions.
- **Infrastructure availability** – Connections to pipeline transmission or gas transportation mean more stable operations and tend to result in less venting or flaring.
- **Age of the asset** – Older facilities tend to incur more production upsets and be subject to more leaks than newer assets resulting in higher fugitive emissions and flaring. Reduced use of flanged connections, better condition monitoring and more resilient materials all contribute to reducing emissions. Increased use of reusable assets, such as Floating Production, Storage and Offtake (FPSO) vessels allow offshore assets to be more readily overhauled and upgraded.
- **Technology deployed** – Use of more efficient pump and compression equipment has the potential to significantly reduce operational emissions. Better reservoir management maintains ideal operating conditions for longer reducing the need for intervention.

The impact of some of these factors can be influenced by local regulation which may require emissions reduction, incentivise investment in assets, or encourage decommissioning.



Source: DNV

3. Evaluation of possible GHG emissions alongside the value chain

3.2 GHG emissions from upstream onshore and offshore hydrocarbon production

Publicly available data suggests that there is a broad range of emissions performance across the upstream production sector.

Performance

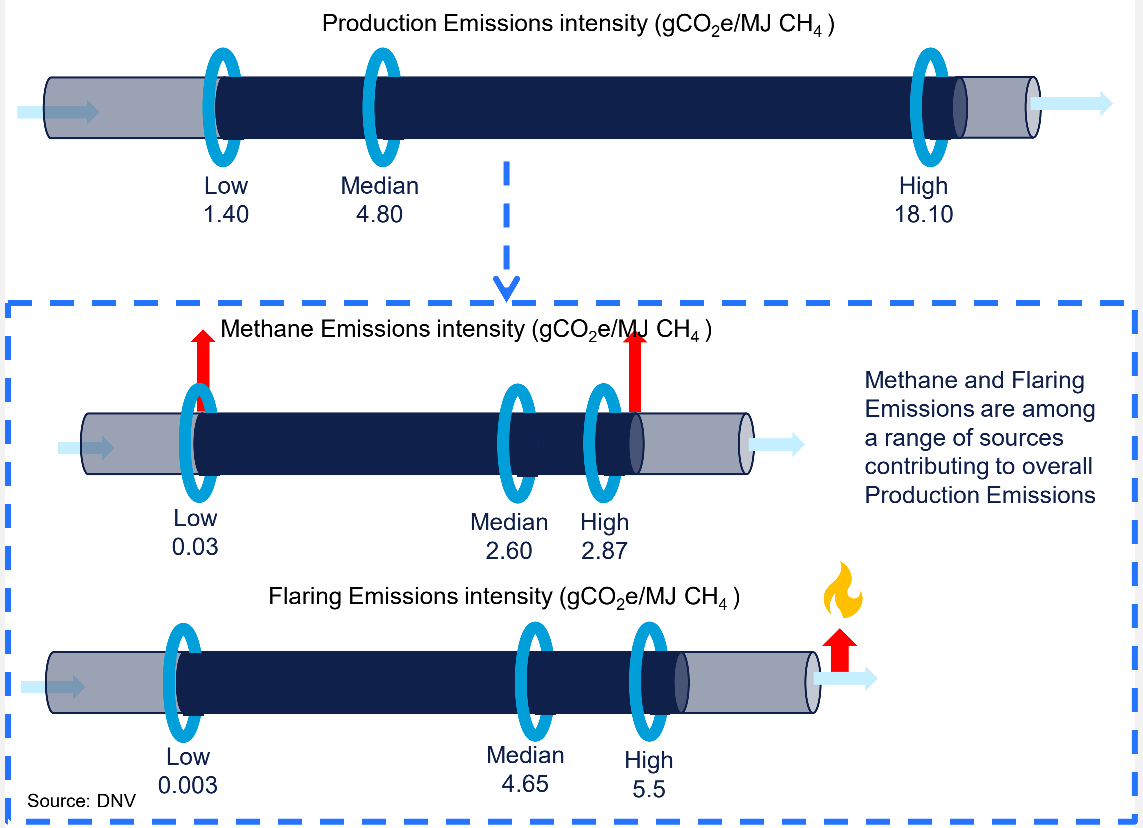
DNV used publicly available data from upstream operators and from other sources to determine the potential range of emissions.

Production Emissions intensity – Scope 1 & 2 emissions intensities are presented based on DNV's analysis of the public reporting. Excluding outliers, intensities typically are in the region 1.40 to 18.10 $gCO_2e/MJ\ CH_4$ (natural gas net or lower calorific value). Intensities below 1 $gCO_2e/MJ\ CH_4$ are possible but tend to be from assets with specific operating conditions. These intensities include flaring and methane emissions within Scope 1.

Contributing to the overall Scope 1 & 2 Production Emission Intensity (among other factors) are:

- **Methane Emissions Intensity –** These emissions are difficult to measure and are generally estimated by deducting measured output from measured inputs. There are wide variations in reported emissions with outliers showing emissions of below 0.1 up to 2.9 $gCO_2e/MJ\ CH_4$. However, there are significant gaps in reporting within the sector despite high-profile initiatives to disclose and reduce methane emissions.
- **Flaring Emissions –** Flaring is easier to monitor as flare systems can be fitted with metering. The sector has worked hard to reduce routine flaring (where associated gas is burned to prioritise oil production) but it does still happen where lack of infrastructure makes it difficult to get the gas to market. Emergency flaring results from unexpected upset conditions in the process system requiring rapid depressurisation for safety reasons. Again, there are significant differences in the range with outliers reporting above $gCO_2e/MJ\ CH_4$.

Scope 3 emissions have not been included in the report. As this report is looking at value chain emissions, emissions associated with end use of the gas (category 11) should be excluded. However it is generally not possible to extract category 11 emissions from the overall scope 3 reporting. This means that emissions are under estimated as they do not include contracted services. Depending upon the nature of the operations and the degree of outsourcing, scope 3 emissions from purchased goods and services (category 1) can be as much as twice the total scope 1 & 2 emissions. This suggests a significant underestimate of the total emissions intensity, but currently consistent with GHG Protocol requirements.



Source: DNV

3. Evaluation of possible GHG emissions alongside the value chain

3.2 GHG emissions from upstream onshore and offshore hydrocarbon production

The nature of upstream data suggests that gathering specific data about the actual production is important to have confidence in the emissions associated with products of the value chain.

Conclusions from upstream emissions

- There is a broad range of reported emissions performance. Inconsistent application of reporting standards means that it is not possible to present reliable figures across the sector.
- It is not possible to consistently isolate emissions associated with gas production. As a result, these numbers reflect overall hydrocarbon production which provides a conservative result as oil production tends to be more emissions intensive. However as oil, gas and condensate are generally produced together in varying degrees, using an overall figure is appropriate.
- Extreme outliers from the general emissions intensity ranges may be artifacts of specific factors some of which have little or no impact on emissions (e.g. production sharing agreements). As a result these have been excluded from the ranges below.
- International Oil Companies generally provide the most consistent, publicly available datasets, compliant with international standards (e.g. Green House Gas Protocol). National Oil Companies and Independents produce much more inconsistent publicly reported data, but may still have good quality data available for customers and partners.
- When building a blue hydrogen production facility, the specific emissions intensity associated with the methane source is critical to determining the overall emissions impact of the produced hydrogen.

Producing the figures:

DNV conducted a review of publicly available data sources for 2021 (the last year with most complete reported data). Data came largely from sustainability reports, annual reports and websites published by oil and gas producers. Around 60 companies covering all major producing regions were included.

It should be noted that 2021 was a year when the global economy began to rebound from the COVID pandemic and before the invasion of Ukraine. Thus, Russian sources are represented, playing a significant role in gas production in that year. The year was unusual compared with historical norms but was the last recent year where all regions contributed to an open market.

Low (best case)	Medium (median case)	High (worst case)
1.4	4.8	18.1
$gCO_2e/MJ.CH_4$	$gCO_2e/MJ.CH_4$	$gCO_2e/MJ.CH_4$

3. Evaluation of possible GHG emissions alongside the value chain

3.2 GHG emissions from gas transport

Emissions data for the different gas transport value chains remains a source of uncertainty.

Data Sources

DNV has analysed a wide selection of publicly available data alongside calculation from first-principles to assess the range of emissions intensity figures presented in literature. Several studies aiming to quantify the GHG emission impact from the natural gas value chain are available. However, all studies raise concerns over the accuracy and reliability of the figures produced due to a lack of transparent data and lack of accounting for methane emissions. In addition, a number of assumptions are applied in an effort to estimate emissions, such as different system boundaries, attempts to apply top-down and bottom-up principles to methane estimation, allocation of emissions to co-products, application of average emissions factors and assumed methane content of the natural gas.

The data reviewed are considered best available estimates, with US EPA Inventory of GHG Emissions and Sinks providing the most comprehensive dataset of emissions sources. The EPA publishes an annual report which produces estimates for US annual GHG emissions using emission factors. DNV has conducted a review of recent 2020 data and has applied this learning during assessment of the proposed range of emissions intensity figures, particularly in relation to gas pipeline transmission and storage.

Low, median and high emission intensity scenarios are taken from literature and adjusted from High Heating Value to Low Heating Value to allow comparison with the other sections of the blue hydrogen value chain.

Factors Impacting Midstream Emissions Intensity

There are a range of factors that influence the emissions associated with midstream gas transport and storage, with a large degree of asset specificity meaning that it is challenging to definitively define generalised upper and lower bounds for emissions intensity. The following hold significant influence over the midstream gas transport value chain emissions.

- **Geographical location** – The distance to energy markets is a crucial factor influencing the gas transport method, and governs the decision-making between the selection of long-distance pipelines or LNG. Longer distances result in higher emissions through additional compressor stations or longer voyages. Remote locations face challenges accessing low-carbon grid infrastructure, often burning fuel gas for on-site power generation at LNG facilities and compressor stations. Moreover, ambient conditions and challenging terrains can further impact energy requirements.
- **Process design** – Optimising pipeline design can minimize compressor station requirements and promote electrification. Similarly, optimizing liquefaction processes and shipping carriers in the LNG value chain can significantly lower energy consumption and emissions.
- **Methane** – Methane emissions have a substantial impact on emissions intensity. Long-distance pipeline infrastructure are particularly vulnerable to methane leakage and venting practises, contributing to a majority of the value chain emissions. However, accurately measuring and quantifying methane emissions remains challenging. Enhanced monitoring and reporting protocols, implementing leak detection technologies and adopting industry-wide best practices are crucial for mitigating methane emissions.
- **Ageing infrastructure** – Raises challenges in terms of increased leak paths and reduced efficiencies through reliance on older designs and outdated technologies. These factors contribute to a higher emissions intensity compared with modern best available techniques (BATs). Upgrading and modernizing infrastructure (e.g. electrification) can have a significant positive impact.

3. Evaluation of possible GHG emissions alongside the value chain

3.2 GHG emissions from gas transport – pipelines

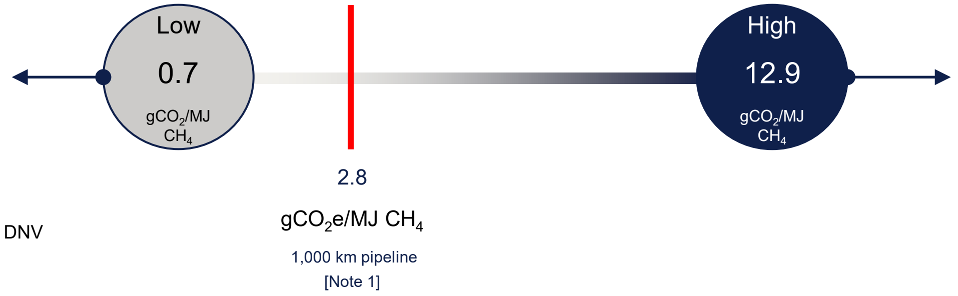
Publicly available data suggests that there is a broad range of emissions performance across the gas pipeline value chain.

Pipeline (transmission, storage, distribution)

Methane emissions throughout the natural gas transmission network account for the vast majority of GHG emissions. The low/high range presented from literature allocates the contribution to overall emissions for CH_4 and CO_2 as 78% and 22% respectively. However, recent US EPA data (2020) indicates the methane contribution could be as high as 95% for transmission and storage [Note 2]. CH_4 emissions arising from leakage from compressor stations (e.g. compressor seals), venting of pneumatic controllers and routine maintenance are significant sources of methane leakage from the system. Quantification of methane leaks is inherently difficult and therefore a large degree of uncertainty remains about the GHG data. Users of emissions data need to exercise caution as the range presents only indicative figures and the true GHG emissions intensity for a specific pipeline is influenced by multiple factors.

Overall Emissions Intensity – Scope 1 & 2 emissions intensity is typically in the region of 0.7 to 12.9 $gCO_2e/MJ\ CH_4$. Outliers of this range are possible, but have been excluded to provide a fair and representative range that reflects current best practise. As described previously, the uncertainty in methane emission quantification can result in large variability in reported intensity figures as it is the largest contributor.

- Methane Emissions Intensity – These emissions are difficult to measure and are generally estimated by deducting measured output from measured inputs. There are wide variations in reported emissions with outliers showing emissions of below 0.5 $gCO_2e/MJ\ CH_4$ and in excess of 9.5 $gCO_2e/MJ\ CH_4$.
- Combustion Emissions – The main source of combustion emissions is from the booster compressors that are fed from the pipeline gas. Typically, this intensity is in the region of 0.2 to 3.4 $gCO_2e/MJ\ CH_4$.



Source: DNV

[Note] An estimation for the gas shrinkage of long-distance transmission systems is typically 0.5% of the transferred gas volume per 100km, however transmission network design such as pipeline diameter and routing will have a large impact on this number.

3. Evaluation of possible GHG emissions alongside the value chain

3.2 GHG emissions from gas transport – pipeline transmission in gaseous form

A broad range in the emissions performance of gas transport via pipelines is evident due to several key factors.

Conclusions from gas transport via pipeline emissions

- It is evident that there exists a broad range in emissions performance and it is difficult to generalise the gas pipeline value chain. A number of factors influence the emissions intensity of a pipeline transmission and gas storage network, such as geographical distance and topography, pipeline design, maintenance regimes and compression station technology.
- Gas transport via pipeline generally has a lower emissions intensity compared to LNG, however the contribution of methane emissions to the overall GHG output is much higher. Low emissions intensity pipeline operation is achieved generally through electrification of compressor stations connected to low carbon grid infrastructure, however the low intensity figures presented here may be unrealistic as methane emissions could be underestimated. Equally, high emissions intensity transport may still be underestimating methane leakage across the system.
- Methane emissions are understood to contribute significantly to the emissions intensity of the network, however accurate quantification is difficult resulting in a high degree of uncertainty. Major leak paths such as at compressor stations, pneumatic devices and during routine maintenance are well-known sources.
- There is a general lack of good system-wide data on which to draw concrete conclusions for best and worst case emissions intensity, resulting in a number of assumptions applied in literature in an effort to estimate emissions with potential for real operation of gas transmission networks to be outside the range presented here. More detailed reporting and better measurement techniques should be applied to generate quality data for more detailed analysis.

Low (best case)	Medium (median case)	High (worst case)
0.7	5.4	12.9
$gCO_2e/MJ.CH_4$	$gCO_2e/MJ.CH_4$	$gCO_2e/MJ.CH_4$

3. Evaluation of possible GHG emissions alongside the value chain

3.2 GHG emissions from gas transport – LNG

Generally, the emissions intensity of the LNG value chain is higher than gas transport via pipelines. However, publicly available data suggests that there is a broad range of emissions performance.

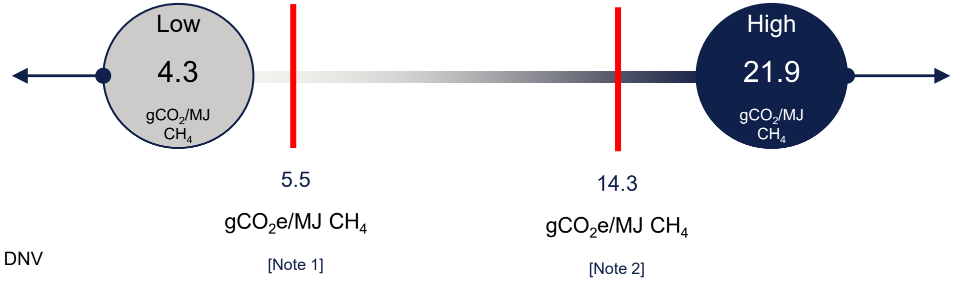
Liquefied Natural Gas (LNG)

There is a general lack of transparency around global GHG emissions performance data for LNG facilities, with quality and availability of data different from site-to-site, particularly with regards to methane emissions. However, generally the liquefaction stage will likely incur lower methane emissions due to the positioning of LNG facilities close to natural gas sources, requiring shorter distance pipelines. Storage and regasification facilities tend to have a higher methane load, but there is significant uncertainty in the data due to a lack of regular and reliable measurements.

Overall Emissions Intensity – Scope 1 & 2 emissions intensity is typically in the region of 4.3 to 21.9 $gCO_2e/MJ\ CH_4$ for the LNG value chain. Outliers of this range are possible but they have been excluded to provide a fair and representative range that outlines current best practise..

- Liquefaction – emission intensity is largely dependent on process technology, thermal efficiency (ambient temperature) and access to clean power. As such, there is a broad range in reported emissions of below 3 up to 11.3 $gCO_2e/MJ\ CH_4$. Methane is estimated to contribute 10-15% of total GHG emissions.
- Shipping– Typically, emissions intensity is in the region of 1 to 7.9 $gCO_2e/MJ\ CH_4$. Ship design and voyage duration are key factors, whilst methane venting and leakage is estimated to contribute a much smaller proportion of the overall emissions, circa 10%.
- Regasification –Typically, this intensity is in the region of 0.3 to 2.7 $gCO_2e/MJ\ CH_4$, with methane contribution in this section of the LNG value chain at its highest of 15-20%.

The scenarios presented in Notes 1 and 2 detail low and high emissions intensity LNG value chains. It is clear that factors such as deployed technology, geographical location, ambient conditions and ageing infrastructure play an important role in the overall efficiency of the LNG value chain.



Source: DNV

[Note 1] Lower emissions intensity LNG value chain example where liquefaction is conducted in a colder climate, increasing plant thermal efficiency, and electrification of key equipment such as refrigeration compressors, with power to the facility supplied by low emissions grid. Transport of LNG is via new membrane-type vessels, with a low BOG rate of 0.08% per day which is recovered. Shipping is fuelled by marine oil, with a voyage duration of 10 days. Regasification is completed via open rack vaporisers and methane leakage is minimised.

[Note 2] Higher emissions intensity LNG value chain example where liquefaction occurs in a hotter climate, reducing plant thermal efficiency. Optimised liquefaction processes and new technologies are not installed, relying on gas-driven compressors and on-site power generation from inlet natural gas feed, with frequent methane leaks due to ageing infrastructure. Transport of LNG is via moss-type vessels with a high BOG rate of 0.15% per day which is burnt for propulsion and a long voyage duration of 25 days. Regasification is completed with submerged combustion vaporisers resulting in a gas shrinkage of 1.5%.

3. Evaluation of possible GHG emissions alongside the value chain

3.2 GHG emissions from gas transport – Liquefied Natural Gas

A broad range in the emissions performance of gas transport via LNG is evident due to several key factors.

Conclusions from gas transport via LNG

- It is evident that a broad range in emissions performance exists and that it is difficult to generalise the LNG value chain. A number of factors influence the emissions intensity, such as deployed technology considering BAT, geographical location, ambient conditions governing thermal efficiency, ageing infrastructure and choice of LNG carrier vessel. A comparison of different low/high emissions intensity LNG value chains is provided on the previous slide.
- Owing to the additional processing steps, the LNG value chain generally experiences higher emissions intensity compared to gas transport via pipeline. Direct emissions of methane are far less throughout the LNG value chain, however combustion of natural gas primarily for gas-driven compressors and potentially electrical power results in higher CO2 emissions.
- There is a general lack of transparency and availability of emissions data associated with LNG facilities across the world, resulting in a high degree of uncertainty in the numbers presented here, particularly with regards to methane emissions.

Low (best case)	Medium (median case)	High (worst case)
4.3	9.6	21.9
$gCO_2e/MJ.CH_4$	$gCO_2e/MJ.CH_4$	$gCO_2e/MJ.CH_4$

3. Evaluation of possible GHG emissions alongside the value chain

3.3 GHG emissions from the production of blue hydrogen

There is no “typical” set of emissions from blue hydrogen production and we have produced a range of emissions by assessing SMR and ATR plant from across the world.

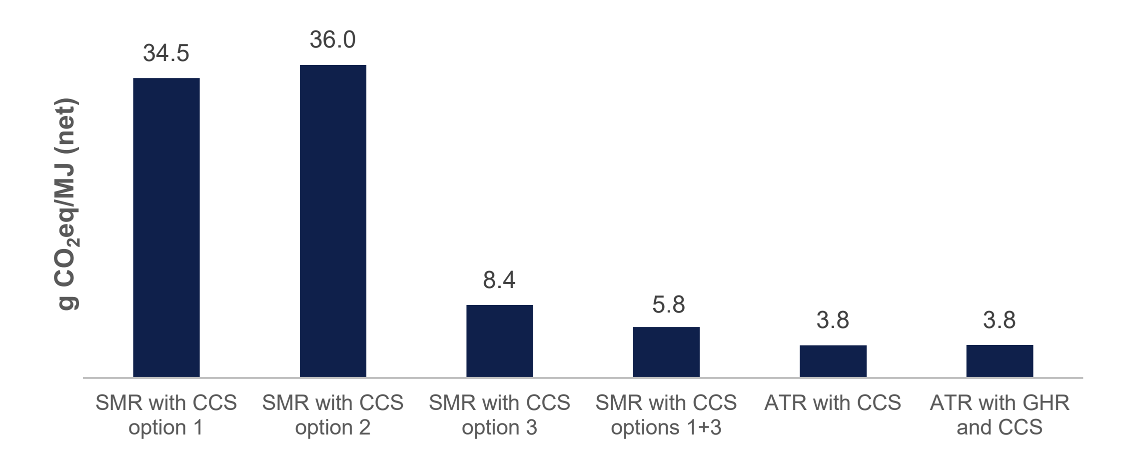
The analysis shows very clearly that the GHG emissions from SMR and ATR vary significantly depending upon the thoroughness of the carbon capture regime.

For SMR, if carbon capture is only carried out at the syngas stage (option 1 as described in section 2) or only at the tail gas stage (option 2), then little over 50% of the CO_2 emissions are captured. However, if CO_2 emissions from the flue gas (option 3) or the combined syngas and flue gas stages (options 1 and 3) then capture rates are over 90%.

For both ATR options, carbon capture rates are about 94%.

The hydrogen production routes that give the lowest carbon emissions are relatively expensive - the combined capture in SMR requires two separate capture plants whilst for ATR, an air separation unit is required to generate the oxygen required for the reformer.

The main message is that there is no single figure for the GHG emissions from hydrocarbon reforming plants – each SMR or ATR case needs to be examined individually noting the plant designs and operational methodologies. The range of CO_2 equivalent emissions expressed per unit hydrogen energy (net calorific value) is shown below.



Low (best case)
3.8
$gCO_2e/MJ.H_2$

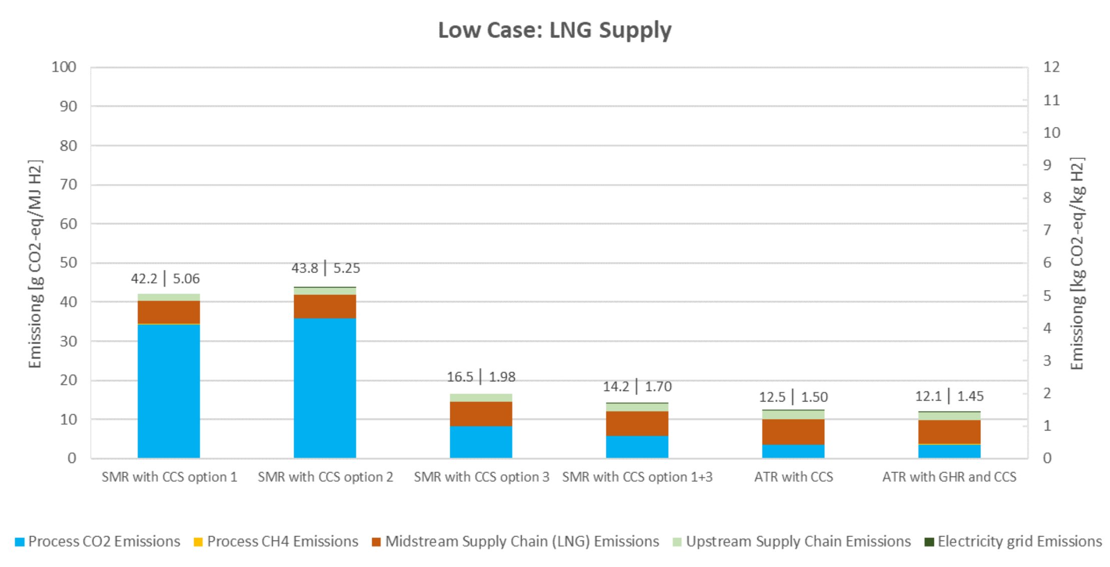
Medium (median case)
7.0
$gCO_2e/MJ.H_2$

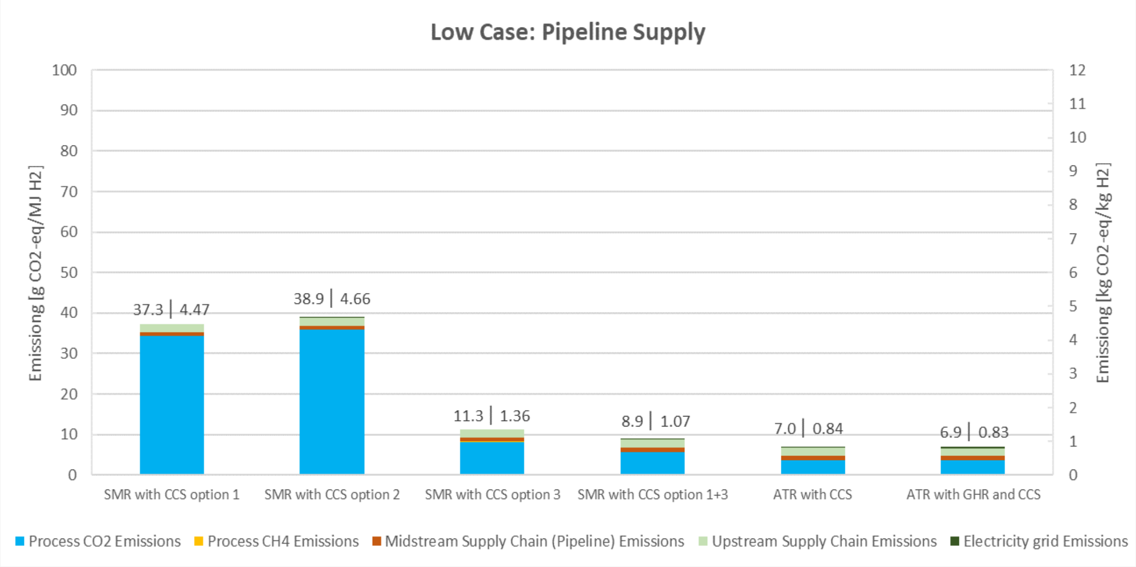
High (worst case)
35.0
$gCO_2e/MJ.H_2$

3. Evaluation of possible GHG emissions alongside the value chain

3.4 GHG Emissions – full value chain scenarios – Summary: Low supply chain emissions

There are combinations of upstream, transport (including LNG) and reforming technologies leading to a wide range of GHG intensities for hydrogen, as shown on the below graphs and the ones in the following two slides.



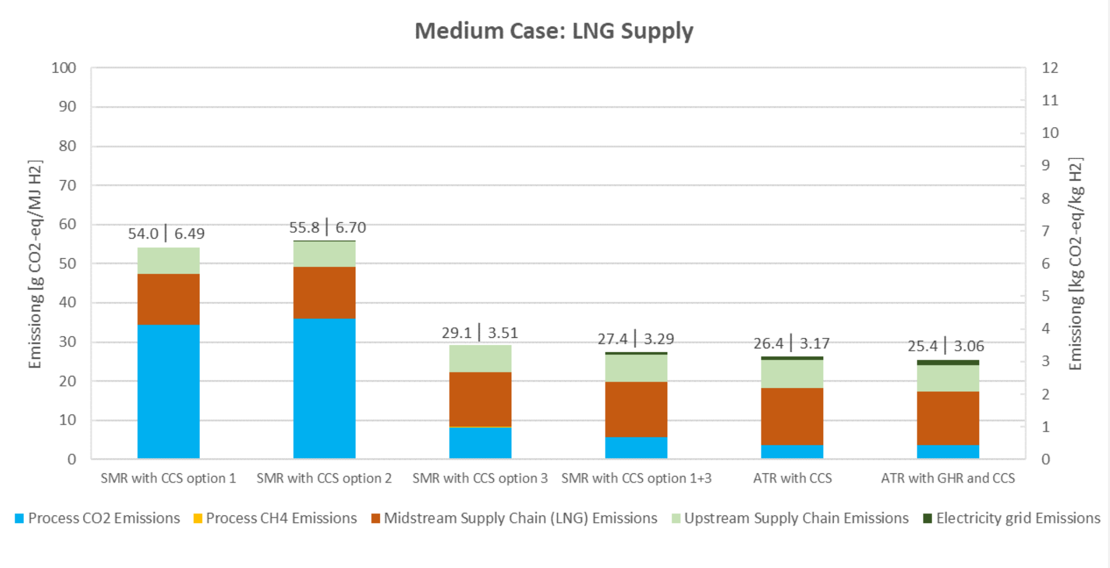


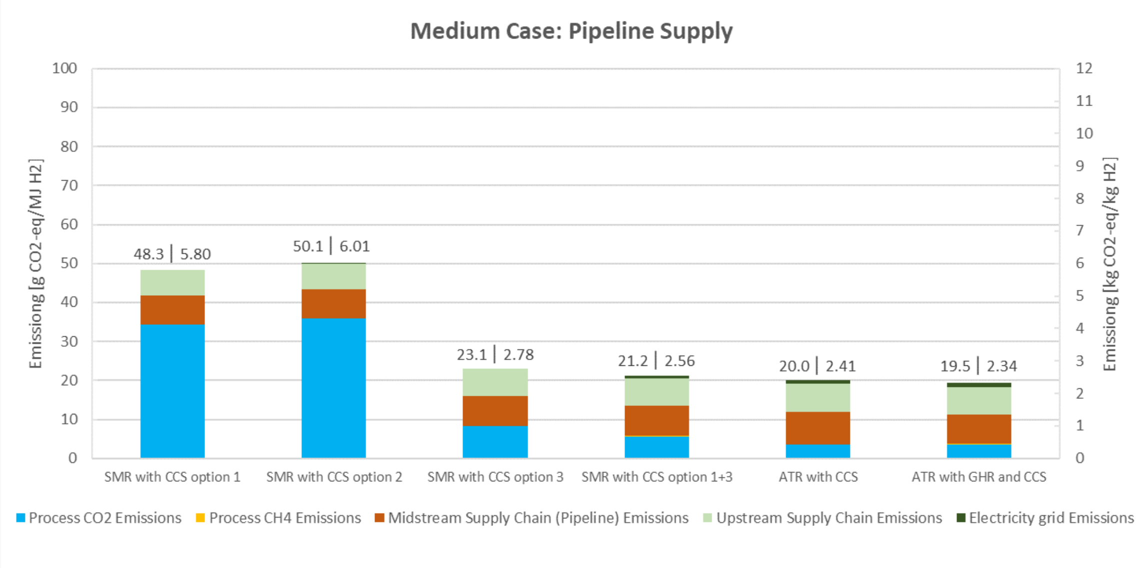
SMR with syngas CO_2 capture (Option 1)	SMR with tail gas CO_2 capture (Option 2)	SMR with flue gas CO_2 capture (Option 3)	SMR with combined syngas and flue gas CO_2 capture (Option 1+3)	Oxygen fired ATR with syngas high pressure CO_2 capture	Oxygen fired ATR with GHR and syngas high pressure CO2 capture

3. Evaluation of possible GHG emissions alongside the value chain

3.4 GHG Emissions – full value chain scenarios – Summary: Medium supply chain emissions

Even for the medium case, it is still possible to produce low-carbon hydrogen. However, the contribution from the medium LNG case becomes challenging.



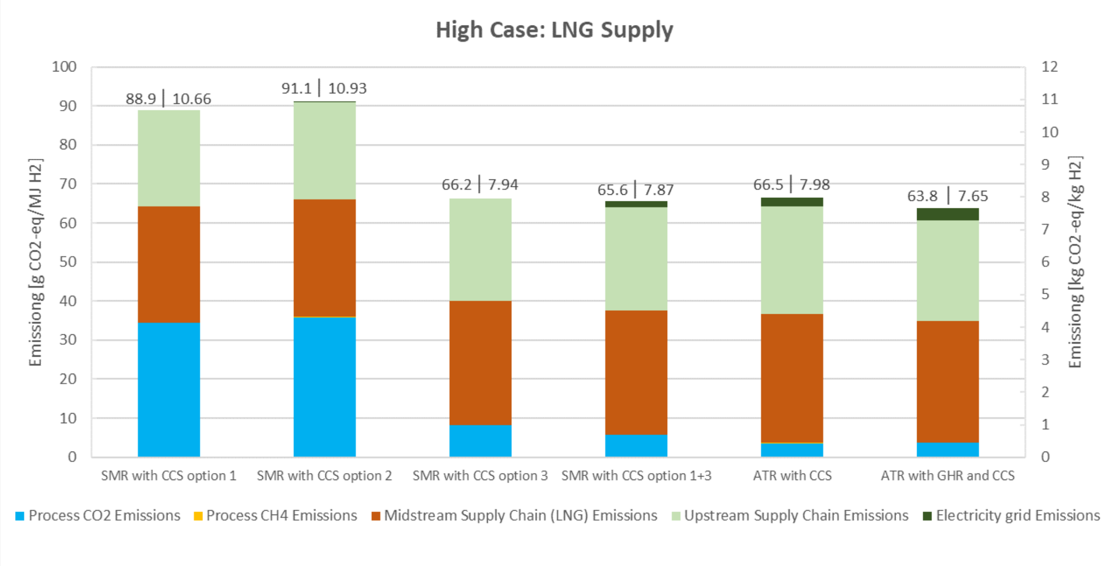


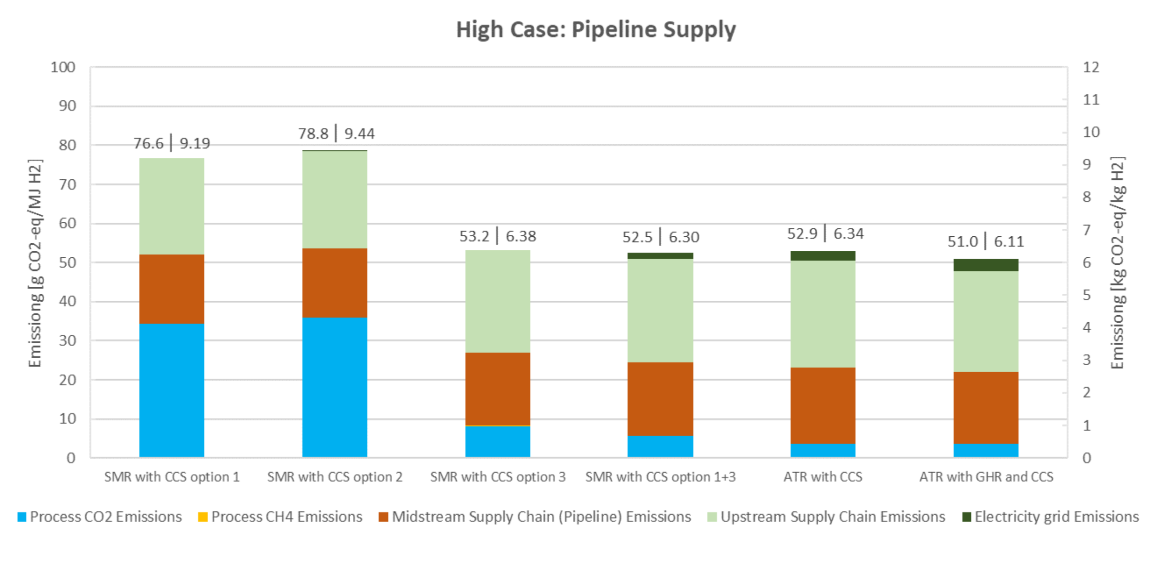
SMR with syngas CO_2 capture (Option 1)	SMR with tail gas CO_2 capture (Option 2)	SMR with flue gas CO_2 capture (Option 3)	SMR with combined syngas and flue gas CO_2 capture (Option 1+3)	Oxygen fired ATR with syngas high pressure CO_2 capture	Oxygen fired ATR with GHR and syngas high pressure CO2 capture

3. Evaluation of possible GHG emissions alongside the value chain

3.4 GHG Emissions – full value chain scenarios – Summary: High supply chain emissions

When supply chain emissions are high, it is only just possible to achieve reduced-carbon hydrogen. Low-carbon hydrogen is not achievable.





SMR with syngas CO_2 capture (Option 1)	SMR with tail gas CO_2 capture (Option 2)	SMR with flue gas CO_2 capture (Option 3)	SMR with combined syngas and flue gas CO_2 capture (Option 1+3)	Oxygen fired ATR with syngas high pressure CO_2 capture	Oxygen fired ATR with GHR and syngas high pressure CO2 capture

3. Evaluation of possible GHG emissions alongside the value chain

3.4 GHG Emissions – full value chain scenarios – Summary:

Production of blue hydrogen is strongly dependent on emissions throughout the supply chain. Low-carbon and even ultra-low carbon hydrogen production is possible but will require a case-by-case assessment.

		Threshold levels for Hydrogen Production†		
	Supply chain emissions	Reduced carbon hydrogen 50 g CO_2e/MJ H_2 (net) | 6 kg CO_2e/kg H_2	Low-carbon hydrogen 25 g CO_2e/MJ H_2 (net) | 3 kg CO_2e/kg H_2	Ultralow-carbon hydrogen 8.3 g CO_2e/MJ H_2 (net) | 1 kg CO_2e/kg H_2
High, Medium and Low results	**All at the low end of range** 0.83 to 5.25 kg CO_2e/kg H_2 | 6.9 to 43.8 g CO_2e/MJ H_2 (net)		Excluding SMR with option 1 or option 2 carbon capture	Only with hydrogen production using ATR
	All at the medium of range 2.34 to 6.70 kg CO_2e/kg H2 | 19.5 to 55.8 g CO_2e/MJ H2 (net)	Excludes LNG transport + with SMR with option 1 or option 2 carbon capture	Excludes LNG transport except when combined with ATR	Not possible
	All at the high end of range 6.11 to 10.93 kg CO_2e/kg H_2 | 51.0 to 91.1 g CO_2e/MJ H_2 (net)	Only ATR with Gas Heated Reformer and carbon capture	Not possible	Not possible

It is possible to achieve the emissions threshold with all options

Only some options can achieve the emissions threshold

No options can achieve the emissions threshold

The output of this study suggests that it is only at the low end of the emissions range, where upstream, midstream and production approaches are all delivering minimum GHG emissions, that the value chain comfortably meets the 50 gCO_2e/MJ H_2 criteria for reduced carbon blue hydrogen. All other tighter emissions thresholds require particular combinations of technologies and supply chain options to be able to meet the criteria. This indicates that the specific supply chain arrangements are key to demonstrating whether blue hydrogen production is sufficiently low carbon.

SMR with syngas CO_2 capture (Option 1)	SMR with tail gas CO_2 capture (Option 2)	SMR with flue gas CO_2 capture (Option 3)	SMR with combined syngas and flue gas CO_2 capture (Option 1+3)	Oxygen fired ATR with syngas high pressure CO_2 capture	Oxygen fired ATR with GHR and syngas high pressure CO2 capture

† From World Business Council for Sustainable Development (WBCSD)

4. Requirements for low-GHG emissions of blue hydrogen

Building confidence in hydrogen emissions intensity

The quantification of emissions intensity of blue hydrogen requires clear measurement and accounting standards in a number of sectors to ensure input data can be trusted. Specifics are important as a broad range of factors have a significant impact on emissions.

The nature of blue hydrogen is that it only represents a serious low-GHG energy route if it can be shown that it delivers low emissions. Confidence in the emissions intensity of blue hydrogen is critical. Details are important and need to be implemented/accepted globally

The report has shown that currently establishing that confidence is challenging. Key points are:

- There are broad ranges of emission intensities at each stage of the value chain. This is due to the different application of technologies, the length and nature of the methane supply chain and the route that the methane feedstock takes to the hydrogen production unit.
- The reported data has high levels of uncertainty due to inconsistent and missing reporting of emissions and due to a lack of operational experience in hydrogen production and carbon capture technology.
- The methods for calculating operational value chain emissions intensity are relatively straight forward and once key factors are defined then outputs can be presented transparently and consistently.

Therefore, to improve the confidence in reporting of blue hydrogen emissions, two things are required:

1. **Much better and consistent reporting of emissions intensities for each part of the value chain**. This requires agreement across a wide range of organisations in a broad range of sectors. DNV's suggestions are:
   - A standard for consistent reporting of emissions intensities for the upstream and midstream sectors. This could include a means for accurately quantifying emissions associated with natural gas production and include Scope 3 emissions from contracted services.
   - Third party verification of the reported figures consistent with the certification already conducted by many companies for their reported GHG emissions.
2. **Clear reporting of the methane supply route specific to the hydrogen produced.**
   - Where the methane comes from a range of sources, a consistent means for aggregating the emissions intensities is required so that the relative performance of different blue hydrogen sources can be evaluated. This could be in the form of upper and lower ranges and/or a median figure.
   - However, to do this will require regular review and update of the supply chain route and associated emissions. This may be achieved through industry level databases as long as input data is consistently measured and reported.

Incentives for transparent reporting are seen as coming from a number of areas:

- **Contractual requirement by blue hydrogen producers.** As a condition of supply, reported data will need to meet the required standard. This may impact the cost of blue hydrogen feedstock and make the output less competitive, a challenge the sector already faces.
- **Governmental regulation.** Regulation is becoming increasingly tight in the area of GHG emissions. As hydrogen demand increases for transportation and heating, planned national infrastructure will create a ready market that will require blue hydrogen sources. Regulators will respond to societal expectations that the hydrogen used has increasingly low-GHG-emission associated with it.

The focus here is on reporting the emissions rather than on how to reduce the emissions associated with the blue hydrogen value chain. DNV sees one as driving the other – better reporting will lead to lower emissions, particularly if the reporting starts to impact the marketability of methane feedstock and attracts increasing carbon taxes. The technology and operational controls needed to reduce value chain emissions exist, the pressure to apply them and return on that investment is what will deliver improved performance.

DNV

References

References

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[2] Balcombe, P., Anderson, K., Speirs, J., Brandon, N. and Hawkes, A., 2015. Methane and CO2 emissions from the natural gas supply chain: an evidence assessment. London: Sustainable Gas Institute, Imperial College London.

[3] Songhurst, B., 2018. LNG plant cost reduction 2014–18.

[4] Hafner, M. and Luciani, G., 2022. The Palgrave Handbook of International Energy Economics (p. 770). Springer Nature.

Appendix

Appendix A

Abbreviations

ASU - Air Separation Unit

ATR - Autothermal Reforming

BOG - Boil-off Gas

CCS - Carbon Capture and Storage

EPA - United States Environmental Protection Agency

EU - European Union

FPSO - Floating Production, Storage and Offtake vessel type

GHG - Greenhouse Gas

GHR - Gas Heated Reformer

GWP - Global Warming Potential

HHC - Heavy Hydrocarbons

HHV - Higher Heating Value

IOC - International Oil Company

IOGP - International Association of Oil & Gas Producers

IPCC - Intergovernmental Panel on Climate Change

IPHE - International Partnership for Hydrogen and Fuel Cells in the Economy

LHV - Lower Heating Value

LNG - Liquid Natural Gas

MJ - Mega Joule

NG - Natural Gas

NOC - National Oil Company

NOX - Nitrous Oxides

OGCI - Oil and Gas Climate Initiative

POX - Partial Oxidation

PSA - Pressure Swing Adsorption

SMR - Steam Methane Reforming

WBCSD - World Business Council For Sustainable Development

WGS - Water-gas shift

WRI - World Resources Institute

Source: DNV

Appendix B

Tabulated Results – Low Case

	Low Case, in unit of g CO2eq/MJ H2					
Supply chain emissions	Process CO2 Emissions	Process CH4 Emissions	Midstream Supply Chain (LNG, Pipeline) Emissions		Upstream Supply Chain Emissions	Electricity Grid Emissions
SMR with syngas CO2 Capture (Option 1)	34.37	0.05	5.86	0.95	1.91	0.00
SMR with syngas CO2 Capture (Option 2)	35.91	0.05	5.91	0.96	1.92	0.02
SMR with flue gas CO2 Capture (Option 3)	8.24	0.05	6.23	1.01	2.03	0.00
SMR with combined syngas and flue gas CO2 Capture (Option 1+3)	5.69	0.05	6.27	1.02	2.04	0.13
Oxygen fired ATR with syngas high pressure CO2 capture	3.61	0.05	6.51	1.06	2.12	0.19
Oxygen fired ATR with Gas Heated Reformer and syngas high pressure CO2 capture	3.64	0.05	6.12	1.00	1.99	0.26

	Low Case, in unit of kg CO2eq/kg H2					
Supply chain emissions	Process CO2 Emissions	Process CH4 Emissions	Midstream Supply Chain (LNG, Pipeline) Emissions		Upstream Supply Chain Emissions	Electricity Grid Emissions
SMR with syngas CO2 Capture (Option 1)	4.121	0.006	0.702	0.114	0.229	0.000
SMR with syngas CO2 Capture (Option 2)	4.306	0.006	0.708	0.115	0.231	0.002
SMR with flue gas CO2 Capture (Option 3)	0.988	0.006	0.747	0.122	0.243	0.000
SMR with combined syngas and flue gas CO2 Capture (Option 1+3)	0.683	0.006	0.752	0.122	0.245	0.015
Oxygen fired ATR with syngas high pressure CO2 capture	0.433	0.006	0.780	0.127	0.254	0.023
Oxygen fired ATR with Gas Heated Reformer and syngas high pressure CO2 capture	0.436	0.006	0.734	0.119	0.239	0.031

Appendix B

Tabulated Results – Medium Case

	Medium Case, in unit of g CO2-eq/MJ H2					
Supply chain emissions	Process CO2 Emissions	Process CH4 Emissions	Midstream Supply Chain (LNG, Pipeline) Emissions		Upstream Supply Chain Emissions	Electricity Grid Emissions
SMR with syngas CO2 Capture (Option 1)	34.37	0.05	13.07	7.35	6.54	0.00
SMR with syngas CO2 Capture (Option 2)	35.91	0.05	13.18	7.42	6.59	0.09
SMR with flue gas CO2 Capture (Option 3)	8.24	0.05	13.91	7.82	6.95	0.00
SMR with combined syngas and flue gas CO2 Capture (Option 1+3)	5.69	0.05	14.00	7.88	7.00	0.62
Oxygen fired ATR with syngas high pressure CO2 capture	3.61	0.05	14.52	8.17	7.26	0.93
Oxygen fired ATR with Gas Heated Reformer and syngas high pressure CO2 capture	3.64	0.05	13.66	7.68	6.83	1.26

	Medium Case, in unit of kg CO2-eq/kg H2					
Supply chain emissions	Process CO2 Emissions	Process CH4 Emissions	Midstream Supply Chain (LNG, Pipeline) Emissions		Upstream Supply Chain Emissions	Electricity Grid Emissions
SMR with syngas CO2 Capture (Option 1)	4.121	0.006	1.568	0.882	0.784	0.000
SMR with syngas CO2 Capture (Option 2)	4.306	0.006	1.581	0.889	0.790	0.011
SMR with flue gas CO2 Capture (Option 3)	0.988	0.006	1.668	0.938	0.834	0.000
SMR with combined syngas and flue gas CO2 Capture (Option 1+3)	0.683	0.006	1.679	0.944	0.839	0.074
Oxygen fired ATR with syngas high pressure CO2 capture	0.433	0.006	1.742	0.980	0.871	0.112
Oxygen fired ATR with Gas Heated Reformer and syngas high pressure CO2 capture	0.436	0.006	1.638	0.921	0.819	0.151

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Appendix B

Tabulated Results – High Case

	High Case, in unit of g CO_2-eq/MJ H_2					
Supply chain emissions	Process CO_2 Emissions	Process CH_4 Emissions	Midstream Supply Chain (LNG, Pipeline) Emissions		Upstream Supply Chain Emissions	Electricity Grid Emissions
SMR with syngas CO_2 Capture (Option 1)	34.37	0.05	29.82	17.57	24.65	0.00
SMR with syngas CO_2 Capture (Option 2)	35.91	0.05	30.07	17.72	24.86	0.23
SMR with flue gas CO_2 Capture (Option 3)	8.24	0.05	31.73	18.69	26.22	0.00
SMR with combined syngas and flue gas CO_2 Capture (Option 1+3)	5.69	0.05	31.94	18.81	26.40	1.56
Oxygen fired ATR with syngas high pressure CO_2 capture	3.61	0.05	33.13	19.52	27.38	2.35
Oxygen fired ATR with Gas Heated Reformer and syngas high pressure CO_2 capture	3.64	0.05	31.16	18.36	25.76	3.17

	High Case, in unit of kg CO_2-eq/kg H_2					
Supply chain emissions	Process CO_2 Emissions	Process CH_4 Emissions	Midstream Supply Chain (LNG, Pipeline) Emissions		Upstream Supply Chain Emissions	Electricity Grid Emissions
SMR with syngas CO_2 Capture (Option 1)	4.121	0.006	3.576	2.106	2.955	0.000
SMR with syngas CO_2 Capture (Option 2)	4.306	0.006	3.606	2.124	2.980	0.028
SMR with flue gas CO_2 Capture (Option 3)	0.988	0.006	3.804	2.241	3.144	0.000
SMR with combined syngas and flue gas CO_2 Capture (Option 1+3)	0.683	0.006	3.830	2.256	3.165	0.187
Oxygen fired ATR with syngas high pressure CO_2 capture	0.433	0.006	3.973	2.340	3.284	0.282
Oxygen fired ATR with Gas Heated Reformer and syngas high pressure CO_2 capture	0.436	0.006	3.737	2.201	3.088	0.380

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