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Research paper

# Lifetime greenhouse gas emissions from offshore hydrogen production

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ABSTRACT

With a limited global carbon budget, it is imperative that decarbonisation decisions are based on accurate, holistic accounts of all greenhouse gas (GHG) emissions produced to assess their validity. Here the upstream GHG emissions of potential UK offshore Green and Blue hydrogen production are compared to GHG emissions from hydrogen produced through electrolysis using UK national grid electricity and the 'business-as-usual' case of continuing to combust methane. Based on an operational life of 25 years and producing 0.5Mt$H_2$ per year for each hydrogen process, the results show that Blue hydrogen will emit between 200-262Mt$CO_2$e of GHG emissions depending on the carbon capture rates achieved (39%–90%), Green hydrogen produced, via electrolysis using 100% renewable electricity from offshore wind will emit 20Mt$CO_2$e, and hydrogen produced via electrolysis powered by the National Grid will emit between 103-168Mt$CO_2$e, depending of the success of its NetZero strategy. The 'business-as-usual' case of continuing to combust methane releases 250Mt$CO_2$e over the same lifetime. This study finds that Blue hydrogen at scale is not compatible with the Paris Agreement, reduces energy security and will require a substantial GHG emissions investment which excludes it from being a 'low carbon technology' and should not be considered for any decarbonisation strategies going forward.



## 1. Introduction

To mitigate the most catastrophic effects of climate change, governments globally are considering methods for decarbonising their energy systems. This is a massive undertaking, with systemic transformation required in every sector and facet of industry and society. As climate change is the direct result of the heating effect caused by the accumulation of anthropogenic greenhouse gas (GHG) emissions in the atmosphere, it is imperative that any decarbonisation strategy takes a thorough and holistic account of all GHG emissions released as a consequence of that strategy and compares these to the 'business-as-usual' GHG emissions to ensure that it will serve its primary purpose of rapidly reducing GHG emissions.

A key challenge is the very limited carbon budget available to decarbonise every aspect of society at every level; according to Buendia et al. (2019) for a 66% chance of keeping warming below 1.5 °C the remaining global carbon budget was just 320Gt$CO_2$e in 2020, or 1,070Gt$CO_2$e for 2 °C warming. Global anthropogenic GHG emissions are currently around 59 Gt$CO_2$e per year (United Nations Environmental Program, 2021) leaving a total global carbon budget of ∼200Gt$CO_2$e for 1.5 °C and ∼950Gt$CO_2$e for 2.0 °C; giving humanity around 3 years (1.5 °C scenario) and 16 years (2.0 °C scenario) of remaining budget.

The global energy sector, which relies heavily on fossil fuels, produces 73% of all global GHG emissions annually (Our World in Data, 2020) and therefore drastic reduction strategies must be put in place within this sector quickly. However, the carbon investment required to systemically decarbonise all energy systems globally, as well as satisfy increasing energy demand from developing economies must be very carefully considered with true and accurate GHG accounting, otherwise the risk is that one high emitting technology will be replaced with a different, but nonetheless high emitting technology, thereby wasting the remaining carbon budget.

Whilst many technologies are now commercially available to produce electricity at scale with zero or low operational emissions, there are some very large challenges in decarbonising sectors such as heavy industry (including steel and cement making), transport and domestic heating that currently rely almost entirely on fossil fuels. Hydrogen is an alternative fuel source that may address these challenges as it can be used as a gas fuel, either for heat or electricity generation, or in fuel cells and can also be used as a medium for energy storage (IRENA, 2019).

There are many different colours of hydrogen; and most relate to the feedstock and/or process of production. In the UK, developing a thriving hydrogen sector is a key 'plank' in the UK's

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2352-4847/

**Abbreviations**

| | |
|---|---|
| ATR | Autothermal Reforming |
| BEIS | Department for Business, Energy & Industrial Strategy |
| CC | Carbon Capture |
| CCS | Carbon Capture and Storage |
| $CH_4$ | Methane |
| $CO_2$ | Carbon Dioxide |
| CNS | Central North Sea |
| EEMS | Environmental and Emissions Monitoring System |
| GHG | Greenhouse Gas |
| GWP | Global Warming Potential |
| $H_2$ | Hydrogen |
| HC | Hydrocarbon |
| LCA | Life-Cycle Assessment |
| OGA | Oil & Gas Authority |
| OGI | Oil and Gas Industry |
| SRM | Steam Reformation |
| NAEI | National Atmospheric Inventory |
| NSTA | North Sea Transition Authority |
| P&A | Plug and Abandon |
| ROVs | Remotely Controlled Vehicles |

government's plan to 'build back better' with a 'cleaner, greener energy system' and they have ambitious plans for continuous hydrogen production output rate of 5GW per year by 2030 (Depatrment for energy security and Net Zero, 2021) made up of 50% Blue and 50% Green hydrogen.

In the production of Blue hydrogen, direct and indirect GHG emissions are produced at each stage of the production process; from the extraction, production, compression and transport of methane from oil and gas industry (OGI) assets, the steam reformation (SRM) or autothermal reforming (ATR), processing $CO_2$ exhaust, from the electricity needed to run both the SRM or ATR process and carbon capture (CC) operation/s, from upstream fugitive methane gas, and from energy that is required to compress, pump, transport and store the captured $CO_2$ and inject it into a depleted reservoir. Furthermore, the final product (the hydrogen) is also required to be transported to the end user and a variety of different methods have been discussed by Department for Business Energy & Industrial Strategy (BEIS) (2021) including transport over existing pipelines, with or without a methane carrier gas, and transport via ship (which are currently fuelled by marine diesel). Hydrogen also requires cooling and compression during transport which also has an energy input and associated GHG emissions. The UK's Blue hydrogen production is envisioned by various OGI operators such as Shell and BP to be an extension of the North Sea hydrocarbon (HC) industry whereby methane ($CH_4$) from mature gas fields is transported onshore, used as feedstock in the $H_2$ production plant with the resulting carbon emissions captured, compressed and transported offshore to be injected into depleted oil and gas reservoirs in the subsurface in the North Sea (refer to Fig. 1).

The volume of $CO_2$ emissions captured in the production of Blue hydrogen depends on how and where the $CO_2$ is captured and what happens to it once it is captured. Significantly CCS cannot be employed to capture fugitive emissions, but these must be accounted for to complete a holistic analysis of the total GHG emissions footprint.

UK plans for Green $H_2$ production involve building a series of offshore wind turbines to produce renewable electricity to power an electrolyser to split water into hydrogen and oxygen. GHG emissions will be produced during the construction and commissioning stage, including manufacturing of wind turbines, the $H_2$ production facility, transport via pipeline for the $H_2$ and electricity cables for transporting excess electricity onshore as illustrated in Fig. 2. No exhaust or process emissions will be produced through the production of electricity or $H_2$ and any emissions produced after the construction and commissioning stage will be due to maintenance and monitoring of the turbines and $H_2$ production facility and will be very low compared to construction and commissioning emissions.

Globally, other governments and industry are starting to invest in various hydrogen production schemes in Europe, Asia, Australia, China and the USA. Both the Netherlands (NortH2) and Germany (AquaVentus) plan to produce 1Mt of offshore hydrogen from wind powered electrolysis which will be transported to the mainland via pipeline. The NortH2 project has been given 'major project status' which means that it will be fast tracked through approvals, illustrating the high level of governmental support (Depatrment for energy security and Net Zero, 2021). However, very little public knowledge exists in regards to the GHG emissions produced from each of these schemes, and as such it is unclear how these decisions are being made. It is crucial that each scheme be quantified in terms of the GHG emissions it will produce, and that these accounts are holistic - not only to allow for public scrutiny but because this is the primary purpose of transitioning away from fossil fuels; to decarbonising society.

The aim of this study, therefore, was to model the total upstream lifetime GHG emissions of the UK governments' hydrogen strategy and compare the results to producing hydrogen via electrolysis using electricity produced via the UK's national grid and the 'business-as-usual' scenario of continuing to combust methane. The reason to only include upstream GHG emissions is that there is a severe lack of data for downstream emissions. To allow further comparisons, Grey hydrogen (hydrogen produced from methane feedstock but without CCS) was also included in the analysis.

## 2. Literature review

The literature review summaries the technical aspects of the different hydrogen production processes, and where the likely GHG emissions will be sourced from. This section also discusses the literature availability for key technical questions including the upstream methane leakage rates (fugitive methane) in the UK North Sea and theoretical and 'real world' Carbon Capture and Storage (CCS) rates because these are crucial in determining the life-time carbon footprint of blue hydrogen production methods, are highly controversial and are not well defined currently.

### *2.1. Blue hydrogen and carbon capture and storage (CCS)*

As discussed in the introduction, are two methods currently for producing Blue hydrogen; SMR and ATR. In an SMR plant (refer to Fig. 3), there are two sources of direct carbon dioxide: firstly, from the oxidation of the carbon atoms present in the feedstock during reforming (around 60% of the hydrogen plant's exhaust emissions) and secondly from the combustion occurring in the reformer furnace (around 40% of the hydrogen plant's exhaust emissions), therefore, an SMR plant would need two separate carbon capture plants, pre- and post-combustion (Antonini et al., 2020).

In an ATR plant (Fig. 3), the only source of direct $CO_2$ emissions is the combustion of the gas in the fired heater, therefore only a post-combustion capture plant is required (Antonini et al., 2020).

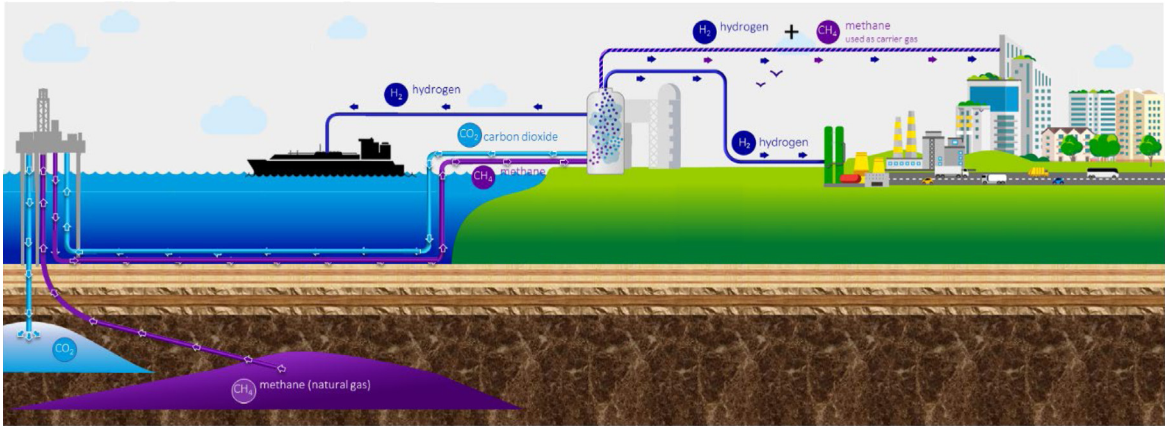


**Fig. 1.** Schematic diagram of Blue $H_2$ production. $CH_4$ is the feedstock for $H_2$ production and is extracted from OGI assets, extending the field life of those assets. The $CH_4$ is then transported onshore to the $H_2$ plant, where $H_2$ is produced. The resulting $CO_2$ emissions are captured, transported offshore and injected into a depleted oil or gas reservoir for long term storage. $H_2$ is compressed and transported downstream via pipeline, potentially with methane being used as a carrier gas. The UK plans include transporting the hydrogen by ship to markets further afield. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)
*Source:* Adapted from BP (2021).

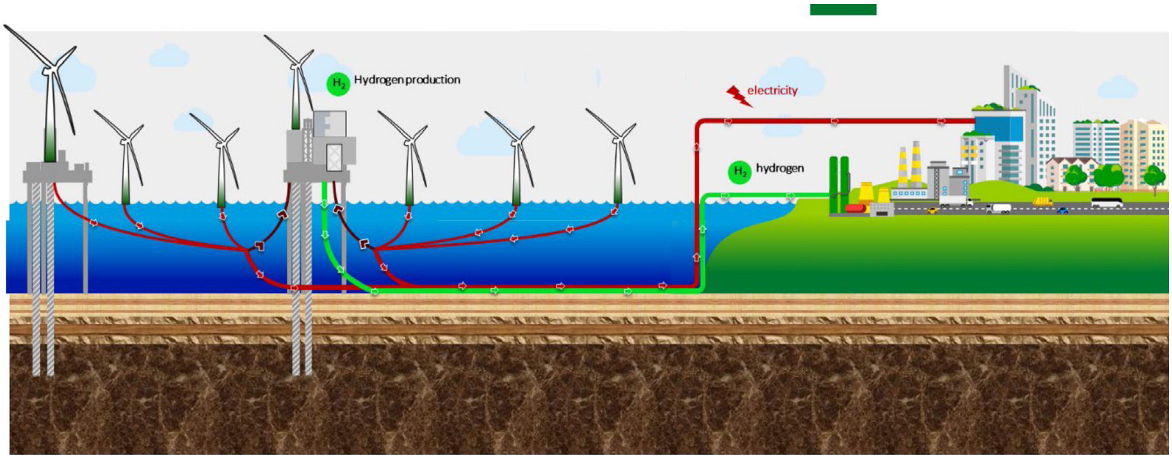


**Fig. 2.** Green hydrogen production offshore UK. Electricity is produced via offshore wind turbines, which is then used to power the electrolysers which will convert water to hydrogen. The hydrogen is transported onshore via pipeline to the downstream customer. If excess electricity is produced, this can also be transported onshore via cable. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)
*Source:* Diagram adapted from BP (2021).

Many actors believe that high emitting technologies such as Grey hydrogen become near-zero carbon or low carbon with the addition of Carbon Capture and Storage (CCS) as they believe that GHG emissions to air can be reduced and believe capture rates of more than 95% can be achieved (Department for Business Energy & Industrial Strategy (BEIS), 2021; United Nations Economic Commission for Europe (UNECE), 2022; Moseman and Herzog, 2021). In reality, rates of carbon capture achieved under real world conditions are rarely reported with flagship CCS projects achieving much lower capture rates than lab-based studies and expectations (Longden et al., 2022). Two such examples are the Petra Nova CCS project which captured just 1/3 of all $CO_2$ emissions and the Boundary Dam project having a capture rate of just 31%. According to Global Witness (2022) Shell's Quest CCS system operating at its Alberta hydrogen plant where hydrogen is made from fossil fuels has produced 12.5 $MtCO_2e$ and captured 4.8 $MtCO_2e$, this is a capture rate of 39%.

Most carbon captured in the US is used for enhanced oil recovery (EOR) and underground retention can vary between different EOR projects and over time (IRENA, 2019) with published figures of retention between 28%–90% of captured $CO_2$, no long-term retention figures for pure CCS operations are currently publicly available.

### 2.2. Upstream $Ch_4$ leakages, losses, fugitives and venting and flaring

A detailed study of potential UK fugitive methane emissions was undertaken as very little previous work has been conducted and this knowledge gap contributes significantly to the uncertainty of current calculation methods. Furthermore, because methane is such a potent GHG (Buendia et al., 2019) a small volume can cause significant warming potential.

Howarth and Jacobson (2021) used estimates from 20 different studies in 10 different gas fields, plus an estimate for transport and storage in their analysis and found an average for methane emissions, (also known as the methane intensity) of 3.5% of consumption for fugitives, leakages, venting and flaring in the USA. Unfortunately, in the UK there is a significant lack of publicly available data and no reliable industry data that quantifies these emissions from the UK North Sea.

Critics of the Howarth and Jacobson (2021) article have argued that the same emissions value cannot be applied to other oil and

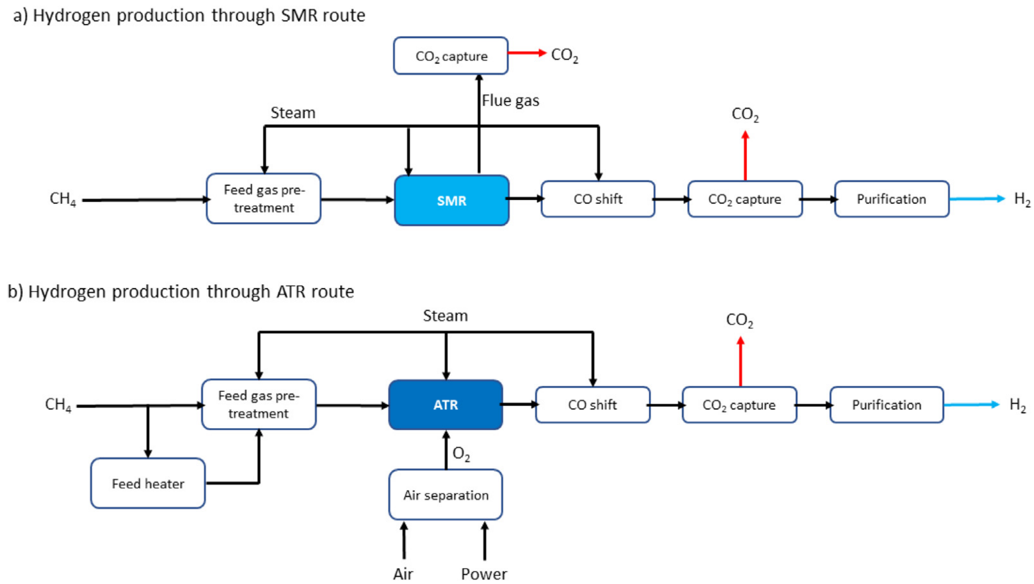


**Fig. 3.** System diagrams of the Blue hydrogen production, (a) is the SMR process (b) is the ATR process. Feedstock (methane) comes from OGI offshore assets as well as this being the location for long term storage of the captured carbon dioxide emissions. (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)
*Source:* Adapted from Liu (2021).

gas producing regions, especially in the EU. A blog by Gardarsdottir and Nekså (2021) questioned the assumptions in Howarth and Jacobson (2021) and argued that UK North Sea emissions are more than 100 times lower than US methane emissions. They use two studies as proof of this. The first study they quote gave a value of 0.03% for methane emissions intensity as an equivalent for the Norwegian sector. This value comes from the Annual Reports from Norwegian Oil and Gas major, Equinor, is not peer reviewed and is hidden within their large amounts of 'sustainability' reports so is very difficult to analyse how they calculated or obtained this figure.

The second figure they quote for methane intensity is 0.23% which they claim to be from a global study. The study they quote is by Riddick et al. (2019), an investigation into ambient methane around oil and gas platforms in the UK Central North Sea during normal operations. Only eight UK central North Sea oil and gas platforms were part of the study, four gas platforms and four oil platforms, thereby only representing a small fraction of total North Sea wells (UK Central North Sea (CNS) wells currently number around 2000), this is clearly not a global study. Furthermore, the Riddick et al. (2019) study is not a like for like comparison with the Howarth and Jacobson (2021) study as it does not include items such as flaring, venting and others such as subsurface gas emplaced in drilling fluids.

Whilst the Riddick et al. (2019) study is an important explanation of so far 'missed' methane emissions and should encourage further investigation, a number of assumptions were made within the study that could indicate even higher levels of methane emissions.

1. The study assumed the methane was coming from the working deck but could in fact be released in a number of alternative locations such as the flare stack, wellbore, seafloor or risers.
2. They assume uniform vertical mixing and a constant wind speed – both of which are highly unlikely in the real world.
3. They assume the fluids are at ambient air temperature, however as the fluids are being extracted from depths in the subsurface, they could be significantly warmer. According to Fleming (1996) the Central North Sea (CNS) range in temperature gradients is 20-51 °C km$^{-1}$ depth, with an average temperature gradient of just over 36 °C km$^{-1}$ depth and the average summer air temperature of between 18-22.6°. One of the deepest wells drilled in the North Sea is 8583 m and by applying the geothermal gradient of 36 °C (although this is not specific to the area) would mean fluid temperatures of $8.583 \times 36 = 309$ °C (Eck-Olsen et al., 2012). However, new research shows this temperature gradient could be even higher, estimating it to be 6 °C warmer than current estimates (Sarkar and Huuse, 2022).

According to Riddick et al. (2019) several activities are explicitly identified by BEIS in the National Atmospheric Inventory (NAEI) as sources of emissions, but leakage during normal operations is not. Previously published emissions from the platforms in the Northeast Atlantic Region are reported to be almost entirely due to flaring (83%) and offshore oil loading (17%), with reported emissions generated using emission factors (Brown et al., 2017; Department for Business Energy & Industrial Strategy (BEIS), 2019).

The Environmental and Emissions Monitoring System (EEMS) database, the system used for OGI to declare emissions, do not expect the OGI to monitor or measure emissions directly but provide methods for calculating them based on activity data such as fuel consumption and emissions factors. Without direct measurement, operators can remain unaware of emissions that occur during normal operations (Nara et al., 2014) and this is probably the case in the North Sea.

The platform methane loss figure from Riddick et al. (2019) of 0.23% of production are in addition to the other sources, as platform losses measured by Riddick et al. (2019) during normal production and are not included in the overall methane loss calculations methods currently employed by the OGI. Until now these losses have been overlooked.

Another source of overlooked emissions includes emissions from leakages around bore holes of wells. A recent study by Böttner et al. (2020) using a combination of existing regional industrial seismic and hydroacoustic data showed that of 43 plugged and abandoned wells investigated, 28 released gas from the wells into the water column. They suggest that gas released from decommissioned hydrocarbon wells is a major source of methane in the North Sea at 0.9–3.7kt/yr of $CH_4$ for 1,792 wells in the UK sector of the (CNS). According to the latest report from the IPCC (IPCC, 2022) the global warming potential (GWP) for methane is 82 over a 20-year period, so up to 307,100t$CO_2$e is probably being released each year.

Methane leakages can be compounded by geotechnical fracturing around the wellbore and gas can escape through a number of pathways including between the casing and cement, between the cement plug and casing, through the cement pore space (as a result of cement degradation), through casings as a result of erosion, through fractures in the cement and between the cement and sediment (Vielstädte et al., 2015).

Further 'missed' emissions are described in the Leifer and Judd (2015), an investigation into continuing methane emissions from well 22/4b. This well had a blowout that occurred in 1990 and in 2011 the investigation found methane was still leaking. Seabed bubble flux estimates indicated methane emissions rates of 90$Ls^{-1}$. No further monitoring or estimates of release rates have since been undertaken, we do not know if methane is still being released.

According to Leifer and Judd (2015) a strong thermocline that persists for half the year in the North Sea acts as an effective barrier to upward migration of methane, and a large percent is advected away from the source site. During autumn and winter there is no thermocline present and as such it is expected that methane emissions will reach the atmosphere by the normal air:sea gas exchange process and will show a significant increase in atmospheric methane emissions, but no known further studies have looked at this at all to date. Nauw et al. (2015) state that the North Sea hydrodynamic systems are key to redistribution of methane released at any site in the subsea. During the un-stratification part of the season when no thermocline is present, sea:air transmission of methane will be almost instantaneous but if methane remains in the water column it has the potential to add significantly to ocean acidification with long lasting and cumulative impacts on sea life and the marine environment.

Fugitive emissions from offshore OG platforms are much harder to measure than onshore installations as methane released at the seabed or in the water column will not necessarily reach the air and may be transported to other areas by currents and tides or be absorbed by the water column and measurements around the platform will almost certainly be underestimated due to this problem (Nauw et al., 2015).

Venting and flaring is a common practise in the OGI and is the process of releasing unwanted gases direct to the air. Venting is when the methane is released directly to the air and flaring is used to convert the methane to carbon dioxide via combustion and thereby reduce the short-term impact of global warming.

According to Mackay et al. (2021) regulations influence methane emission rates; an example from Canada showed that when regulations to eliminate all venting came into force, methane emissions reduced by $\frac{3}{4}$. In the UK, strong regulations mean that progress has been made to reduce cold venting and flaring, but large volumes are still being released. For example, in the UK North Sea in 2019 there were 128 hydrocarbon (HC) releases, up from 101 in 2018, this figure included three major releases (Health & Safety Executive (HSE), 2022). Published data includes some release rates and a calculation of total mass of HCs released, but over 50% of the individual releases are not include this data.

In the UK venting and flaring data is reported every year to the North Sea Transition Authority (NSTA), formerly the Oil & Gas Authority (OGA). The latest data for 2019 (Gvakharia et al., 2017) shows 42bcf of methane was flared and 773mmscf of methane was vented, down from 1,106 mmsf in 2018. This reduction is due to changes in legislation and the drive to reduce emissions from North Sea operations. This data assumes a combustion efficiency of 80% which is derived from lab-based studies (Gvakharia et al., 2017). The real-world environment does not behave in the same way as a lab environment and various inputs such as flow rate, aeration and importantly wind speed will impact the combustion efficiency. Very few studies have investigated this in the real world, and to our knowledge no UK North Sea studies have been published.

Gvakharia et al. (2017) point to a Canadian study that investigated two flare sites and observed combustion efficiency of 68% ± 7%. This discrepancy between lab-based data and real-world data is worrying and potentially ignores large emissions and is very much dependent on a number of factors, including the type of hydrocarbon as well as the age and maintenance record of field infrastructure, as other studies have also found (Riddick et al., 2019; Böttner et al., 2020; Mackay et al., 2021).

The two important studies described here by Riddick et al. (2019) and Böttner et al. (2020) show significant sources of methane emissions that are not currently included in emissions estimates or inventories. A recent study showed that methane emissions are underreported globally by 57–76Mt$CH_4$, in all sectors including the OGI (Mooney et al., 2021). This gap is significant and should be urgently closed. One method for obtaining more accurate methane emissions estimates is through the use of satellite imagery. Lauvaux et al. (2021) analysed images captured by the TROPOspheric Monitoring Instrument (TROPOMI) between 2019 and 2020 and found sporadic releases of large amounts of methane during maintenance operations and equipment failure that are not accounted for in any current inventory estimates. They found that the total contribution of ∼8 Mt$CH_4$, or 8%–12% of global methane emissions from OGI methane upstream production emissions. Existing satellites do not provide measurements over equatorial regions, northern areas and significantly, offshore operations (IEA, 2021) and therefore similar monitoring of UK offshore facilities is not currently possible. According to Ehret et al. (2021) top-down studies of methane leaks from OGI facilitates by recurrent Sentienel-2 satellite imagery revealed systematic under-estimation of $CH_4$ in national inventories and some research collaborations are beginning to address this knowledge gap in the UK North Sea. TotalEnergies for example have been working with GHGSat to develop imaging technology to monitor potential methane leak occurrences at offshore facilities. This project has had some success but is primarily focused on the TotalEnergies facilities and is not a basin wide study (TotalEnergies, 2021). Another research project that aims to demonstrate the ability to measure and monitor methane emissions started in July of 2021 as a collaboration between GHGSat, Chevron, Shell and TotalEnergies and aims to monitor 18 sites at offshore locations including the North Sea and Gulf of Mexico over a 12-month period (GHGSat, 2021).

Although this is positive news towards better potential leakage and fugitive monitoring, the challenge still remains that any leakages or fugitives subsea will not be picked up by satellites as water does not allow for the penetration of infrared into the water column, effectively making subsea releases invisible to satellites.

This indicates that the established methods for calculating methane emissions from offshore sources is currently not capturing all methane emissions and there is no obvious reason otherwise for the emissions being so much lower, even in areas under the same regulations regime and thereby subjected to the same regulations on venting and flaring. Many authors (Vielstädte et al., 2015; Mackay et al., 2021; Ehret et al., 2021) believe that methane emissions in the OGI are underreported by up to as much as 50% and according to Howarth (2014) previous studies

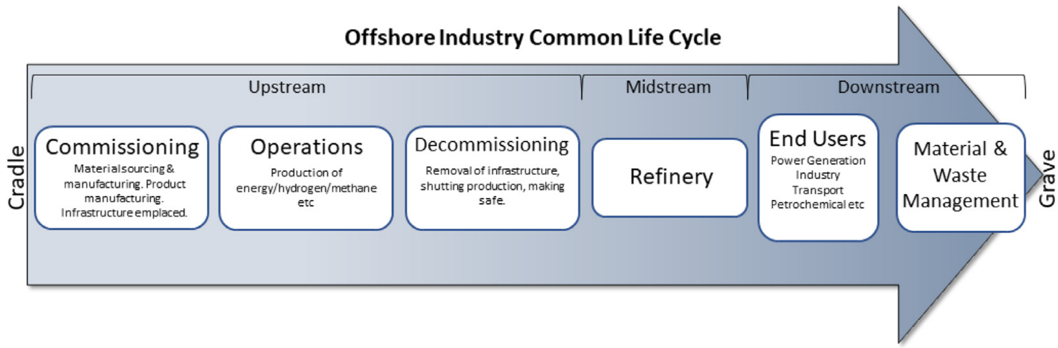


**Fig. 4.** Common elements of offshore industry life cycles.

of methane intensity rely on the same type of poorly documented and uncertain data. This is significant and could add a considerable warming effect to national inventories, especially where no satellite imaging is available.

## 3. Research methods and data

The methodology for modelling GHG emissions from the upstream section of various hydrogen production routes took a unique approach to life-cycle assessment (LCA) by mapping GHG emission intensity over time. Although life-cycle thinking was employed to ensure all statistically significantly sources of emissions were identified and included in the analysis, typical LCA was not deemed to suitably explore the dynamic nature of GHG emissions (the emissions intensity) throughout the lifetime of each technology, nor was it able to pinpoint activities for emissions reduction strategies.

Accurate and holistic GHG accounting need to include the operational and running emissions, as well as the emissions produced in planning, building, commissioning and decommissioning the scheme(s). Both direct and indirect sources of GHG emissions must be considered and must include sources such as acquisition and processing of raw materials, manufacturing materials and products, transport, electricity production and change of land use (marine or terrestrial).

Due to a severe lack of data the model design was limited to a top-down approach, and used the best available data, or the best available data analogue to ensure fair and appropriate values were used.

The study took the following steps:

**Step 1. Identify the technical routes to include in this study**.

Two routes were identified from the UK hydrogen strategy (Depatrment for energy security and Net Zero, 2021); 1. Green hydrogen, produced from the electrolysis of water using electricity produced from offshore wind turbines and 2. Blue hydrogen, produced from methane feedstock from UK offshore oil and gas assets, with the resultant exhaust GHG emissions captured and stored in offshore depleted oil and gas assets.

A wide range of carbon capture rates were found by this study, and because the capture rates would have a large impact on the results, it was decided that a range of theoretical and real-world capture rates would be used. To understand the impact of applying CCS to the production of hydrogen from methane feedstock, Grey hydrogen was also included in the results.

To compare GHG emissions from Green hydrogen, an alternative method was also modelled; producing hydrogen from electrolysis of water using electricity produced from the UK National grid.

Finally, to understand how the results compare to the current system, a business-as-usual scenario of continuing to combust methane was also included.

The technical routes identified to include in the study:

(1) Blue hydrogen production with real-world capture rate of 39%.
(2) Blue hydrogen production with theoretical capture rates of 56%.
(3) Blue hydrogen production with theoretical capture rates of 70%.
(4) Blue hydrogen production with theoretical capture rates of 90%.
(5) Grey hydrogen production (no CCS).
(6) Green hydrogen production, using offshore wind turbines to provide the electricity needed for electrolysis of water.
(7) Hydrogen produced via electrolysis of water, but with the electricity provided by the UK national grid.
(8) Business as normal case of continuing to combust methane.

**Step 2. Identify common life cycle stages.**

Three distinct and key stages common across all studied technologies were identified as commissioning, operations and decommissioning (refer to Fig. 4). This allowed data to be itemised by these factors, enabling comparisons to be made across the technical routes investigated.

**Step 3. Identify each element of the process for each technological route.**

The next stage was to identify the different stages of each technical route. This was important to ensure all potential sources of GHG emissions were accounted for. The process diagram for each technical route is illustrated in Fig. 5 and this was used to inform the model elements.

**Step 4. Collect data.**

Data was collected from a range of academic, industry and governmental publications and databases, such as the UK Health & Safety Executive (Health & Safety Executive (HSE), 2021) and BEIS (Department for Business Energy & Industrial Strategy (BEIS), 2019). Wherever possible real-time operations data was used, including methane production figures and emissions intensity figures from North Sea Transition Authority (NSTA) published data. Where there was a lack of real-time operations data available, data from academic studies were used. Data used for this study is presented in Tables 1, 2 and 3.

**Step 5. Data preparation and quality control**

To ensure accurate, holistic and fair accounts of GHG emissions it was important to identify all available sources of data and to assess the quality of that data (quality control). At all times the best available and most up-to-date data was identified and chosen to be used in the study. Where data was available, consistency of units was important so that like-for-like comparisons could be made between the different technological options. Large gaps in knowledge and data meant that some GHG emissions modelled were assumed.

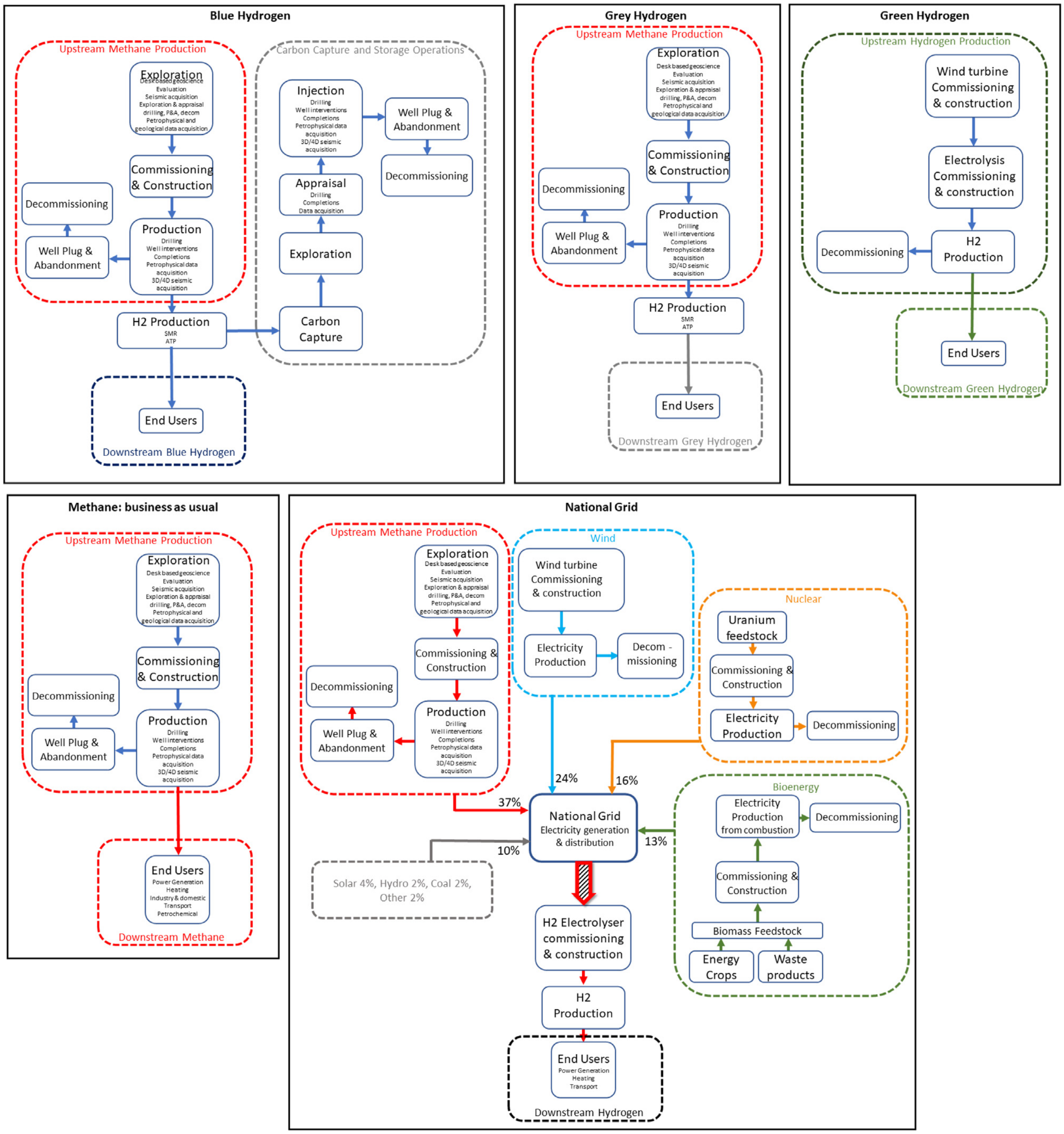


**Fig. 5.** Process diagrams for the technical routes investigated in this study. LCA boundaries are illustrated and include all statistically significantly upstream GHG emissions for each technology. One exception is that emissions due to OGI exploration activities are not included in the main study due to a lack of data.

**Table 1**
National grid Net Zero Strategy.

| National grid emissions intensity (including transmission and distribution losses) | | | | | | | |
|---|---|---|---|---|---|---|---|
| | $gCO_2$/kWh | kWh needed | Total $gCO_2$ | Total $kgCO_2$ | Total $tCO_2$ | Total $MtCO_2$ | Over 25 yrs |
| 2022 | 285 | 24,000,000,000 | 6.84E+12 | 6.84E+09 | 6840000 | 6.84 | 171 |
| 2030 | 100 | 24,000,000,000 | 2.4E+12 | 2.4E+09 | 2400000 | 2.4 | 60 |
| 2050 | 0 | 24,000,000,000 | 0 | 0 | 0 | 0 | 0 |

Methane data was normalised to the most up-to-date (Buendia et al., 2019) global warming potential (GWP) over a 20 year period ($GWP_{20}$ = 82) as different data used various GWPs over both 20 year and 100 year timeframes and therefore could not be compared directly. It also reflects more accurately the short-term warming potential of methane.

### Step 7. Determine a value for UK North Sea fugitive methane emissions

**Table 2**
GHG emissions from UK national grid 2020 energy mix.

| UK Grid to produce 0.5Mt$H_2$ per annum, 24 GWh | | | | |
|---|---|---|---|---|
| Main fuel source | Emissions | UK energy mix | per year | |
| | gCO2eq/kWh | % | kWh by % | MtCO2e |
| Coal | 1,000 | 2 | 480,000,000 | 0.48 |
| Gas | 500 | 37 | 8,880,000,000 | 4.44 |
| Biomass - range | 93 | 13 | 3,120,000,000 | 0.29016 |
| Solar | 58 | 4 | 960,000,000 | 0.05568 |
| Hydro | 30 | 2 | 480,000,000 | 0.0144 |
| Wind (both on and offshore) | 5 | 24 | 5,760,000,000 | 0.0288 |
| Nuclear | 5 | 16 | 3,840,000,000 | 0.0192 |
| Other | 15 | 2 | 480,000,000 | 0.0072 |

**Table 3**
Key data used to predict total greenhouse gas emissions for methane and Blue and Green hydrogen.

| Activity | Data | Unit | Reference | Data confidence | Note |
|---|---|---|---|---|---|
| UK production 'Operations GHG Emissions' | 19.89 | Mt$CO_2$ eqyr$^{-1}$ | Department for Business Energy & Industrial Strategy (BEIS) (2019) | low | Data uses many assumptions in methodology and does not include exploration, commissioning nor decommissioning GHG emissions. Nor does it include GHG emissions from product (i.e. combustion of HC). |
| UK $CH_4$ production emissions (50% of total) | 9.945 | Mt$CO_2$ eqyr$^{-1}$ | Department for Business Energy & Industrial Strategy (BEIS) (2019) | low | |
| Total UK $CH_4$ requirement for $H_2$ plans | 7 | % | Estimated | medium | Estimate based on the volume of produced HCs BEIS (2019), but will be dependent on total volumes of HCs produced. |
| Energy in $H_2$ | 141.8 | MJkg$^{-1}$ | Budsberg et al. (2015) | high | |
| $H_2$ requirements for 2.5GWy$^{-1}$ | 0.5 | Mt$H_2$ | Based on energy in $H_2$ | high | |
| $CH_4$ requirement for 1 kg$H_2$ | 3.04 | kg | Budsberg et al. (2015) | high | |
| $CO_2$ produced from 1 kg$H_2$ | 9.21 | kg | Budsberg et al. (2015) | high | |
| $CH_4$ required for 0.5Mt$H_2$ | 1.52 | Mt$CH_4$ | Department for Business Energy & Industrial Strategy (BEIS) (2019) | high | |
| $CO_2$ produced due to $H_2$ production | 4.605 | Mt$CO_2$eq | Budsberg et al. (2015) | high | |
| $CH_4$ production commissioning emissions | 2.07 | Mt$CO_2$eq | Estimated | low | Modelled at 3x operations emissions - no data available, emissions could be significantly higher. |
| $CH_4$ production operational emissions | 0.69615 | Mt$CO_2$ eqyr$^{-1}$ | Estimated | low | Methane production emissions increase year on year. See text for explanation. |
| $CH_4$ production decommissioning emissions | 1.035 | Mt$CO_2$eq | Estimated | low | Modelled at 50% of commissioning emissions. |
| $H_2$ production commissioning & decommissioning emissions | 1.486 | Mt$CO_2$eq | Cetinkaya et al. (2012) | medium | |
| CCS commissioning emissions | 2.07 | Mt$CO_2$eq | Estimated | low | $CH_4$ figures duplicated for modelling purposes as no data is available. It is likely to contain significant gaps and could be a significant underestimate. |
| CCS operational emissions | 0.69615 | Mt$CO_2$ eqyr$^{-1}$ | Estimated | low | |
| CCS decommissioning emissions | 1.035 | Mt$CO_2$eq | Estimated | low | |
| Wind turbine emissions intensity for 2MW offshore wind turbines | 14 | g$CO_2$ eqkWh$^{-1}$ | United Nations Economic Commission for Europe (UNECE) (2022) | medium | LCA figure includes operations and commissioning emissions but does not include decommissioning. |
| Wind turbine decommissioning emissions | 2 | Mt$CO_2$eq | Estimated | low | Modelled at 50% of commissioning emissions. |
| Electrolyser commissioning emissions | 122 | g$CO_2$ eqkWh$^{-1}$ | Mori et al. (2014) | medium | LCA figure includes operations and commissioning emissions but does not include decommissioning. |
| Electrolyser Decommissioning Emissions | 2 | Mt$CO_2$eq | Estimated | low | Modelled at 50% of commissioning emissions |
| Electricity required for 1 kg$H_2$ | 48 | kWh | Gardner (2009) | medium | |

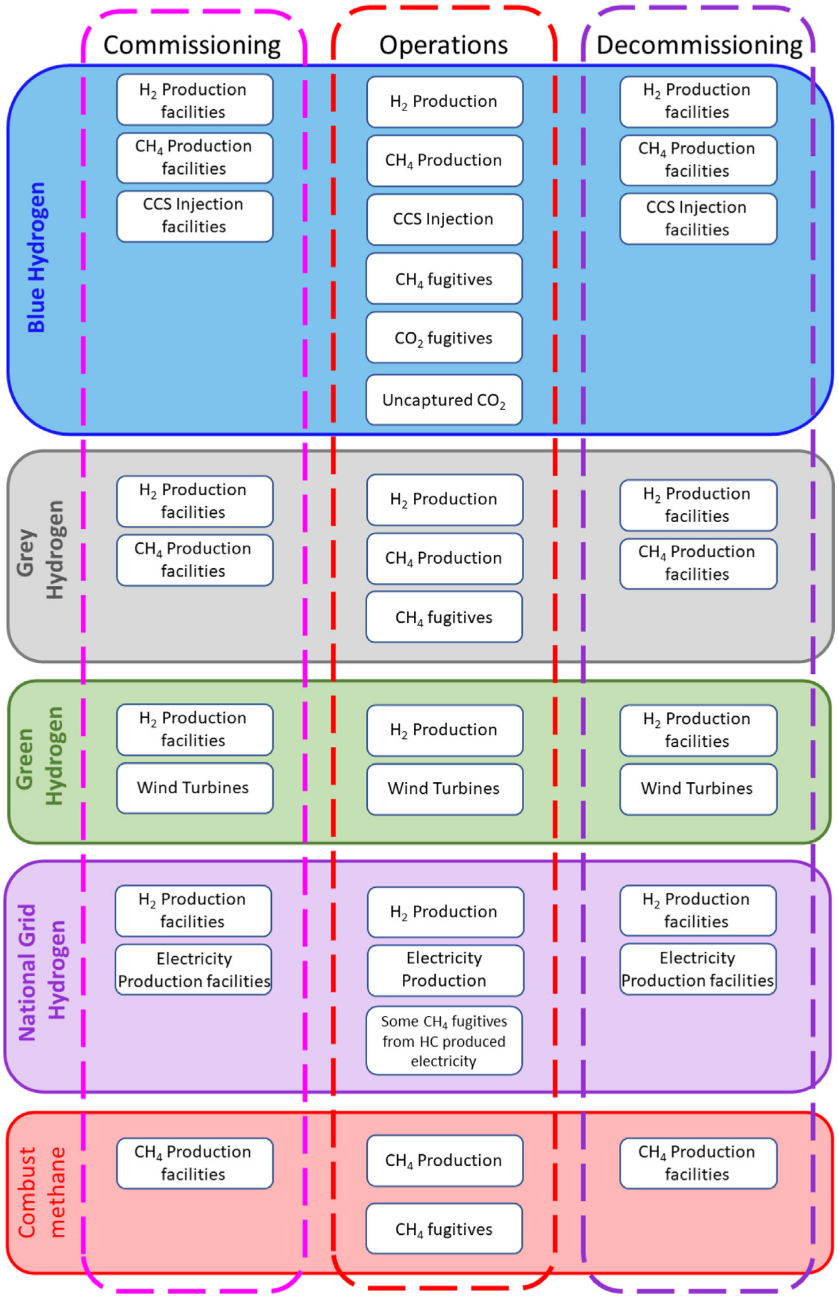


**Fig. 6.** Model elements for each of the technical routes.

This step was important as an accurate methane fugitive emissions value had not been determined for the UK North Sea to date and because even small volumes of methane have a large global warming impact. This was achieved by finding the possible sources of fugitive emissions (see literature review for discussion) and quantifying them by a percentage of methane production as this is the most common method for reporting methane intensity in other studies.

**Step 8. Define the model parameters.**

Each technical route was defined to produce the same amount of hydrogen per year, at 0.5Mt$H_2$ and this means that for Blue and Grey hydrogen, 1.52Mt$CH_4$ of feedstock would be required and 4.65Mt$CO_2$ of carbon dioxide would be produced and for Green and national grid hydrogen 24 GWh of electricity would be required. The GHG emissions to produce and combust 1.52Mt$CH_4$ of methane as a direct energy source (business as usual) was also included. Each technical route had its own set of model elements, as described in Fig. 6, and by defining these separate elements into the encompassing categories, of commissioning, operations and decommissioning we are able to create a simplified overarching equation to define the upstream GHG emissions model, which is:

$$E_{com} + E_{ops}(n + f(a)) + E_{decom} = ELT$$

Where;

$E_{com}$ is the total GHG emissions for commissioning

$E_{ops}$ is the total GHG emissions for operations

n is the number of years of operation

$f(a)$ is the increase in ops emissions due to age

$E_{LT}$ is the total lifetime GHG emission

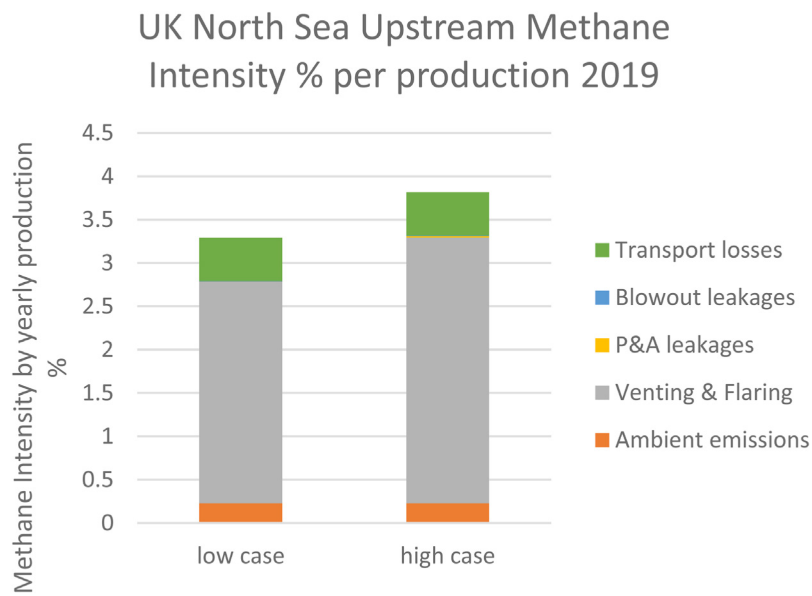


**Fig. 7.** UK North Sea upstream methane intensity as a percentage of production based on 2019 data. The emissions due to transport of $CH_4$ from offshore to onshore processing and $H_2$ production has the highest uncertainty as there are no published studies looking at this specifically and as such these emissions could be significantly higher.

**Table 4**
GHG emission sources from UK offshore methane production as a percentage of production. A nominal figure for fugitive emissions from transport has been included as no data is available.

| UK $CH_4$ Production 2019 | | | | |
|---|---|---|---|---|
| | bcm | $tCH_4$ | Reference | Data certainty |
| | 39.5 | 21883000 | Statista (2023) | High |
| **GHG Emission Source** | **% of Production** | | | |
| Ambient emissions | 0.23 | | Riddick et al. (2019) | Medium |
| Transport losses | 0.5 | | Mitchell et al. (1990) | Low |
| | **low case** | **high case** | | |
| Venting & Flaring | 2.550861 | 3.063453 | Oil & Gas Authority (OGA) (2020) | High |
| P&A leakages | 0.004113 | 0.016908 | Böttner et al. (2020) | Low |
| Blowout leakages | 0.007185 | 0.007185 | Leifer and Judd (2015) | Low |
| **Total** | **3.29216** | **3.817546** | | |

## 4. Results

Fig. 7 illustrates the low and high case for potential fugitive emissions for UK North Sea venting and flaring emissions, transport losses (from offshore to onshore), P&A leakages, ambient emissions and blowout leakages. The average of 3.5% was determined to be the best value for UK North Sea fugitive emissions to be used in the model. Table 4 shows the data used in the analysis.

Fig. 8 illustrates the lifetime GHG emissions for each technology per year and Fig. 9 illustrates the total GHG emissions over the technology's lifetime. The lifetime GHG emissions results are listed below in order of least impactful to most impactful:

1. Green hydrogen: $20MtCO_2e$.
2. Hydrogen produced via electrolysis using UK national grid electricity: $167MtCO_2e$.
3. Blue hydrogen with 90% theoretical capture rate: $201MtCO_2e$
4. Blue hydrogen with 70% theoretical capture rate: $225MtCO_2e$
5. Blue hydrogen with 56% theoretical capture rate: $242MtCO_2e$
6. Business-as-usual scenario of continuing to combust methane: $250MtCO_2e$.
7. Blue hydrogen with 39% real world capture: $262MtCO_2e$
8. Grey hydrogen: $282MtCO_2e$

The production of Blue hydrogen at a rate of $500{,}000tH_2$ per annum would require $1.52MtCH_4$ per annum (3.04 kg of methane feedstock for every kg of H produced) and would produce $4.605MtCO_2$ of carbon dioxide emissions every year (9.21 kg of $CO_2$ per kg of H produced) (Budsberg et al., 2015) but Green hydrogen produces no GHG emissions from either the feedstock (water) or process exhaust (see Table 5).

In Blue hydrogen, as oil and gas assets age, wells require more interventions, structures require more maintenance, and more leaks and fugitives will be released, thereby increasing annual emissions every year. This is reflected in a compound rate of increase applied to the $CH_4$ operations emissions and the fugitive emissions. A figure of 0.04% of production for fugitive emissions was used as the increase rate. This is a relatively small change, modelled on data from Riddick et al. (2019) but is based on only four gas wells and therefore data uncertainty is high. Methane extraction and production also carry high risk of accidental GHG releases, both pre- and post- well plug and abandonment (P&A) which need to be factored into the calculations.

The results show very clearly that over the lifetime of hydrogen production Green Hydrogen using offshore wind turbines to generate the electricity needed for electrolysis releases significantly less emissions than all other methods of hydrogen production by a factor of 10.

The Blue hydrogen lifetime GHG emissions results from this study were compared to the results from the Longden et al. (2022) study and Howarth and Jacobson (2021) study and showed

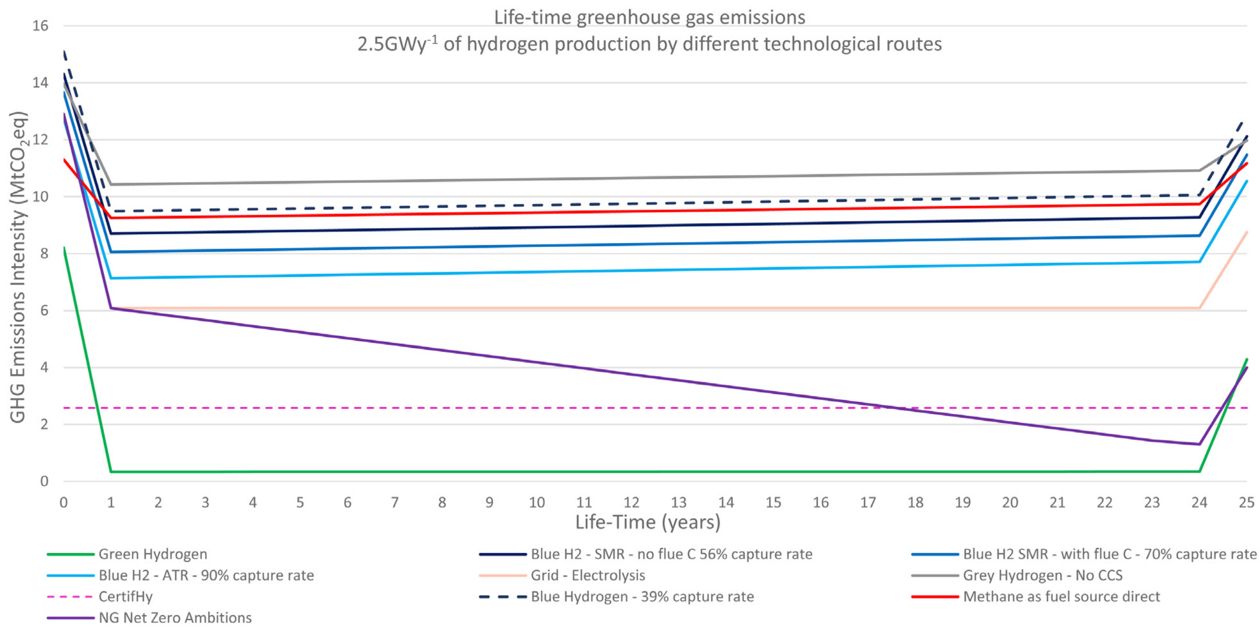


**Fig. 8.** Life-time GHG emissions intensity for upstream Blue $H_2$, Green $H_2$, Grey $H_2$ and $H_2$ produced using electrolysis from electricity provided by the UK grid over 25 year life-time with an annual production of 2.5 $GWy^{-1}$. UK national grid figures include current emissions intensity of production methods and the darker orange line represents the National Grid decarbonisation aims to reach Net Zero emissions by 2050. The results are compared to the 'business-as-usual' scenario of continuing to burn methane gas directly (shown in red). The Clean Hydrogen Partnership's CertifHy level is 36.4 gCO2eq/MJ of $H_2$ produced and is shown in pink. Emissions less than this are considered 'low carbon' under the scheme (CertifHy, 2019). (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

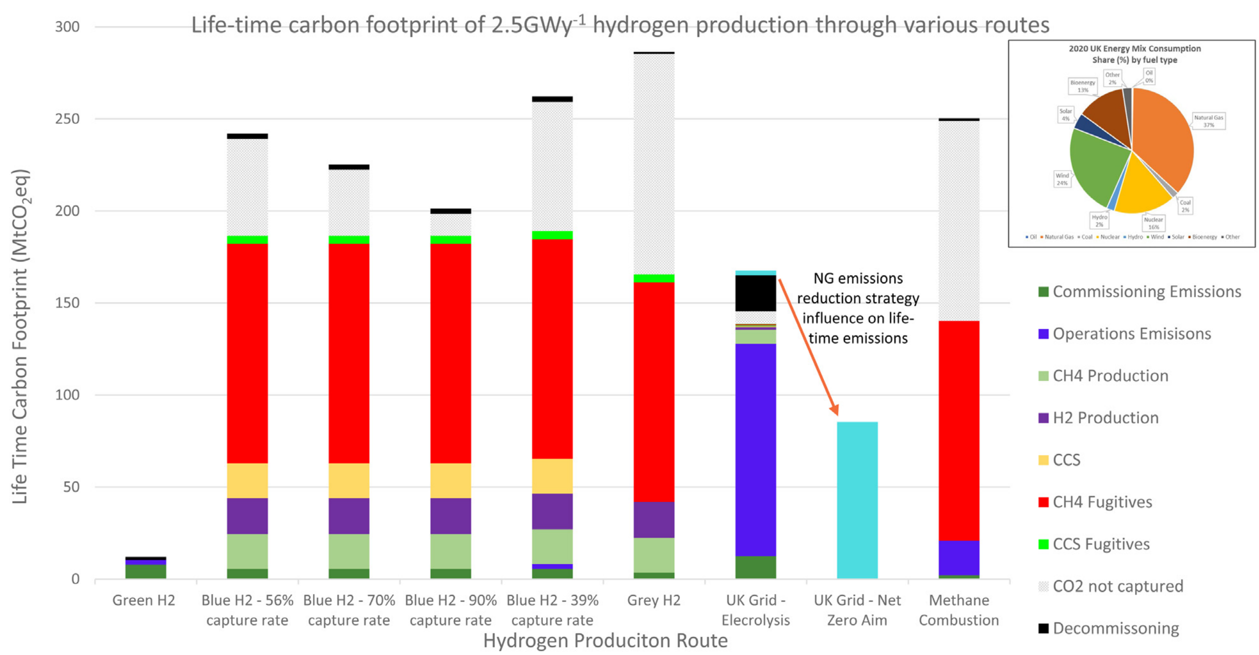


**Fig. 9.** Total Lifetime GHG emissions for offshore blue H2, offshore green H2, grey H2 and H2 production via electrolysis using electricity provided from the UK grid over 25-year life-time with an annual production rate of 2.5GW per year of H2. The data is broken down into emissions sources. The emissions from using UK grid electricity for electrolysis uses the UK energy mix as per the insert, for a larger version see figure 14 (Davies and Hastings, 2022). Energy Mix (Department for Business, Energy & Industrial Strategy (BEIS), 2021). (For interpretation of the references to colour in this figure legend, the reader is referred to the web version of this article.)

very similar values to the Howarth and Jacobson (2021) but were higher compared to Longden et al. (2022) for a number of reasons, illustrated in Fig. 10.

Firstly, in terms of fugitives (Longden et al., 2022) used IPCC fugitive emissions using the Guidelines for National Greenhouse Gas Inventories of between 1.7–2.58% (Buendia et al., 2019) whereas Gardarsdottir and Nekså (2021) study used fugitive $CH_4$ emissions from published studies using real world data, and although are mainly focussed on data from North America, this study has shown that the figure of 3.5% is also applicable to the UK North Sea region.

Secondly their study used published academic studies rather than industry data, and this data was not specific to offshore operations which will always have higher GHG emissions than

**Table 5**
GHG emissions for each activity by hydrogen production method.

Total lifetime GHG emissions to produce 0.5Mt/yr or 2.5GW/yr of $H_2$ in MtCO2eq

| Activity | Green $H_2$ | Blue $H_2$ | | | | Grey $H_2$ | $CH_4$ combustion | UK grid - electrolysis | UK grid – electrolysis – net zero aims |
|---|---|---|---|---|---|---|---|---|---|
| | | 39% capture rate | 56% capture rate | 70% capture rate | 90% capture rate | | | | |
| Commissioning | 7.87 | 5.63 | 5.63 | 5.63 | 5.63 | 3.56 | 2.07 | 5.34 | 5.34 |
| Operations | 8.59 | | | | | | 18.89 | 159.68 | 95.36 |
| $CH_4$ Production | | 18.89 | 18.89 | 18.89 | 18.89 | 18.89 | | | |
| $H_2$ Production | | 19.47 | 19.47 | 19.47 | 19.47 | 19.47 | | | |
| CCS | | 18.89 | 18.89 | 18.89 | 18.89 | | | | |
| Fugitive Emissions | | | | | | | | | |
| $CH_4$ Fugitives | | 119.29 | 119.29 | 119.29 | 119.29 | 119.29 | 119.29 | | |
| CCS Fugitives | | 4.41 | 4.41 | 4.41 | 4.41 | 4.41 | | | |
| $CO_2$ not captured | | 70.23 | 52.68 | 35.92 | 11.97 | 119.73 | 108.68 | | |
| Decommissioning | 3.94 | 2.82 | 2.82 | 2.82 | 2.82 | 1.41 | 1.41 | 2.67 | 2.67 |
| **Total GHG Emissions** | **20.40** | **259.62** | **242.07** | **225.31** | **201.36** | **286.38** | **250.34** | **167.68** | **103.37** |

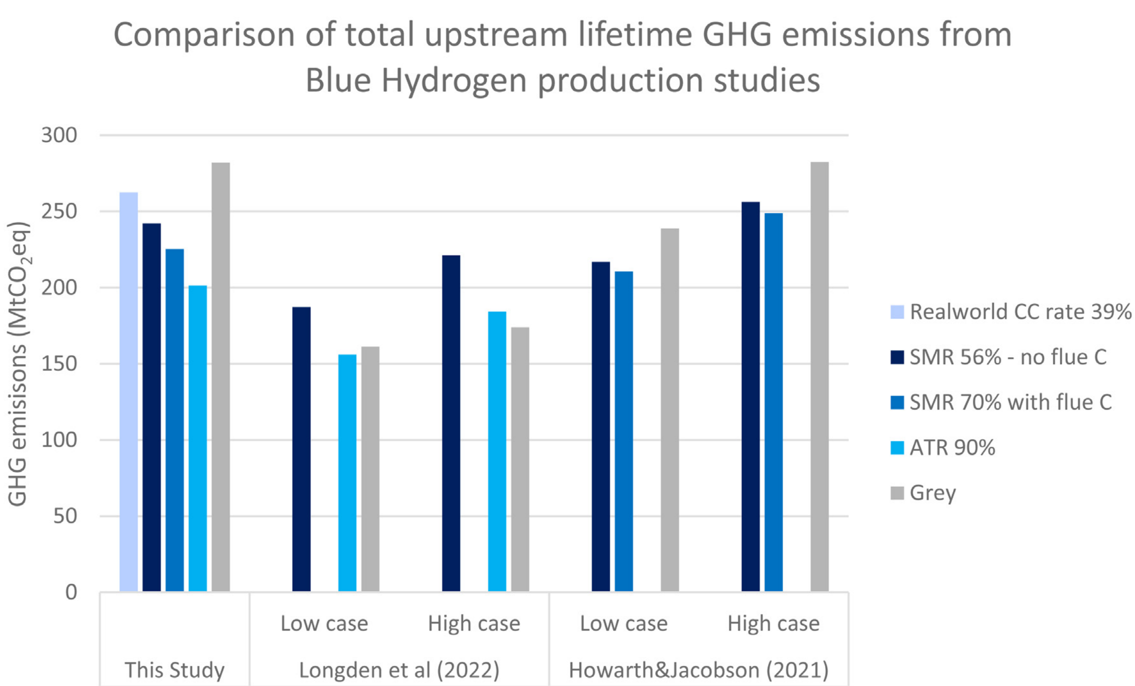


**Fig. 10.** Comparison of the results from this study compared to the results from Longden et al. (2022) and the results from Howarth and Jacobson (2021).

onshore operations due to the extreme nature of the environment. Furthermore, neither study used real-world CC rates of 39% (or lower) so do not have a comparison for this much lower level of CCS. and the inclusion (or not) of commissioning and decommissioning operations emissions.

## 5. Discussion

This study demonstrates that quantified, holistic, realistic and consistent GHG emissions methods are required to accurately predict life-time GHG emissions of different technical routes and to then compare these results to find the most suitable option for decarbonising.

The results show that Blue hydrogen will produce and release significantly large volumes of GHG emissions including high levels of methane fugitives, no matter the carbon capture rates. It also demonstrates that carbon capture rates need to be greater than 40% to have lower GHG emissions than burning methane as a direct fuel source. Current real-world commercial carbon capture rates (<39%) are much lower than reported theoretical capture rates from most academic studies and by industry (∼90%) and this study shows this has a significant impact on total GHG emissions calculated.

Importantly this work also demonstrates that both upstream and downstream methane fugitives, leakages and accidental releases pose a significant risk but have so far not been accounted for accurately in any carbon inventories. This is a serious concern as not only does methane have a much bigger impact on short term warming, but a significant and growing gap exists between GHG inventories and real-world data that measures atmospheric methane concentrations.

Furthermore, to produce 500,000t$H_2$ of Blue hydrogen would require at least 6.95% of total UK methane production (21.89Mt$CH_4$ 2019). The UK is a net importer of methane, and the consequence of increasing methane requirements due to Blue hydrogen production would in all likelihood increase the UK's reliance on methane imports. The UK has no control of the emissions intensity of gas production in other regions and this in combination with high fugitive emissions and emissions from transport will mean a further increase in the lifetime GHG emissions footprint of Blue H production. The current fossil fuel price increase and historic fluctuations mean that a future Blue $H_2$ economy will face the same risks and uncertainties of fluctuating feedstock price and this in combination with the current geopolitical landscape means that a reliance on Blue H will only serve to decrease energy security in the UK. Blue hydrogen will also likely divert investment away from renewables (IRENA, 2019) and increase our dependency on fossil fuels.

As OGI assets mature, operating emissions increase due to higher levels of maintenance of facilities, and more challenges extracting HCs or emplacing (injecting) $CO_2$ due to changing pressures in the reservoir; this means that the risks of fugitives and leakages will increase. Furthermore, there is no certainty that the emplaced $CO_2$ will remain in situ indefinitely and risks of leakages over the long term must also be considered in any future model. Long term monitoring of the CCS injection site and subsurface reservoir should be considered to confirm that all captured $CO_2$ has been stored and is not leaking. The only method for this currently is through 4D seismic. 4D seismic surveys produce 3D seismic data at different times over the same area, allowing the reservoir fluids to be imaged, mapped and compared over time (Sambo et al., 2020). The OGI have used these techniques to image hydrocarbon (HC) fluid movements through reservoirs for a number of years and they are successfully able to image the reduction in fluids within the reservoir over time. Seismic acquisition is expensive and has emissions cost associated, can take a number of months and is very much dependent on season, weather and other users of the sea. Techniques such as ocean bottom cables have been employed in several fields for repeated seismic acquisition over time, reducing ship time (and thereby emissions) as the cables are laid and left in place over the field's lifetime.

OGI data is particularly difficult to come by with no available published data from industry at all and very few academic studies focussing on this area. Furthermore, OGI exploration activity including drilling exploration wells, seismic acquisition and other front-end activities are also poorly understood with no published data available and are not considered in any NSTA published GHG emissions inventory

GHG emissions studies as a consequence of CCS activity including commissioning, operations and decommissioning, transport and operations to inject $CO_2$ into depleted oil or gas reservoirs are completely non-existent in the public domain and as such this study has used the same figures for $CH_4$ offshore production as it is a similar process, although in reverse. In fact, CCS activity is likely to have higher emissions than methane production for a number of reasons:

1. A higher volume of gas is produced from Blue hydrogen operations (4.065Mt$CO_2$ is created from an input of 1.52Mt$CH_4$),
2. $CO_2$ is much more corrosive than hydrocarbons (HCs) and more specialised materials (especially steel) are required that have higher manufacturing emissions than standard OGI assets.
3. $CO_2$ is a smaller molecule than $CH_4$ and therefore rocks which sealed HCs in a reservoir may not be as effective with $CO_2$, increasing the risk of seal failure and $CO_2$ leakages.
4. New wells and seismic will also be required, both of which have a high GHG emissions footprint.
5. Fugitive emissions of $CO_2$ from compression, transport and injection operations will also be a problem, and although it will have a lower impact than methane fugitives, this will still be significant over its lifetime.
6. Hydrogen is itself an indirect greenhouse gas and has a GWP of 5.8 compared to $CO_2$ (Reiter and Lindorfer, 2015).

According to Boren (2022), the UK's upstream OGI emissions intensity is estimated to have increased 3 kg of $CO_2$ per barrel of oil equivalent (boe) to 23kg$CO_2$/boe — higher than at any point since the industry regulator began monitoring the metric in2016. This illustrates that the OGI is already facing huge challenges in decarbonising its upstream emissions and the added resource pressures of a Blue $H_2$ economy and the expansion of CCS would only serve to increase this challenge. Blue hydrogen data gaps and their speculative GHG emission figures are illustrated in Fig. 10 and this indicates there may be vast GHG emissions not being accounted for because they are not even recognised by the industry or governing bodies, which could be more than 45Mt$CO_2$e, meaning the carbon footprint of Blue hydrogen would be significantly higher than modelled here. Future work should look at these gaps and improve the model.

According to Noussan et al. (2020) there are a high number of unresolved issues facing Blue hydrogen development including technical challenges as well as economic and geopolitical challenges and according to Longden et al. (2022), hydrogen supply chains that are based on fossil fuels may be incompatible with decarbonisation objectives and raise the risk of stranded assets. According to Cockburn (2021), Chris Jackson the chair of the UK Hydrogen and Fuel Cell Association body (UK HFCA) resigned from his post over the UK government's championing of Blue hydrogen, describing the technology as an expensive distraction. According to Ambrose (2021) the oil and gas industry (OGI) have used false claims over the cost of producing Blue hydrogen to win over the treasury and access billions in taxpayers subsidies.

Green $H_2$ on the other hand would enhance energy security and the development of local supply chains. Renewably produced hydrogen from wind is the most environmentally benign method available to produce hydrogen at scale and whilst costs may be high at present (Cetinkaya et al., 2012) the predicted rapid growth and technical viability will allow rapid expansion of $H_2$ produced in this way. The work presented here confirms this view and illustrates that although Green hydrogen has high front-ended emissions costs for commissioning, very low emissions costs during operations, maintenance and monitoring and no process GHG emissions mean this would have a significant positive impact on decarbonisation if it were replacing other high emitting technologies such as combusting methane.

There are however some significant challenges in terms of material requirements and material end-of-use-life options when planning Green hydrogen production. Whilst the majority of the structure of a wind turbine is made from steel which is easily recyclable, recycling emissions are very high, mainly due to shipping and re-manufacturing and operations to remove the structures are emissions intensive (Davies and Hastings, 2022). Furthermore, there is a significant and growing problem with decommissioned wind turbine blades from both onshore and offshore locations. The composite materials that blades are made from are extremely difficult to reuse, recycling can release large volumes of GHGs and currently produces low value materials that are difficult to find a use for. Finding appropriate materials or designs to remove this problem is important along with creating new recycling technology, supply chains and markets to accommodate current and potential future materials. Furthermore life-cycle thinking should be applied to all planning through the use of the Value Retention Model as described by Davies and Hastings (2022).

Other considerations that need to be taken into account when planning a systemic energy transition is the potential reuse of manmade structures already present in the marine environment. Davies and Hastings (2022) show that the reuse of structures not only retains the value in the materials and products previously used, but also reduces GHG emissions from decommissioning activity. Further GHG emissions savings are achieved by reusing objects because less new structures will be required in the commissioning stage.

Decisions made now will significantly impact the UK's Net Zero agenda, making the wrong decisions will make it more difficult to achieve Net Zero by 2050 as mandated by the UK government or 2045 as mandated by the Scottish government as well as the Paris Agreement legal commitments. A recent court case brought by the Good Law Project, Friends of the Earth and ClientEarth to the UK High Court ruled that the UK government has failed to show that its policies will reduce emissions sufficiently to meet its legally binding emissions targets and that the Net Zero Strategy failed to include enough information, including a lack of quantification of GHG emissions, for Parliament and the public to scrutinise their plans (Client Earth, 2022). This could have significant implications for the Net Zero strategy and the role of hydrogen production within that strategy.

Global decarbonisation strategies need to be agreed and thinking needs to change from the short term to the long term so that we can fully understand the impact of our decisions. How the remaining carbon budget is used and divided between different countries has not so far been discussed. One way of allocating a country carbon budget could be to look at the population. The UK has around 68 million people, 0.85% of the global population of 8 billion. Would it be fair to allocate 0.85% of the remaining carbon budget to the UK? This would equate to 2.75Gt$CO_2$e for 1.5 °C and 9.1Gt$CO_2$e for 2 °C of remaining UK carbon budget and currently produces around 455Mt$CO_2$e per annum (Department for Business, Energy & Industrial Strategy (BEIS), 2021).

Increasing the longevity of technologies should also be considered as a decarbonising tool. For example, if the life-time of a wind turbine can be increased from 25 years to 50 years the carbon footprint of that technology will be reduced by half.

The phrase 'low carbon' is often used by various actors, but the meaning is somewhat elusive, and it does not appear that there is a definitive definition of 'low-carbon'. The European Commission's CertifHy scheme state that 'low-carbon' hydrogen is any hydrogen production method where the GHG emissions produced are 60% less than their benchmark, which is the SMR process without CCS, in other words, Grey hydrogen. Any hydrogen production method and feedstock can be included, as long as GHG emissions (emissions intensity) are less than 36.4gCO2e/MJ (CertifHy, 2019) and this includes Blue hydrogen. However, the analysis presented here shows that no Blue hydrogen production scheme can realistically be operated under the CertifHy threshold, and that even the most benign method of hydrogen production (Green hydrogen) will have GHG emissions higher than the CertifHy threshold during both the commissioning and decommissioning stages of its lifetime. The scheme further aims to rebrand Blue hydrogen with emissions under their threshold as Green hydrogen, which will only lead to confusion between the current unofficial definition of Green hydrogen, this confusion could be avoided if a clear official hydrogen classification scheme is implemented. According to Longden et al. (2022) the CertifHy threshold may be widely adopted as a number of countries (including the UK) have already indicated they will adopt the scheme.

Although this model focussed on upstream GHG emissions, it is important to note that downstream GHG emissions can be considerable, mainly due to very high levels of fugitive emissions from leakages through very old and poorly maintained infrastructure, in some areas this can be more than 10% of the total transported gas and must be considered in any future studies.

Hydrogen is itself a GHG and although less impactful than methane, should still be taken into account as the $H_2$ molecule is significantly smaller than the $CO_2$ molecule and as such there is an increased risk of leakages and fugitives as well as safety concerns such as ignition. Furthermore, concerns about the release of air pollutants such as nitrogen dioxide when combusting hydrogen, particularly relevant if methane gas boilers are to be replaced with hydrogen boilers in urban areas where a build-up of NOx could cause poor air quality (Defra, 2020).

There is much uncertainty in the data presented with large and significant data gaps, especially for CCS operations, methane production, fugitives, leakages and accidental releases. Furthermore, an emissions gap exists between reported emissions and real-world data (Mooney et al., 2021) especially for methane. The true GHG emissions related to Blue hydrogen may be significantly higher if other factors are taken into account such as exploration drilling and seismic acquisition. This is illustrated in Fig. 11 which reveals potentially very large sources of GHG emissions not currently accounted for.

This study has not investigated GHG emissions associated with onshore renewables such as wind as this has not been included in the UK hydrogen strategy. There are many factors that can influence total GHG emissions for onshore wind, including change of land use which are not considered in the marine environment. Further work to enhance this model should include potential onshore Green hydrogen production facilities.

Downstream emissions are difficult to calculate due to the uncertainty of what process will be used to transport hydrogen to the customer and a comprehensive lack of data which is why it has not been included in the study at this point. However, future model development would benefit from the inclusion. If methane is used as a carrier gas (Depatrment for energy security and Net Zero, 2021), we should expect higher methane emissions than if the hydrogen was transported without the use of a carrier gas.

Hydrogen needs to be cooled and compressed for transport therefore there will be some emissions associated with the electricity production to run these systems. These indirect emissions are entirely reliant on the source of electricity production and the energy mix of the electrical system.

As well as incidental emissions occurring at the point of extraction and transport, significant amounts of $CH_4$ may be lost during above-ground transfer – often as leaks in pipeline, during venting and at compressor stations. Such losses are especially prevalent where the extraction, storage and supply structure is aged or poorly maintained. Due to high pressures involved, losses at compressor stations can be substantial (Mattus and Kallstrand, 2010) and are difficult to detect and intercept before they escape. International statistics of natural gas pipeline accidents show that artificial damage, construction errors, material defects, and corrosion are the common causes of natural gas pipeline leakages (Hou et al., 2020).

Very little published data exists for downstream leakages in Europe, but a study by Mitchell et al. (1990) investigating the leakage rates from the national grid found that old infrastructure means that the system is vulnerable to leakages, fractures and breakages. They found that increasing flow rates increases the leakage rates and that various parts of the system will have different leakage rates. They modelled various leakage rates and found that the average across the whole UK system has leakage rates of between 5.3–10.9% illustrated in Fig. 12 along with the upstream emissions.

The Clean Air Task Force (CATF) (Clean Air Task Force, 2021) found a large number of methane leaks from both onshore oil

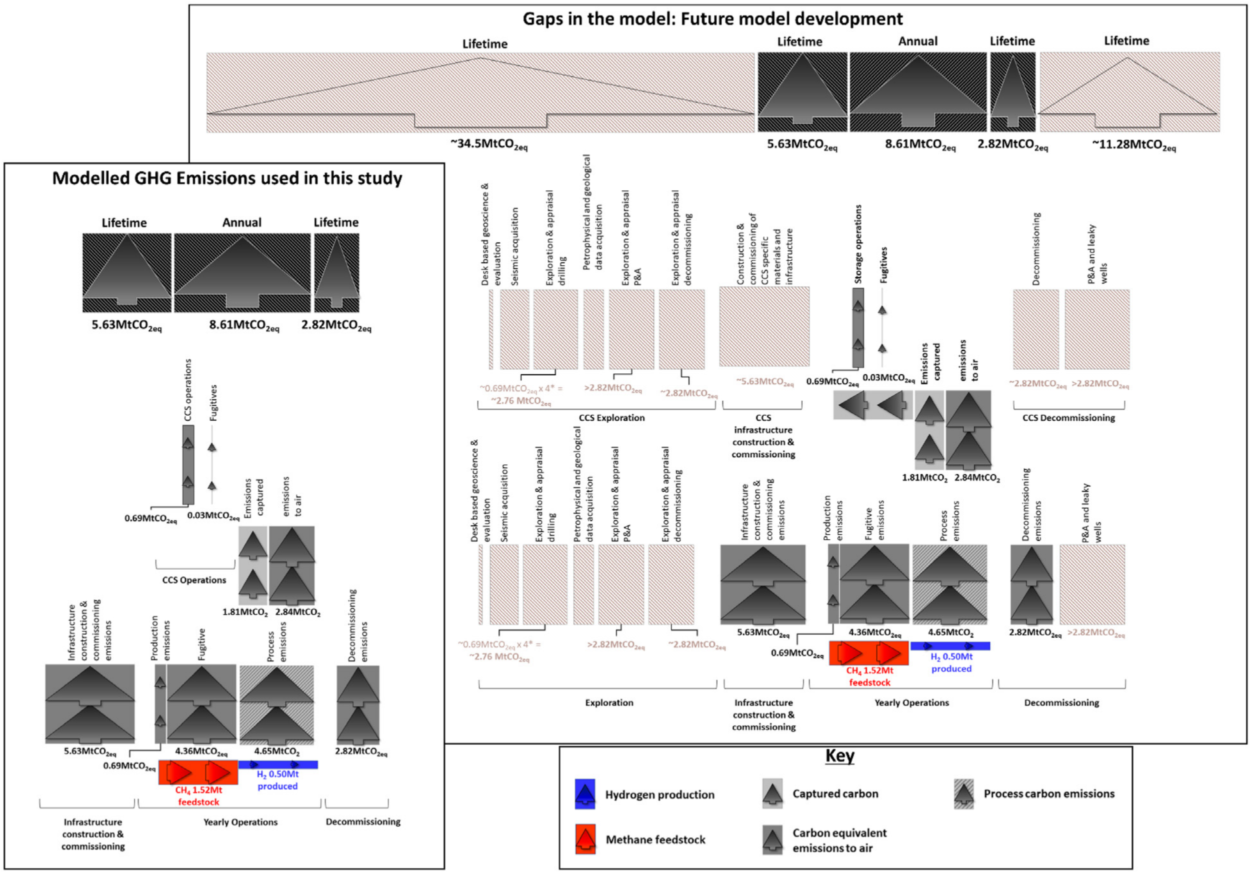


**Fig. 11.** Modelled Upstream GHG Emissions used in this study and potential gaps that need to be explored for further model development and improvement.

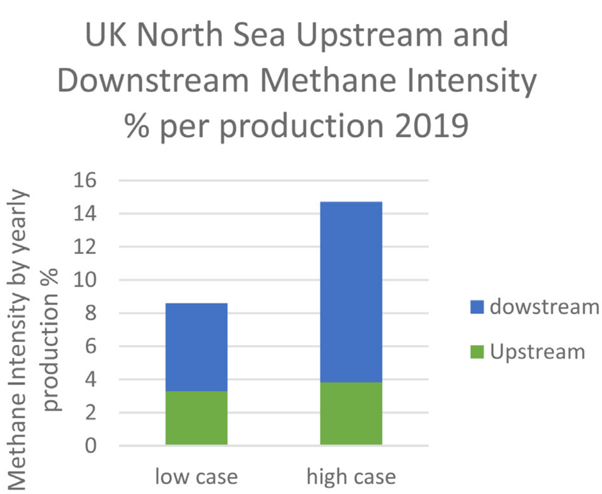


**Fig. 12.** Upstream and downstream emissions intensity as a percentage of production, UK North Sea.

production and natural gas transmission using infrared cameras. CATF investigated 17 onshore oil wells and found 13 of these to be leaking methane, they also investigated six National Grid gas compressor stations (out of a total of 25–30 nationwide) and found fugitive methane emissions at five of those sites. Two sites CATF visited had significantly large levels of methane emissions that could be classified as super-emitters and according to CATF (Clean Air Task Force, 2021) the emissions were being vented from emergency blowout systems at the site. At one site they found 10 separate sources of emissions.

There is clearly a very real disconnect between methane emission reporting and real-world emissions, and an urgent need for more holistic methane emission inventory methods globally as well as locally so that methane emission sources can be identified, quantified and a reduction strategy then put into place.

According to Roman-White et al. (2019) the use of current supplier-specific data is vital for accurately accounting for the variability of GHG emissions from natural gas, and this is also the case for the OGI where different environmental settings (for example onshore vs offshore), different fluid types, various ages of facilities and assets, the local policy framework and expectations will influence the potential for leakages and venting and flaring to occur.

The results presented show that Green hydrogen is the most environmentally benign method for producing hydrogen at scale with lifetime GHG emissions of 20Mt$CO_2$e. Blue hydrogen on the other hand will produce between 200-262Mt$CO_2$e, depending on the carbon capture rate achieved. Using the UK National Grid network for electricity to power an electrolyser will emit between 103-168Mt$CO_2$e, depending on the success of the National Grid's NetZero strategy and the 'business-as-usual' case of continuing to combust methane would release 250Mt$CO_2$e over the same lifetime.

Finally, this study shows that the IPCC default figures for methane fugitives in the OGI are too low and should be adjusted for more accurate quantifications, based on recent empirical observations and the studies presented here. This study shows that a figure of 3.5% is a realistic figure for the UK North Sea.

## 6. Conclusions

- The results illustrate that no hydrogen production method is under the 'low-carbon' CertifHy scheme during the commissioning and decommissioning stages and that no Blue hydrogen method can be considered 'low-carbon' at all.
- Blue hydrogen is unlikely to contribute to any GHG emissions reductions is not compatible with the Paris Agreement (Paris Agreement, 2015) and should not be included in the energy transition.
- Green $H_2$ using offshore wind to produce zero emissions electricity to power the electrolysis of water to produce hydrogen is a clear 'best option' of the technical routes modelled.
- Blue hydrogen will only have lower GHG emissions than combusting methane (business-as-usual case) if more than 40% of the total GHG emissions are captured and stored long term, but so far, no commercial CCS operations has achieved this.
- Measurement and monitoring of OGI facilities and plugged and abandoned wells would allow industry and policy makers to better understand the scale, nature and location of fugitives, leakages and accidental releases and would allow significantly more accurate GHG emission accounting. A UK wide offshore emissions monitoring program should be implemented that will undertake a rigorous assessment of current methane leakages from which a plan of action to stop these leakages can be formulated.
- It is imperative that a monitoring, reporting and verification (MRV) system is in place to ensure long term storage and maximum retention of $CO_2$ and that all other GHG emissions are correctly accounted for, especially fugitive emissions.
- With a very limited carbon budget remaining to avoid the worst effects of climate change we need swift and drastic reductions in GHG emissions, this means that any carbon investment in energy infrastructure changes needs to be right and right first time.

### CRediT authorship contribution statement

**Abigail J. Davies:** Conceptualization, Methodology, Investigation and analysis, Writing – original draft, Visualization. **Astley Hastings:** Writing – review & editing, Supervision, Data validation.

### Declaration of competing interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

### Data availability

Data will be made available on request.

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